Department of Energy

Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

POWER SERVICES

July 14, 2020
In reply refer to: PS-6

To Regional Customers and Interested Parties:

Bonneville Power Administration (Bonneville) kicked off the 2020 Rate Period High Water Mark (RHWM) Process with a customer workshop on May 19, 2020, at which Bonneville shared preliminary documentation including analyses and outputs. Bonneville held a public comment period from May 20 to June 3, 2020 and solicited feedback related to the preliminary documentation. Bonneville received 12 comments in total on the following topics:

1. Load Forecasting Changes
2. Tier 1 System Firm Critical Output (T1SFCO)
3. Historical T1SFCO Crosswalk
4. Average Water Impacts and Tier 1 Power Rates
5. RHWM and CRSO Timing
6. Extension of New Tribal Utility Contract High Water Mark (CHWM) Augmentation

Bonneville's responses to these comments are included below.

1. Load Forecasting Changes

Northern Wasco, Umatilla Electric, United Electric, Wells Rural Electric, and the Pacific Northwest Generating Cooperative on behalf of Raft River Electric Cooperative and Clearwater Power Company, all submitted comments requesting updates to the load forecasts used for their RHWM calculations. Bonneville is working with those utilities directly to update their load forecasts. Updated RHWM calculations will be published as part of the draft final RHWM outputs, which will be discussed at the August 4, 2020, RHWM Process customer workshop.

2. Tier 1 System Firm Critical Output (T1SFCO)

Northwest Requirements Utilities (NRU) requested additional details on the specific operational changes and MW impacts that resulted in the 110 aMW decrease to the T1SFCO associated with Columbia River System Operation EIS Preferred Alternative.

Due to the modeling used in determining RHWMs and rate case hydro studies, as well as the number of changes embedded in the current preliminary RHWM studies, it is extremely difficult to pinpoint exact aMW impacts associated with specific operational changes. Roughly estimated, Federal Columbia River Power System operational changes associated with the 110 aMW drop have around a 2 aMW impact, up or down, on firm generation based on 1937 critical water.

These operational changes include fish friendly turbines at Ice Harbor, allowing a deeper draft and changing flexibility at Dworshak, relaxing Minimum Operating Pool on the four Lower Snake projects, and increasing Minimum Operating Pool at John Day.

The modeling change accounting for about 100 of the 110 aMW drop in Firm Energy is the new Summer Sliding Scale operation modeled at the Libby and Hungry Horse dams. Overall, Libby and Hungry Horse are drafted deeper during relatively dry years than in wet years, and that larger draft provides additional water for a variety of downstream uses. However, the Upper Basin Sovereigns (UBS), comprised of the State of Montana, Kootenay, and Confederated Salish and Kootenai Tribes, have requested a specific operational change for quite some time. The UBS desired to tie the draft at Libby and Hungry Horse to local water volume forecasts rather than to system-wide water volume forecasts. The volume forecast based on 1937 critical water differs locally versus system-wide, and therefore using the local forecast causes substantially less summer drafts at both Libby and Hungry Horse. Drafting these headwater projects less not only causes a loss of generation onsite, but also causes generation losses at each project downstream.

Prior to the current 2020 RHWM Process, the RHWM studies did not model a Summer Sliding Scale operation. Instead, the September draft targets for the 80 years modeled in Bonneville's hydrosystem simulator model (HYDSIM) were set at either 20' or 10' from full at both Libby and Hungry Horse, with triggers based on the system-wide Water Supply Forecast (WSF) at The Dalles. For a given year, if the May forecast of April-August volumes at The Dalles predicted a dry year, below 72.5 Million Acre Feet (Maf, based on the 20th percentile from the 80 year water record), the September 20' draft target was set at Libby to 2439' and at Hungry Horse to 3540'**.** If the May forecast predicted a wet year, at or above 72.5 Maf, the Libby and Hungry Horse 10' draft targets were set to the higher elevations of 2449' and 3550', respectively. Again, on a system-wide basis, if the year was considered dry, additional water (or draft) would be released out of those headwater projects to support downstream uses.

