BP-20 Rate Case Workshop: Power Rates

August 8, 2018

Agenda

- Loads and Resources
- Spill Surcharge
- Gas Price, Electric Price, and Secondary Revenue Forecasts
- Transfer Service

Load & Resources

Steve Bellcoff
Peggy Racht

General Hydro Updates

Pacific Northwest Coordination Agreement (PNCA) Project Data

- Update based on 2018 PNCA data, with an additional pumping update that will be part of next year's PNCA data. These updates include:
  - Grand Coulee net pumping estimates
  - BP18 Final Proposal included refinement of H/K data tables for several projects

Canadian Operations

- Update based on the 2022 Assured Operating Plan (AOP22) completed under the Columbia River Treaty. AOP22 provides the same Canadian Operation for FY20 – FY24.

Project Outages

- Update based on the latest long term maintenance and capital program forecasts from PGAF (Federal Hydro).

Reserves

- Update FCRPS reserve assumptions using most current information.

Loads

- Update based on latest forecasts produced by KSL (Agency Load Forecasting) and aggregated in LORA.

Spill Updates

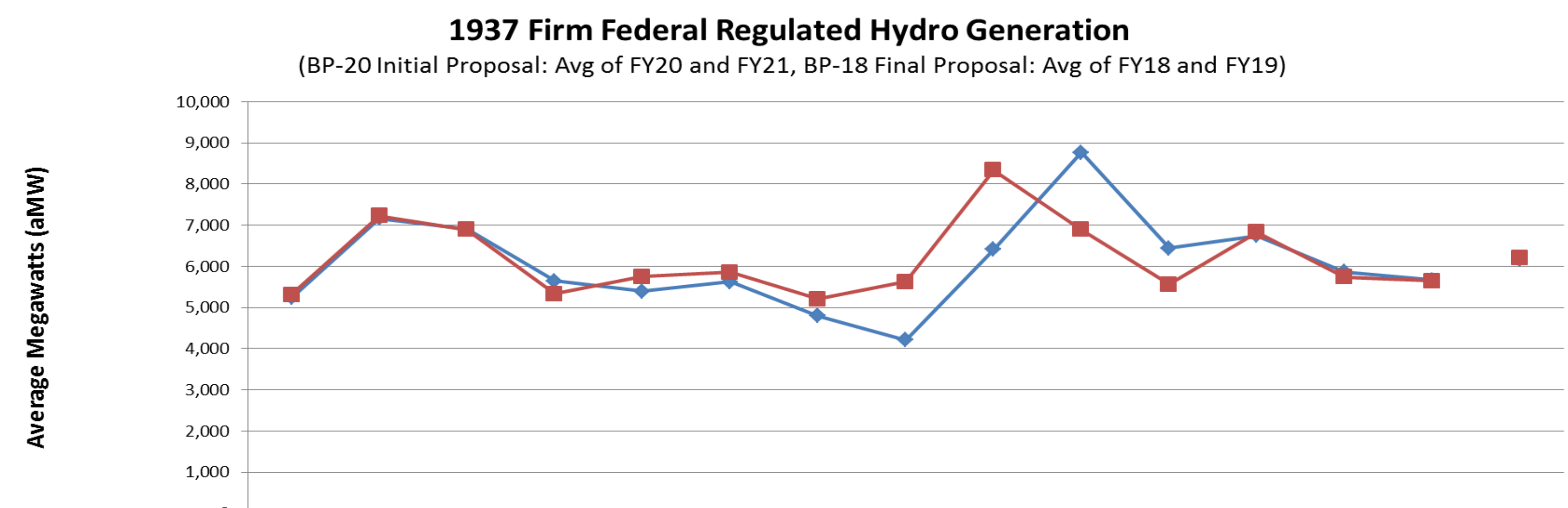
Spring Spill season based on Spill Block Design
- Applies a four week 'gas cap spill block' at each of the eight fish passage dams
- When not in gas cap spill, Performance Standard Spill applies
- FY20 applies gas cap spill later in spring season, FY21 applies gas cap spill earlier in spring season

Summer Spill season
- Change the August spill curtailment dates as specified by PG Fish Operations
  - Lower Granite: August 18th (previously August 14th)
  - Little Goose: August 21st (previously August 20th)
  - Lower Monumental: August 6th (previously August 22nd)
  - Ice Harbor: August 6th (previously August 23rd)
- Update spill operations based on Performance Standard testing results

Spill Cap Update
- CRSO Water Quality Team developed an updated set of spill caps for the fish passage projects, and PGPO added several refinements for Rate Case use as informed by historical data.

