BP-16 Rates Workshop

Power Topics

August 13, 2014

(Revised August 15, 2014)

Agenda

Topic	Presenter
Power Revenue Requirement • Overview • Non-Cash Revenues and MRNR	Alex Lennox, Stephanie Adams
Federal System Resources • Regulated Hydro Forecast • Total Federal System Resource Forecast	Tim Misley, Tyler Llewellyn
Market Update	Peter Williams, Gail Hammer

Power Revenue Requirements

Assumptions

- The BP-16 initial proposal will include:
  - Program costs consistent with the Integrated Program Review (IPR) close out report
  - Capital investments consistent with the Capital in Review (CIR) close out
  - Financing all BPA capital investments with Treasury bonds
  - All completed Federal transactions through July 2014
  - All completed non-Federal transactions including the recently priced Energy Northwest refinancing transaction

- The following tables are consistent with analysis for the May 2014 IPR initial publication and do not reflect the final IPR amounts. They serve as the starting point for the updates described above and later in this presentation that will be applied for the BP-16 Initial Proposal.

Preliminary Income Statement

	($000s)	A 2016	B 2017		C Average	D BP-14 Average
1	OPERATING EXPENSES					
2	POWER SYSTEM GENERATION RESOURCES					
3	OPERATING GENERATION RESOURCES	693,054	756,309		724,681	715,564
4	OPERATING GENERATION SETTLEMENT PAYMENTS	21,863	22,234		22,049	21,656
5	NON-OPERATING GENERATION	1,600	1,863		1,732	2,217
6	CONTRACTED POWER PURCHASES	3,000	3,000	*	3,000	62,668
7	AUGMENTATION POWER PURCHASES	0	0	*	0	50,555
8	EXCHANGES & SETTLEMENTS	278,456	278,436		278,446	278,425
9	RENEWABLE GENERATION	40,987	41,641		41,314	39,223
10	GENERATION CONSERVATION	51,814	44,150		47,982	48,864
11	POWER NON-GENERATION OPERATIONS	97,018	99,836		98,427	93,283
12	PS TRANSMISSION ACQUISITION AND ANCILLARY SERVICES	171,636	183,546	*	177,591	165,121
13	F&W/USF&W/PLANNING COUNCIL	310,539	318,395		314,467	299,153
14	GENERAL AND ADMINISTRATIVE/SHARED SERVICES	75,413	76,854		76,133	74,819
15	OTHER INCOME, EXPENSES AND ADJUSTMENTS	(20,000)	(20,000)		(20,000)	-
16	NON-FEDERAL DEBT SERVICE	571,251	571,933		571,592	478,063
17	DEPRECIATION	145,277	149,981		147,629	130,336
18	AMORTIZATION	88,123	98,824		93,473	96,528
19	TOTAL OPERATING EXPENSES	2,530,030	2,627,003		2,578,516	2,556,473
20						
21	INTEREST EXPENSE:					
22	INTEREST					
23	APPROPRIATED FUNDS	229,810	226,992		228,401	221,481
24	CAPITALIZATION ADJUSTMENT	(45,937)	(45,937)		(45,937)	(45,937)
25	BONDS ISSUED TO U.S. TREASURY	58,303	76,823		67,563	68,444
26	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	0	0		0	0
27	NON-FEDERAL INTEREST	13,273	12,469		12,871	14,408
28	ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION	(6,160)	(4,749)		(5,455)	(11,172)
29	INTEREST CREDIT ON CASH RESERVES	(9,862)	(17,044)		(13,453)	(14,818)
30	NET INTEREST EXPENSE	239,426	248,554		243,990	232,407
31						
32	TOTAL EXPENSES	2,769,456	2,875,557		2,822,506	2,788,880
33						
34	MINIMUM REQUIRED NET REVENUE 1/	3,524	3,524		3,524	0
35	PLANNED NET REVENUE FOR RISK	0	0		0	
36	PLANNED NET REVENUE, TOTAL (30+31)	3,524	3,524		3,524	0
37						
38	**TOTAL REVENUE REQUIREMENT**	**2,772,980**	**2,879,081**		**2,826,031**	**2,788,880**