The following table depicts the metrics used to determine the previous Libby and Hungry Horse September draft targets and resulting elevations using 1937 critical water within both our previous BP-20 FY20 and FY21 RHWM studies:

Headwater Project	May April-August WSF at The Dalles	WSF Trigger	September target	September Elevation
Libby	71.7 Maf	72.5 Maf	20' draft from full	2439'
Hungry Horse	71.7 Maf	72.5 Maf	20' draft from full	3540'

Starting with our current preliminary RHWM studies (May 2020), we included the change desired by UBS, basing the draft at Libby and Hungry Horse on local water volume forecasts, rather than system-wide water volume forecasts. As a result, the Summer Sliding Scale at Libby and Hungry Horse changes how these September draft targets are calculated in HYDSIM, and the July, August 15 and August 30 draft targets are based on achieving that revised September target as well.

The Summer Sliding Scale at Libby and Hungry Horse modeled in the May 2020 preliminary RHWM studies contains three major elements:

1) Rather than having only 20' or 10' drafts from full, the **<u>September draft targets are linearly interpolated</u>** between draft points, depending on the water supply forecast (WSF). For Libby, for a WSF between the 15th and 25th percentiles, the September targets are set by linearly interpolating between 2439' (a 20' draft), and 2449' (a 10' draft). For Hungry Horse, when the WSF is between the 10th and 20th percentiles, the September draft target is linearly interpolated between 3540' (a 20' draft) and 3550' (a 10' draft). Hence, the term "Sliding Scale" is used. For very dry years having forecasts below the 15th percentile, the draft target remains 20' from full. Similarly, for wet years with forecasts above the 85th percentile, the draft target remains 10' from full (except at Libby, where forecasts over the 85th percentile draft only 5' from full, but for the purposes of understanding 1937 operational effects, it does not have an impact).

2) The WSF triggers employed to determine the relevant percentiles are now based on the **<u>30 year record</u>** of NOAA April-August water volumes from 1981-2010, *not* on the 80 year water record from 1929-2008 of the 2010 Modified Flows.

3) The WSF used is not a "system" WSF for which the The Dalles forecast is often a proxy, but rather triggers are based on **<u>the May forecast of *local* April-August volumes</u>** at Libby or at Hungry Horse, expressed in Thousand Acre Feet (Kaf).

The following table depicts the new metrics, based on the above three elements, used to determine the Libby and Hungry Horse September draft targets using 1937 in both the current FY22 and FY23 RHWM studies (note that the WSF values used for interpolation, based on NOAA's at site 30 year record of April- August water volumes from 1981-2010 have been intentionally omitted, for clarity purposes):

Headwater Project	May April-August WSF local (at site)	September target	September Elevation
Libby	5378 Kaf	10' draft from full	2449'
Hungry Horse	1625 Kaf	10' draft from full	3550'

Using the local Libby and Hungry Horse WSF for April-August volume instead of the WSF at The Dalles essentially eliminates 10' of the 20' possible draft, and both projects end up being 10' higher in our current RHWM studies. While 1937 water resulted in a somewhat dry year at The Dalles in the Lower Columbia basin, it was only moderately below median at Libby. The local WSF at Hungry Horse was not relatively as big as Libby's, but was still bigger than using the system-wide forecast at The Dalles.

Not only is generation lost at both Libby and Hungry Horse headwater projects by being10' higher in 1937, it is lost at the downstream projects as well.

3. Historical T1SFCO Crosswalk

NRU requested a crosswalk of the changes to the T1SFCO from the BP-16 rate case to the current preliminary RHWM calculation. Unquestionably, fish operations have changed dramatically since the BP-16 RHWM FY16 and FY17 studies. Beyond typical updates (hydro project availabilities, Pacific Northwest Coordination Agreement project data and associated constraints, Canadian operations, Pacific NW loads), Bonneville has included these fish operational changes in the RHWM and rate case studies.

The following table compares various components from BP-16 RHWM through the BP-22 RHWM. The table shows that firm energy from the federal hydro projects using 1937 critical water is forecast to decline by 403 aMW (from 6302 aMW to 5899 aMW) since the BP-16 RHWM studies. A large part of that reduction is due to the increase in water volume that is spilled for fish passage purposes on the Lower Snake and Lower River projects.