Overall, the Spring Spill Block Design significantly increases Spring spill, updates based on Performance Standard testing results changes spill slightly, changes in the August spill curtailment dates generally decrease Summer spill, and spill cap updates generally increase spill

Firm Hydro Comparison

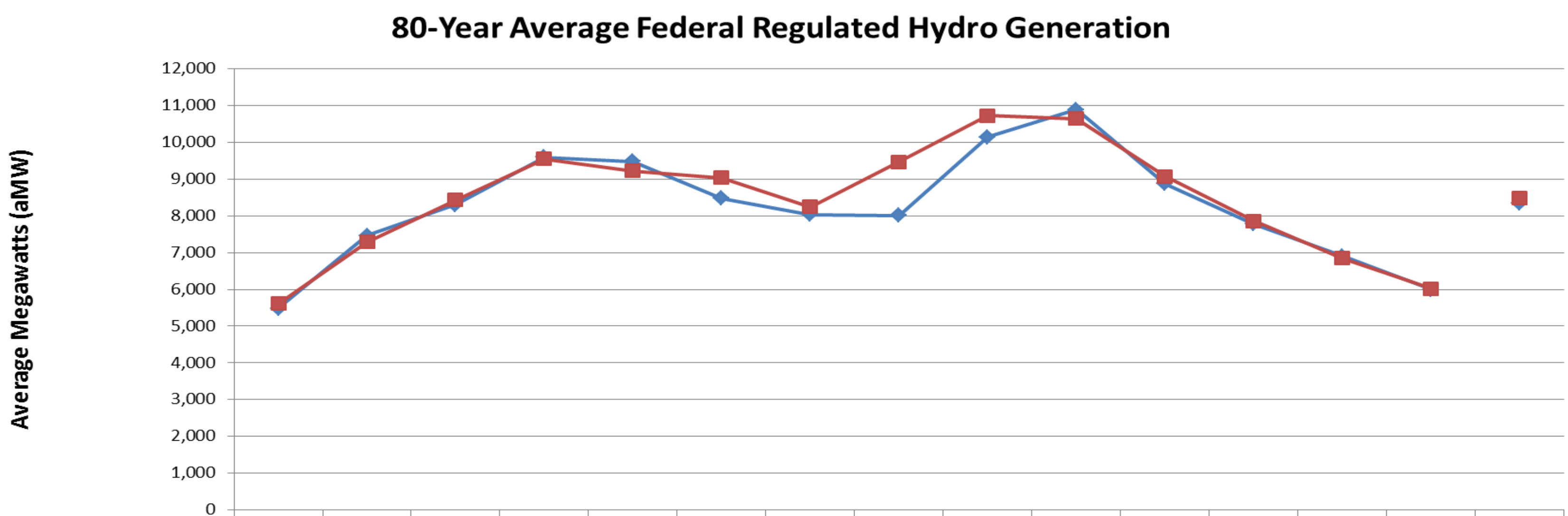


	Oct	Nov	Dec	Jan	Feb	Mar	Apri	AprII	May	Jun	Jul	AugI	AugII	Sep	Annual
BP-20 Initial Proposal	5,238	7,164	6,903	5,644	5,397	5,622	4,792	4,208	6,410	8,763	6,444	6,743	5,868	5,668	6,173
BP-18 Final Proposal	5,313	7,229	6,889	5,336	5,748	5,852	5,206	5,624	8,337	6,895	5,559	6,831	5,744	5,642	6,210
Difference	-75	-65	14	309	-351	-230	-414	-1,416	-1,927	1,869	885	-88	124	27	-37

- The loss of 37 aMW in annual Federal Hydro generation was due to a combined loss of 108 aMW from the spill assumption changes, a gain of around 35 aMW from increased outflows from a new Canadian Operation, and a net gain of around 36 aMW from several project operational refinements.

  (-37 aMW = -108 aMW + 35 aMW + 36 aMW)

Average Hydro Comparison



	Oct	Nov	Dec	Jan	Feb	Mar	AprI	AprII	May	Jun	Jul	AugI	AugII	Sep	Annual
BP-20 Initial Proposal	5,485	7,464	8,306	9,598	9,478	8,480	8,035	8,010	10,149	10,889	8,879	7,781	6,905	5,990	8,333
BP-18 Final Proposal	5,608	7,284	8,430	9,554	9,227	9,040	8,249	9,469	10,730	10,646	9,069	7,857	6,844	6,022	8,481
Difference	-124	180	-124	45	252	-560	-214	-1,459	-581	244	-190	-77	62	-32	-148

- The loss of 148 aMW in 80-year average annual Federal hydro generation was due to a combined loss of 116 aMW from the spill assumption changes, a loss of 15 aMW from the new Canadian Operation, and a loss of 17 aMW from a refinement of several project operational changes.