1/ SEE NOTE ON CASH FLOW STATEMENT

* Costs modeled in the rate case and not yet available

Preliminary Statement of Cash Flows

	($000s)	A 2016	B 2017	C Average	D BP-14 Average
1	CASH FROM OPERATING ACTIVITIES				
2	MINIMUM REQUIRED NET REVENUE 1/	3,524	3,524	3,524	0
3	NON-CASH ITEMS:				
4	NON-FEDERAL INTEREST	13,273	12,469	12,871	14,408
5	DEPRECIATION AND AMORTIZATION	233,400	248,805	241,102	226,864
6	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	0	0	0	-
7	CAPITALIZATION ADJUSTMENT	(45,937)	(45,937)	(45,937)	(45,937)
8	ACCRUAL REVENUES	(34,124)	(34,124)	(34,124)	(34,124)
9	CASH PROVIDED BY OPERATING ACTIVITIES	170,136	184,737	177,436	161,211
10					
11	CASH FROM INVESTMENT ACTIVITIES:				
12	INVESTMENT IN:				
13	UTILITY PLANT (INCLUDING AFUDC)	(351,514)	(343,885)	(347,700)	(337,602)
14	ENERGY EFFICIENCY	(94,800)	(97,600)	(96,200)	(83,600)
15	FISH & WILDLIFE	(54,807)	(30,795)	(42,801)	(55,780)
16	CASH USED FOR INVESTMENT ACTIVITIES	(501,122)	(472,279)	(486,701)	(476,981)
17					
18	CASH FROM BORROWING AND APPROPRIATIONS:				
19	INCREASE IN BONDS ISSUED TO U.S. TREASURY	405,902	410,347	408,125	259,095
20	REPAYMENT OF BONDS ISSUED TO U.S. TREASURY	(10,500)	(35,150)	(22,825)	(70,881)
21	INCREASE IN FEDERAL CONSTRUCTION APPROPRIATIONS	95,220	61,932	78,576	91,142
22	REPAYMENT OF FEDERAL CONSTRUCTION APPROPRIATIONS	(98,682)	(98,196)	(98,439)	(38,000)
23	CUSTOMER PROCEEDS	0	0	0	126,745
24	PAYMENT OF IRRIGATION ASSISTANCE	(60,954)	(51,391)	(56,172)	(52,330)
25	CASH PROVIDED BY BORROWING AND APPROPRIATIONS	330,986	287,543	309,265	315,770
26					
27	ANNUAL INCREASE (DECREASE) IN CASH	0	0	0	0
28					
29	PLANNED NET REVENUE FOR RISK	0	0	0	-
30					
31	TOTAL ANNUAL INCREASE (DECREASE) IN CASH	0	0	0	0

1/ Line 30 must be greater than or equal to zero to indicate that cash cost recovery requirements are being achieved. If not, net revenues (MRNR) are added so that net cash flows for the year (Line 30) are zero.

Pre-Decisional. For Discussion Purposes Only.

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REVISED August 15, 2014

But what about …

- BPA is proposing to treat the following items in the BP-16 initial proposal as described below.

- Energy Northwest Regional Cooperation Debt Refinancing:
  - As with Debt Optimization in the past, we do not intend to model forecasted refinancing transactions in the repayment study.
  - We do intend to include a forecast of the net effect of the changes to non-Federal debt service, net interest, and MRNR in the revenue requirement. Our current plan is to incorporate the effect as an undistributed reduction.

- EE Post-2011 Review
  - BPA has not issued a decision on proposed revisions.
  - After considering public comments, BPA will make a final decision, update the Implementation Program, and prepare for the implementation of the changes.
  - If adopted, implementation of Billing Credits and the Large Project Program revisions would be modelled in BP-16 when participation in these programs is known.

But what about …

EE Post-2011 Review (continued)

- Billing Credits
  - We do not expect to include a forecast of participation in the Initial Proposal.
  - We will make modifications to the modeling to accommodate this program in the event there are participants in the future.
    - The Cost Table will have a new line for the billing credit cost.
    - As participants are added, the costs associated with borrowing for the EEI program will decline as the billing credit costs accrue.
    - By definition, billing credits cannot cost BPA more than the status quo.

- Large Project Program
  - We do not expect to include a forecast of participation in the Initial Proposal.
  - The cost of each project will be matched with a targeted rate adjustment for the participating utility, shielding other customers from the costs of these projects.