The orange Sequential Delta columns show the difference in Fed Hydro generation based on 1937 water and on an 80 year average as compared to the immediately preceding Rate Case row. Each Rate Case row takes into account the spring and summer spill operational changes resulting in the Sequential Delta. Please note that previous customer workshop presentations may have contained different deltas based on different comparative studies.

The green columns in this table display approximations of the change in 1937 and 80 year average generation due to including fish operations that are different than those that were reflected in the previous rate case row. These approximations of fish operational changes are embedded in the Sequential Delta column. Finally, the footnotes describe unique or notable assumption changes (generally beyond typical updates) within each rate case study.

Rate Case (Avg of two FYs)	**Spring Spill Operational Basis**	**Summer Spill Operational Basis**	**1937 Fed Hydro** (aMW)	**Sequential Delta**	**Approx Fish Ops Change** (aMW)	**80 Yr Avg Fed Hydro** (aMW)	**Sequential Delta**	**Approx Fish Ops Change** (aMW)
BP-16 RHWM[1/]	2014 BiOp	2014 BiOp	6302	---	---	8459	---	---
BP-16 Final Proposal[2/]	2014 BiOp	2014 BiOp	6302	0	0	8410	- 49	0
BP-18 RHWM[3/]	2014 BiOp	2014 BiOp	6201	- 102	- 40	8425	15	-10
BP-18 Final Proposal[4/]	2014 BiOp	2014 BiOp	6210	9	0	8481	56	0
BP-20 RHWM[5/]	Block Spill Design	Performance Standard	6174	- 36	- 110	8343	- 138	- 110
BP-20 Initial Proposal[6/]	Spill to 120% TDG	Performance Standard	5986	- 188	- 190	8166	- 177	- 170
BP-20 Final Proposal[7/]	Revise spill caps	Revise spill caps	6070	84	80	8278	112	110
BP-22 RHWM[8/]	125% Flex Spill	Performance Standard	5899	- 171	- 50	8172	- 106	- 100

1/ FY17 included spring Maximum Transport of fish in eight driest years at Lower Granite, Little Goose and Lower Monumental dams, hence there was no spring spill at those projects. Studies revised the Early August Spill Curtailment dates.

2/ No spill operational changes, but hydro plant availabilities were revised.

3/ Removed spring Maximum Transport assumption, increasing spill and reducing generation in 1937 and seven other water years. Revised Early August Spill Curtailment dates by one to four days on Lower Snake projects, extending the summer spill season.

4/ No spill operational changes, but revised hydro plant availabilities and H/K tables at Chief Joe.

5/ Included spring Block Spill Design, alternating between a four week 'Gas Cap Spill Block' and Performance Standard Spill, significantly increases spring spill. August Spill Curtailment Dates were not forced to be sequential on Lower Snake projects, and generally decreases summer spill. Spill cap updates generally increase spill during both spring and summer. Included modeling refinements to more closely match current operations.

6/ Spill to 115%/120% TDG gas cap whenever possible in spring (FY 2018 Maximum Spill Operation). Removes August Spill Curtailment, spilling to the end of August.

7/ Included revised spill caps, based on data collected during the 2018 spill season that reflects spilling to the 115%120% TDG as much as possible in the spring.

8/ Preliminary studies. Includes 2020 125% Flexible Spill Operation, and modeling updates to reflect direction of FCRPS. Summer spill ends on August 14, transitions into small spill amounts through end of August.

4. Average Water Impacts and Priority Firm (PF) Tier 1 Power Rates

The Public Power Council (PPC) and Western Public Agencies Group (WPAG) requested additional information on how various reductions modeled in the BP-22 RHWM hydro studies impact the critical and average water amounts used in the calculation of PF Tier 1 power rates.