  (-148 aMW = -116 aMW - 15 aMW - 17 aMW)

BP-20 Preliminary Load Forecast
2-Year Average Comparison: FY2020-21 & BP-18 Final Rate Case FY2018-19

- **Total Federal Firm Load Obligation are lower by -47 aMW**
  - **Firm Obligations lower by -2 aMW**
    - Increased Load Following obligations (+45 aMW)
    - Increased Tier 1 Block (+26 aMW)
    - Reduced Slice obligations (-83 aMW)
    - Increased DSI obligation (+13 aMW)
  - **Other Contract Obligations lower by -83 aMW**
    - Expiration BPA/AVWP WNP-3 Set. (-47 aMW)
    - Reduced Canadian Entitlement. (-20 aMW)
    - Expiration BPA/PG&E Wind Shaping (-17 aMW)
  - **Contract Firm Surplus Sales increased by +39 aMW**
    - Updated Firm Surplus Sales (+39 aMW)
    - Firm Surplus Sales in both years

BP-20 Preliminary Resource Forecast

2-Year Average Comparison (1937 Critical Water): FY2020-21 & BP-18 Final Rate Case FY2018-19

- **Total Federal firm resources are lower by -47 aMW**
  - **Hydro Generation forecast lower by -38 aMW**
    - Reduced for spill assumption changes (-108 aMW)
    - Increased from outflows in Canadian Operation (+35 aMW)
    - Increase from operational refinements (+36 aMW)
  - **Other Resource forecast increased by +34 aMW**
    - Increased CGS generation forecast (+36 aMW)
    - Reduced Wind generation forecast (-2 aMW)
  - **Contract Purchase forecast lower by -18 aMW**
    - Expiration BPA/PAC wind shaping (-2 aMW)
    - Expiration BPA/PG&E wind shaping (-16 aMW)
  - **Reserves and Transmission losses forecast increased by +1 aMW**
  - **System augmentation forecast decreased by -26 aMW**

BP-20 Preliminary Load Forecast
Detailed 2-Year Average Comparison: FY2020-21 & BP-18 Final Rate Case FY2018-19

2-Year Average Comparison BP-20 Initial 8/1/2018 and BP-18 Final 5/01/2017 *(Energy in aMW)*		BP-20 Initial Proposal (FY20-21)	BP-18 Final Study (FY18-19)	Difference 2-Year Average	Comment
Federal Load Obligations					
1.	**Firm Obligations**	**7,019**	**7,021**	**-2**	**Firm obligation changes:** - Increased Load Following obligations (+33 aMW) - Increased Federal Agencies Obligation (+12 aMW) - Increased Tier 1 Block (+26 aMW) - Reduced Slice obligations (-83 aMW) - Increased DSI obligation (+13 aMW)
2.	*Load Following*	*3,100*	*3,067*	*33*	
3.	*Federal Agencies*	*130*	*118*	*12*	
4.	*USBR*	*179*	*180*	*-1*	
5.	*Tier 1 Block*	*539*	*513*	*26*	
6.	*Slice Block*	*1,415*	*1,487*	*-71*	
7.	*Slice Output from T1 System*	*1,570*	*1,582*	*-12*	
8.	*DSI Obligations*	*87*	*74*	*13*	
9.	**Other Contract Obligations** ***(w/o Firm Surplus Sales)***	**470**	**553**	**-83**	**Other contract obligaton changes:** - Expiration BPA/AVWP WNP-3 Set (-47 aMW) - Reduced Canadian Entitlement. (-20 aMW) - Expiration BPA/PG&E wind shaping (-17 aMW)
10.	*Exports*	*457*	*491*	*-35*	
11.	*Intra-Regional Transfers (Out)*	*13*	*62*	*-48*	
12.	**Firm Surplus Sale**	**127**	**88**	**39**	
13.	**Total Firm Obligations** ***(Sum lines 1+9+12)***	**7,616**	**7,662**	**-47**	

BP-20 Preliminary Resource Forecast

Detailed 2-Year Average Comparison (1937 Critical Water): FY2020-21 & BP-18 Final Rate Case FY2018-19

2-Year Average Comparison BP-20 Initial 8/8/2018 and BP-18 Final 5/10/2017 *(Energy in aMW)*	BP-20 Initial Proposal (FY20-21)	BP-18 Final Study (FY18-19)	Difference 2-Year Average	Comment
Federal Resources				
14. Net Hydro	**6,570**	**6,609**	**-38**	**Hydro generation forecased were:** - Reduced for spill assumption changes (-108 aMW) - Increased from outflows in Canadian Operation (+35 aMW) - Increase from operational refinements (+36 aMW)
15. Regulated Hydro - Net	*6,219*	*6,257*	*-38*	
16. Independent Hydro - Net	*348*	*348*	*0*	
17. Small Hydro Resources	*3*	*3*	*0*	
18. Other Resources	**1,111**	**1,077**	**34**	**Other Resouces changes:** - Increase in CGS generation (+36 aMW) - Reduced Wind generation (-2 aMW)
19. Cogeneration Resources	*0*	*0*	*0*	
20. Large Thermal Resources	*1,055*	*1,019*	*36*	
21. Renewable Resources	*56*	*58*	*-2*	
22. Contract Purchases ***(w/o Augmentation)***	**170**	**188**	**-18**	**Contract purchase changes:** - Expiration BPA/PAC wind shaping (-2 aMW) - Expiration BPA/PG&E wind shaping (-16 aMW)
23. Imports	*1*	*1*	*0*	
24. Intra-Regional Transfers (In)	*2*	*20*	*-18*	
25. Non-Federal CER	*137*	*136*	*0*	
26. Slice Transmission Loss Return	*30*	*30*	*0*	
27. Reserves & Losses	**-235**	**-236**	**1**	**Changes in Federal resource stack (+1 aMW)**
28. Transmission Losses	*-235*	*-236*	*1*	
29. Total Net Resources ***(Sum lines 14+18+22+27)***	**7,616**	**7,636**	**-21**	
30. System Augmentation	**0**	**26**	**-26**	
31. Total Resources w/Augmentation ***(Sum lines 29+30)***	**7,616**	**7,662**	**-47**	
32. Federal Surplus/Deficit ***(Sum lines 31 less line 13)***	**0**	**0**	**0**	