The studies needed to approximate PF Tier 1 power rate impacts are not complete at this time. Further, some of the values will depend on the results of ongoing discussions in pre-rate case workshops. Bonneville is still considering whether to provide an early, but incomplete, forecast of rates for Power and Transmission sometime during the summer. Providing an initial estimateof potential rates has a number of drawbacks, including consuming staff time producing the estimated rate levels and causing the pre-rate case process to focus on estimated rate levels (which will change) rather than other important pre-rate case policy and implementation issues. We appreciate, though, that customers may find these estimates useful for their own budgeting purposes. At this time, we have not yet decided whether to release an early PF Tier 1 estimate but will continue to consider it. Additional information on average water amounts will be discussed in future BP-22 Rate Case meetings. Further discussion of this issue can be found at our BP-22 IPR Follow-up website, https://www.bpa.gov/Finance/FinancialPublicProcesses/IPR/2020IPR/20200623-BP-22-IPR-Kick-Off-Workshop-Follow-ups.pdf

5. RHWM and CRSO Timing

Snohomish County Public Utility District expressed concern over the timing between the release for the CRSO Records of Decisions (RODs) and the conclusion of the BP-22 RHWM process. While the final CRSO EIS will not be released until late July and the final CRSO RODs are scheduled for release in September, at present Bonneville is using its best available estimates of future operational impacts that would impact the calculation of the T1SFCO.

6. **Extension of New Tribal Utility Contract High Water Mark (CHWM) Augmentation**

While generally supporting the extension of the time period for New Tribal Utility CHWM augmentation, in their responses NRU, PPC, and WPAG all noted that Bonneville should follow the procedures outlined in Section 13 and 14 of the Tiered Rates Methodology (TRM) to implement such a change.

In the Regional Dialogue Policy and TRM, Bonneville recognized the additional challenges Tribal utilities face as they form and grow their load service within Indian reservations by including a special accommodation that allowed Tribal utilities to increase their Contract High Water Marks for load growth in the aggregate of 40 aMW. The period for this tribal exception, included with augmentation up to 250 aMW for New Publics over the Regional Dialogue contract period, is expiring under the terms of the TRM. In its Regional Dialogue Policy Bonneville noted that if the overall 250 aMW for New Publics has not been reached, Bonneville would not be precluded from reconsidering the FY 2021 time period. *See* Long-Term Regional Dialogue Policy (2007) at 10-11. Bonneville believes this approach strikes a fair balance to support the needs of new tribal utilities as they establish their service to load within their respective reservations and the barriers they may face.

Because Bonneville continues to recognize the unique challenges that Tribal utilities face, and tribal utilities have not met the 40 aMW aggregate New Tribal Utility amount, Bonneville proposed to extend the exception that the TRM provided concurrently with the BP-22 RHWM process. The comments Bonneville received on this proposal underscored that the pathway to make the change would require a formal change to the TRM and use of the voting procedures it established. Bonneville concurs with this assessment on process and appreciates that the commenters did not express concern about the substance of the proposal. Making formal changes through the voting procedures of the TRM is a process that has been used only once. Recognizing that this process is time-intensive and that the public power workforce is engaged in several rate case processes, conducting routine business and responding to the frequently changing impacts of the COVID-19 pandemic, Bonneville is therefore not proposing a formal change be evaluated during the current RHWM process. In the event that a written request is submitted to Bonneville, we remain open to proposing an extension of the expiration date for the Tribal utility exception in section 4.1.6.4 of the TRM and exploring alternative approaches, consistent with the TRM to best meet the needs of Tribal utilities during the term of the Regional Dialogue Contracts. In addition, Bonneville recognizes that the unique challenges faced by Tribal utilities are not likely to go away after the Regional Dialogue contracts expire. Bonneville expects to work with Tribes and Tribal utilities on how to address their needs in the upcoming discussions on future Power Sales Contracts.

Bonneville appreciates all of the comments and input submitted during the Comment Period. Bonneville will hold a customer workshop on August 4, 2020 to discuss the draft final RHWM T1SFCO and draft final RHWM outputs for Fiscal Year 2022 and Fiscal Year 2023. The final public comment period extends from August 5 through August 19, 2020. The final RHWM outputs are scheduled to be made available on September 30, 2020.

Please contact Kathryn Patton (kbpatton@bpa.gov, 206-220-6785) for further information.

Sincerely,

Digitally signed by KIM THOMPSON
Date: 2020.07.14 13:53:41 -07'00'

Kim Thompson