Spill Surcharge

Daniel Fisher

Nancy Parker

Background

- The BP-18 initial proposal rates were based on studies that modeled spill in accordance with the 2014 BiOp.
- The Spring 2017 district court injunction called for more spill than under the 2014 BiOp, but the spill plan for FYs 2018 and 2019 would not be known when final BP-18 rates were calculated.
- The rates must be set to recover the revenue requirement; however, BPA did not know what the magnitude of the revenue reduction due to increased spill would be. Therefore, BPA proposed and adopted the Spill Surcharge which approximated what the rates would have been had we known the spill plan when calculating final rates.
  - The Spill Surcharge also provided for the Administrator at his discretion to use spending reductions to offset the increased cost.

Spill Plan for FYs 2020/2021

- There are certain key differences in the circumstances surrounding the spill assumptions used to set rates for BP-20 relative to BP-18.
  - BPA expects a new BiOp for operations during the period 2019-2021, and
  - the final planned spring spill for FY 2019 will be implemented (and therefore known) before final BP-20 rates are calculated.

- Given this, BPA may not need to rely on the Spill Surcharge for cost recovery the same way it did in BP-18.

- An alternative to the BP-18 approach would be to remove the Spill Surcharge and set final rates on the known planned spill for FY 2019; or, if known at the time final studies must be run, the planned spill for FY 2020/2021.

- For the initial proposal under either the BP-18 approach or the BP-20 alternative, BPA would likely set the initial rates assuming a block spill design.
  - Block spill design is under review currently through the BiOp consultation process.
  - Used in RHWM Process to determine RHWMs and other outputs. (RHWMs determine the amount of power that customers can purchase at the Priority Firm Tier 1 rate.)
  - Reduces BPA’s cost recovery or customer Spill Surcharge by roughly half of what was observed in FY 2018.

Modeling: Effect of Spill Plan

- All else equal, BPA estimates that the difference in incremental spill between the 2014 BiOp and block spill plans would be approximately half of the difference between the 2014 BiOp and gas cap spill plans.

Compare spill plans:	80-Year Average FY18 Net Cost to non-Slice Customers (before spending reductions):
2014 BiOp and Gas Cap	$22 million
Block Spill Design and Gas Cap	≈ $11 million

Spill Surcharge: BP-20 Initial Proposal alternatives

Alternative 1. Keep Spill Surcharge

The Spill Surcharge increases power rates to approximately what they would have been if actual spill plans differ from what was assumed when setting final rates. The Spill Surcharge formula uses final rate case analyses with updated spill plans, and allows the Administrator to reduce budgets to offset the full surcharge.

Alternative 2. Eliminate Spill Surcharge

Rates would be based on best available information regarding the spill plan to set rates that recover the revenue requirement.

Spill Surcharge: BP-20 Initial Proposal Alternative 1

Alternative 1. Keep Spill Surcharge

Pros

- Straightforward calculations using data/analyses that have been through rate case
- Staff will have gained experience from implementing Spill Surcharge in FYs 2018/2019.
- Rates are set to recover revenue requirement

Cons

- Adds more uncertainty to rates during a rate period; power customers also subject to Oversupply rate and CRAC.
- Implementation workload, especially in second year of rate period when rate case is underway.

Spill Surcharge:
BP-20 Initial Proposal Alternative 2

Alternative 2. Eliminate Spill Surcharge

Pros

- Limits possible changes to rates within rate period.
- Recovers revenue requirement
  - Can reasonably forecast net secondary revenues in order to set rates that will recover revenue requirement. If *actual* net revenues are low, CRAC provides adequate risk mitigation.
- Workload
  - Rate case workload limited
  - No implementation workload (especially important in rate case year)

Cons

- If spill were to be dramatically higher than the rate-setting assumption, additional revenue provided through a Spill Surcharge could prevent the use of limited financial reserves and more timely help BPA recover its lost revenue relative to a CRAC.

Spill Surcharge:
Staff Preliminary View for BP-20 Initial Proposal

- Staff presently recommends eliminating the Spill Surcharge: The rates staff believes that circumstances have changed enough that BPA can set its rates on the best information available and manage the uncertainty the same way it does its other sources of uncertainty (financial reserves and the CRAC).

- Under such a proposal, the initial rates would be most likely set assuming the block spill design. The final rates would be set on known FY 2019 planned spill operation or, if known at the time final studies must be run, then the planned spill operation for FY 2020/21.

Gas Price, Electric Price, and Secondary Revenue Forecasts

James Vanden Bos
Eric Graessley
Margo Kelly
Matt Germer

3-Year Fundamental Outlook and Uncertainties

Demand – Incremental from CY 2018 through CY 2021

- LNG Exports: 5 Bcf/d (Actual capacity is higher, utilization is price sensitive.)
- Industrial Demand: 1.4 Bcf/d
- Mexican Exports: 1.5 Bcf/d
- Power Burn: 2.5 Bcf/d

Supply

- Gas rigs hit bottom at around 60 in summer of 2016. They now stand at around 160, and production is on a roll.
- Additionally, oil rigs bottomed out around 320 in late spring, 2016, and are now at 920+. Associated gas is a major force in the market.
- US Production is expected to grow by over 10 Bcf/d through 2021.

Uncertainty

- Weather: For sake of modeling and planning, assume historical average.
- Rate of technological advancement: How far have production costs fallen, how much lower will they go?
- Can production match demand, or are we stuck in boom and bust cycles?
- How much will gas pipeline capacity constraints in the NE, Western Canada, and the Permian impact downstream basis pricing?
- At what rate will LNG export terminals be utilized?

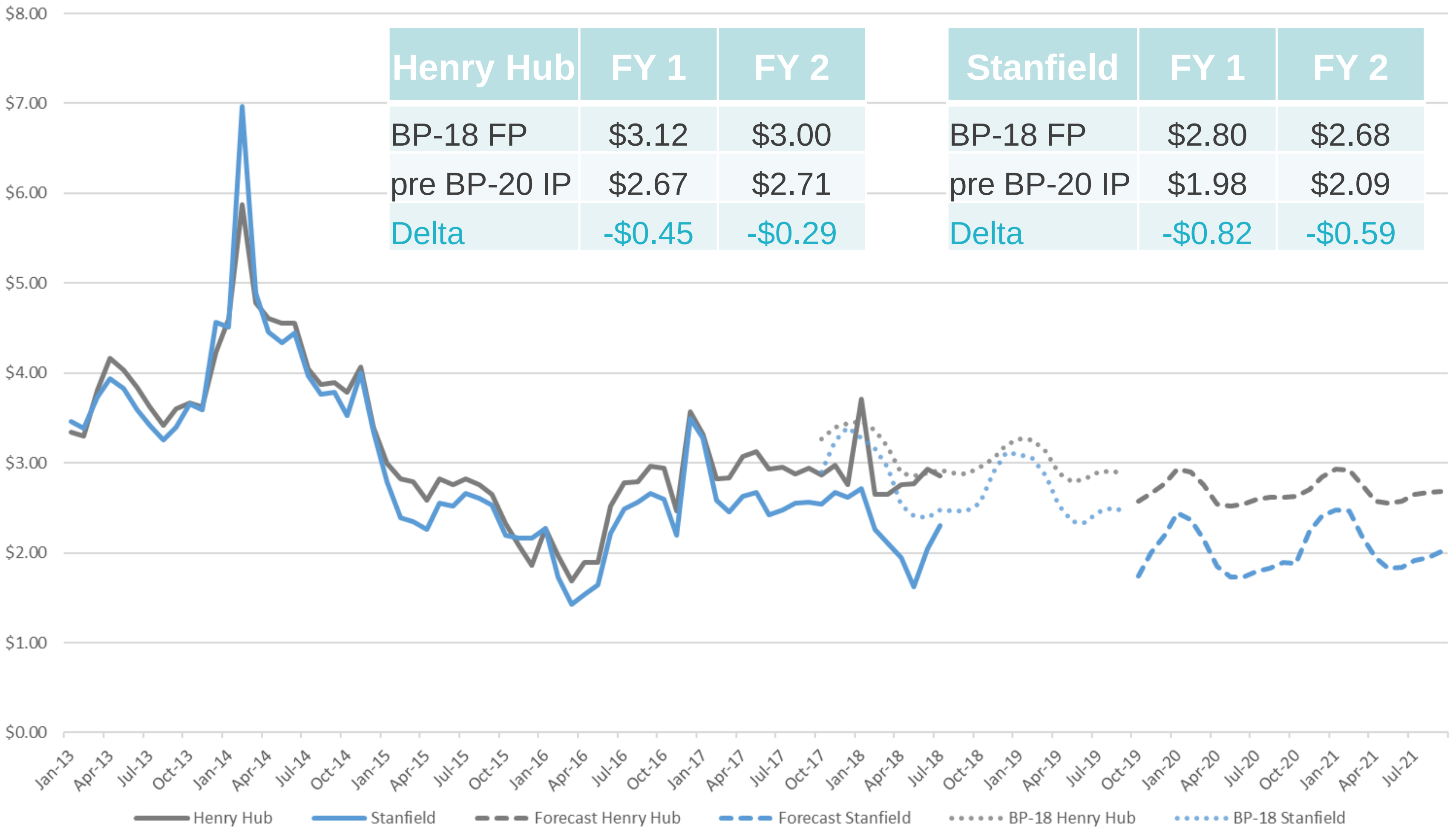
Pacific Northwest – Plenty of Supply

- The PNW is surrounded by inexpensive gas supply
- Main demand hubs are located in California
  - PNW is essentially a pass-through demand region
- PNW can expect sustained discounts to Henry Hub for the next few years
- PNW pricing is decoupling from Henry Hub pricing

Gas Prices – Historical and Outlook

Henry Hub	FY 1	FY 2
BP-18 FP	$3.12	$3.00
pre BP-20 IP	$2.67	$2.71
Delta	-$0.45	-$0.29

Stanfield	FY 1	FY 2
BP-18 FP	$2.80	$2.68
pre BP-20 IP	$1.98	$2.09
Delta	-$0.82	-$0.59



Note. Historical prices sourced S&P Global Platts

Electric Price Forecast

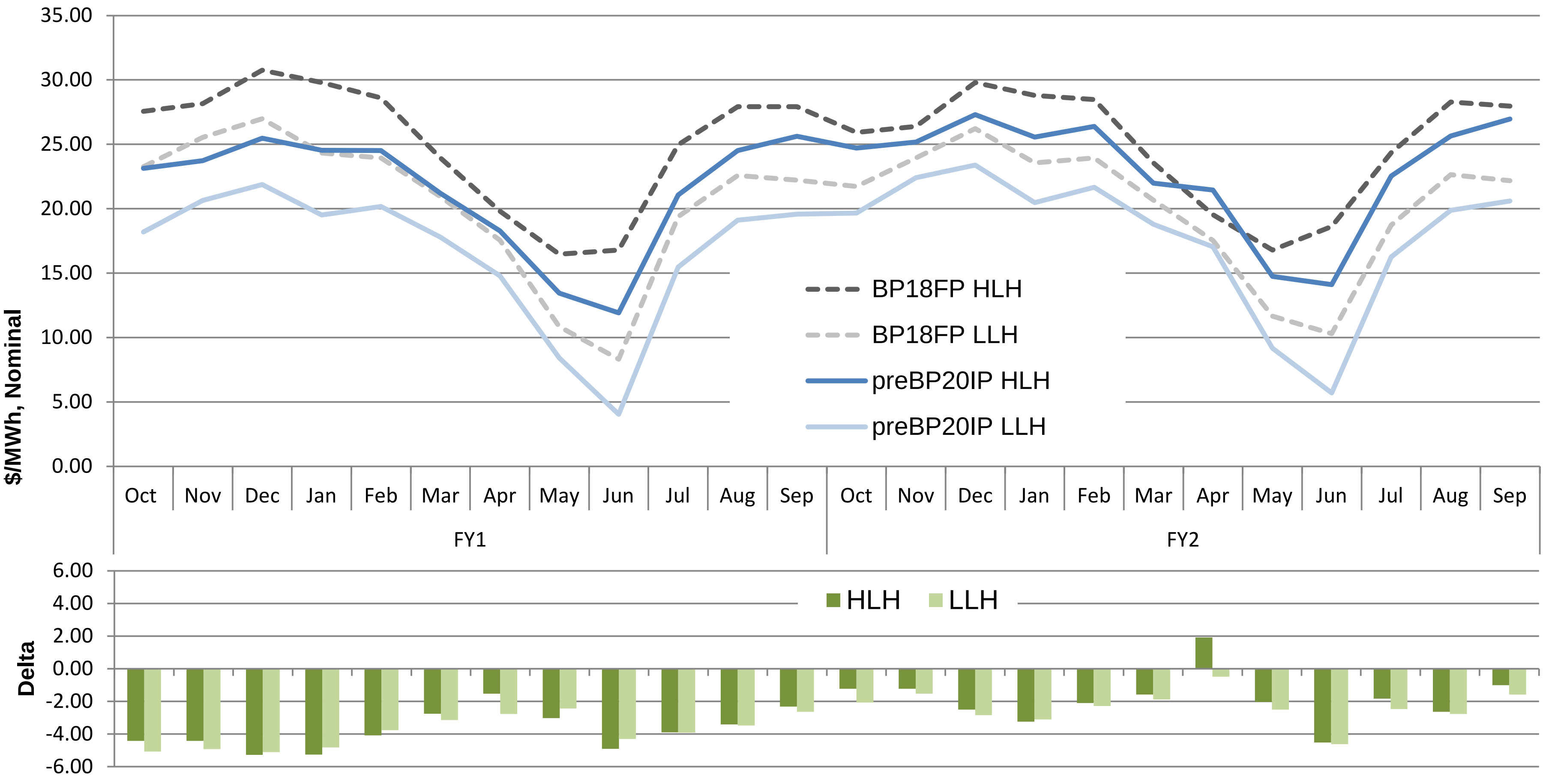
- Continue to rely on AURORA®, using the Western Interconnection topology

Fiscal year and rate case averages for Mid-C:

$/MWh, Nominal	FY1	FY2	**Avg.**
BP18FP	23.14	22.83	22.98
preBP20IP	19.34	20.78	20.06
Delta	-3.79	-2.05	-2.92

- Majority of forecast price changes relative to our BP-18 Final Proposal price forecast are driven by updated natural gas prices, and growth in renewables also continues to put downward pressure on Mid-C prices
- Other modeling updates have moderate price impacts in isolation; in aggregate they tend to net one another out

Average Mid-C Prices
BP-18 FP vs preliminary BP-20 IP



Modeling Changes and Updates Since BP-18 FP

- Updated WECC loads
- New load risk model
- New AURORA® version (v12.3.1064)
- New AURORA® database (DB 2017v3)
  - Fuel adders
  - Resource additions & retirements
  - New hourly wind shapes
- RPS forecast methodology
  - Now employing AURORA® logic to make build decisions and calculate REC price
  - Compensates for expected renewable curtailment
- New hourly NREL solar shapes
- Updated CAISO wind risk model, shifting from NREL estimates to actual hourly patterns
- CA carbon price update
- CA Distributed Generation (DG)* updated
- Desert Southwest DG added
- Alberta RPS added
- Alberta Carbon Tax added
- Now rely on AESO load forecast for Alberta rather than using EPIS
- New solar and wind cost updates (blend of consultant and EPIS estimates consistent with latest Council figures)
- CA storage mandate (~1 GW additional storage added)
- Improved storage logic
- Set nuclear and storage resource variable cost to $0/MWh

* All references to DG are exclusively to rooftop solar

Anticipated Modeling Changes and Updates For BP-20 IP

- Updating natural gas price forecast
- Creating low wheeling price tiers on the COI and PDCI to represent expected low carbon flows to California
- Incorporating further refinements to hourly solar shapes
- Updating historical period for transmission risk model
- Minor updates to hydro shaping parameters

Possible changes to the natural gas price forecast aside, these remaining modeling updates are expected to have cumulative impacts < +/- $1/MWh on average.

Net Secondary Revenue

- Lower natural gas prices combine with other market factors to bring down Mid-C prices in BP-20, as compared to BP-18, thereby decreasing the value of BPA's surplus energy.
- Initial findings indicate significant decreases to BPA's forecast Net Secondary Revenue credit.
  - Preliminary estimates of NSR show a decrease of approximately $90 million on an annual average basis
  - A $66 million decrease is reflective of forecast market conditions
  - Correcting the hydro index error from BP-18 further reduces NSR by $24 million

Net Secondary Revenue

- Staff proposes to set the NSR credit using the mean of the NSR distribution instead of the median.
  - Using the median was implemented in BP-12 due to risk aversion preferences
    - Bonneville had just switched modeling methodologies and decision-makers were very concerned about tail events' impact on the mean, primarily that setting the NSR credit at the mean was forecast to yield a 54% chance of underachieving the NSR credit.
    - By using the median construct, the distribution is truncated, which has the result of excluding influential tail events and, in theory, results in a 50% chance of overachieving and a 50% chance of underachieving the NSR credit.
  - However, using the mean, by definition, will more accurately reflect Bonneville's expected value of NSR than the median.
    - If minimizing the difference between the forecast NSR credit and actual NSR is the goal, the mean is the correct choice of central tendency.
  - In addition, this will eliminate persistent difficulty for staff in calculating the "meandian" (the median construct used in rates) and then reconciling this throughout the year with various analyses that use means.
  - The impact of this switch is expected to be around a $4.5 million decrease per year to the NSR credit in BP-20.

Net Secondary Revenue

- For BP-18, the NSR credit included a premium associated with extra-regional sales made bilaterally into California markets.
- It is proposed to continue modeling extra-regional sales in a manner consistent with BP-18
  - Bonneville may not sell directly into CAISO
    - Sales not made bilaterally are still at risk
      - Costs of transactions may rise
      - Bonneville's ability to transact may be limited or eliminated
    - Due to their uncertain nature, it is proposed the premium associated with these non-bilateral sales continues to be excluded from the NSR credit
  - If BPA receives congressional authorization to purchase carbon allowances and thereby sell directly into CAISO, then the full modeled value of extra-regional sales would be included.

Transfer Service

Derrick Pleger

Jeff Hurt

Dan Yokota

Transfer Service Updates

BPA's Transfer Service group acquires transmission across third party-transmission systems for service to loads outside Bonneville's BAA. The current annual cost to provide this service to all transfer customers is roughly $90 million. The following looks at four separate items that impact Transfer Service customers.

1. Assumptions for the Market Differential for Southeast Idaho loads for the last three months of FY 2021.

2. New Transfer Service Regulation and Frequency Response (RFR) Rate added to the Power GRSPs. For transparency and consistency, billing for RFR service would move from the FPS rate to a new transfer service rate.

3. Updated Estimate of the Transfer Service Delivery Charge (TSDC). The TSDC is recovered through a calculated rate applied to all Transfer Customers who take low voltage service from a third-party transmission provider.

4. WECC Charge.

Market Differential for Southeast Idaho Loads

Last Three Months of FY 2021

Background

- Prior to June, 2016, Southeast Idaho loads were served through an exchange agreement with PacifiCorp.
- Upon termination of the exchange agreement by PacifiCorp at the end of June, 2016, Bonneville entered into two five-year market purchases to service its customers in Southeast Idaho.
- As a result of these purchases, a specific cost was placed into the composite cost pool labeled as Market Differential.
- This budget item makes up a small portion of the overall Transfer Service budget, roughly $5 million annually.
- The Market Differential is the difference between the purchase price of the Market Purchases to serve Southeast Idaho and the forward MID-C ICE Index at the time the Market Purchases were signed.
- The current set of market purchases will terminate on June 30, 2021, leaving the last three months of FY 2021 without a finalized service plan.
- Bonneville will begin finalizing the second interim service plan sometime in 2019 for service beginning July 1, 2021.

Market Differential for Southeast Idaho Loads

Last Three Months of FY 2021

Assumptions to Finish FY 2021

- No renewal of long-term market purchases to serve load needed at this time.
- Local generation combined with current transmission rights and augmented by short-term market purchases are expected to be sufficient to reliably serve Southeast Idaho load during the last three months of FY 2021.
- If through analysis performed during preparations for the second Interim Service Plan, it appears that long-term market purchases may provide a more economic solution than long-term transmission rights, Bonneville will consider that option.
- For the BP-20 initial proposal, BPA proposes to allocate to the Composite Cost Pool a Market Differential of $5.4 million for FY 2020 and $4.2 million for FY 2021 (shown on the following slide).

Market Differential for Southeast Idaho Loads

Last Three Months of FY 2021

	A	B	C	D	E	F	G
	Month	**FY 2016**	**FY 2017**	**FY 2018**	**FY 2019**	**FY 2020**	**FY 2021**
1	October		$ 509,736	$ 509,736	$ 512,140	$ 512,140	$ 512,140
2	November		$ 493,506	$ 493,506	$ 493,506	$ 493,506	$ 491,102
3	December		$ 509,736	$ 507,331	$ 507,331	$ 507,331	$ 509,736
4	January		$ 507,331	$ 509,736	$ 509,736	$ 509,736	$ 507,331
5	February		$ 461,647	$ 461,647	$ 461,647	$ 478,478	$ 461,647
6	March		$ 511,539	$ 511,539	$ 509,135	$ 509,135	$ 511,539
7	April		$ 396,728	$ 396,728	$ 403,942	$ 403,942	$ 403,942
8	May		$ 411,155	$ 411,155	$ 411,155	$ 403,942	$ 403,942
9	June		$ 403,942	$ 403,942	$ 396,728	$ 403,942	$ 403,942
10	July	$ 403,942	$ 403,942	$ 403,942	$ 411,155	$ 411,155	
11	August	$ 418,368	$ 418,368	$ 418,368	$ 418,368	$ 411,155	
12	September	$ 396,728	$ 396,728	$ 389,515	$ 389,515	$ 396,728	
13	FY Total (Sum lines 1-12)	$ 1,219,038	$ 5,424,358	$ 5,417,145	$ 5,424,358	$ 5,441,189	$ 4,205,320
14	5 Year SILS Market Differential Cost						$ 27,131,407

Transfer Service Regulation and Frequency Response (RFR) Rate

Currently, BPA charges transfer customers for RFR under the FPS rate schedule. The rate charged is the same as Transmission Services' RFR rate.

BPA is proposing to add a Transfer Service RFR rate to the Power GRSPs.

- Transfer customers would be charged for RFR under the new rate schedule instead of under the FPS rate schedule.
- The new RFR rate would be the same rate as the Transmission Service RFR rate.
- Similar approach as used for Transfer Service Operating Reserves rates
- Increases consistency and transparency

Transfer Service Delivery Charge

- The Transfer Service Delivery Charge (TSDC) for BP-20 is proposed to be $1.26 per kW-Month.
- Current TSDC is $1.27 per kW-Month
- The slight decrease in the proposed TSDC is due to an increase in loads residing in BAAs with fixed distribution charges rather than a rate.

Transfer Service WECC Charge

- Likely no change, the charge is expected to remain at 0.03 mills/kWh.

- No Reliability Coordinator charges for Transfer Customers.

Next Steps

- By August 22, please send comments on Power rate topics to techforum@bpa.gov.
- Upcoming BP-20 rates workshops are:
  - August 22, 2018 (W)
  - September 12, 2018 (W)