Non-Cash Revenues & MRNR

- In 1998, BPA and PGE entered into a settlement of a power exchange contract that arose out of the decision to terminate the WNP-3 nuclear plant.
- PGE paid $74 million to BPA. The revenue impact of this payment has been recognized at the rate of $3.524 million per year. The settlement will be fully amortized in FY 2019.
- The $74 million payment is a factor in the calculation of the Power financial reserves balance as of the end of FY 2001. The balance would have been lower if not for the PGE payment. This balance is used in the calculation of the interest credit for the composite cost pool.
- These revenues appear in the credit section of the revenue forecast used in the rate case. They are credited to the composite cost pool. Credits have the effect of reducing rates.
- As a non-cash item, these revenues appear in the Power revenue requirement statement of cash flows and are factored into the calculation of Minimum Required Net Revenues (MRNR). This ensures that revenues from proposed rates provide sufficient cash flows for the cost recovery demonstration.
- In the Tiered Rate Methodology Non-Slice cost pool table, there is a line labeled “Accrual Revenues” that can be used for non-cash revenues. In BP-12 and BP-14, the PGE settlement revenues were allocated to the non-Slice cost pool using this line. We do not believe that this interpretation is appropriate. These revenues result from a settlement that occurred before the Slice product and, therefore, the revenues and any consequent cost is attributable to all power customers, not just Non-Slice.

Why Not Assign to the Non-Slice Cost Pool?

- In BP-14, the amortization of Federal debt was set to equal the sum of the non-cash elements of Power's revenue requirement, including the non-cash revenue associated with the PGE settlement. This was done to avoid the Anticipated Accumulation of Cash (AAC) which would have resulted in Slice customers contributing to BPA reserves. As a result, for Power as a whole, MRNR was zero and cash flow was zero for the rate period. We plan on taking the same approach to BP-16.
- The allocation of the PGE settlement to the Non-Slice cost pool would produce the following results.
  - The accrual revenues represent negative cash flow for the Non-Slice cost pool. MRNR of $3.524 million, equal to the accrual revenue, would be added to eliminate the negative cash flow. This would result in a charge to non-Slice customers of $3.524 million.
  - For the Composite cost pool, MRNR would be zero. This occurs because the Federal amortization payments are set to equal the sum of the non-cash elements. Excluding the PGE settlement would disrupt that balance resulting in positive cash flow in the Composite cost pool, equal to the accrual revenue, which would be counter to the reason for setting MRNR at zero in the first place. This means that, all else being equal, Slice customers would contribute to financial reserves because MRNR is never negative. It is set at zero when there is positive cash flow.
  - The Composite cost pool further would receive a credit for the MRNR collected in the Non-Slice rate.
  - This disparity will continue through the remaining life of the PGE settlement if the accrual revenues are assigned to the Non-Slice cost pool.

MRNR Calculation

				A
	($000s)			2014 Total
1	CASH FROM OPERATING ACTIVITIES			
2		MINIMUM REQUIRED NET REVENUE 1/		-
3		NON-CASH ITEMS:		
4			NON-FEDERAL INTEREST	14,775
5			DEPRECIATION AND AMORTIZATION	224,447
6			CAPITALIZATION ADJUSTMENT	(45,937)
7			**ACCRUAL REVENUES**	**(34,124)**
8	CASH PROVIDED BY OPERATING ACTIVITIES			159,161
9	CASH FROM INVESTMENT ACTIVITIES:			
10		INVESTMENT IN:		
11			UTILITY PLANT (INCLUDING AFUDC)	(390,279)
12			ENERGY EFFICIENCY	(75,200)
13			FISH & WILDLIFE	(60,275)
14	CASH USED FOR INVESTMENT ACTIVITIES			(525,754)
15	CASH FROM BORROWING AND APPROPRIATIONS:			
16		INCREASE IN BONDS ISSUED TO U.S. TREASURY		223,850
17		REPAYMENT OF BONDS ISSUED TO U.S. TREASURY		(30,611)
18		INCREASE IN FEDERAL CONSTRUCTION APPROPRIATIONS		143,303
19		REPAYMENT OF FEDERAL CONSTRUCTION APPROPRIATIONS		(76,000)
20		CUSTOMER PROCEEDS		158,601
21		PAYMENT OF IRRIGATION ASSISTANCE		(52,550)
22	CASH PROVIDED BY BORROWING AND APPROPRIATIONS			366,593
23	ANNUAL INCREASE (DECREASE) IN CASH			0

Includes $3.524 million for PGE Settlement

View by Cost Pool

	The Problem			
		A	B	C
	($000s)	2014 Total	Composite Cost Pool	Non-Slice Cost Pool
1	CASH FROM OPERATING ACTIVITIES			
2	MINIMUM REQUIRED NET REVENUE 1/	-	-	**3,524**
3	NON-CASH ITEMS:			
4	NON-FEDERAL INTEREST	14,775	14,775	-
5	DEPRECIATION AND AMORTIZATION	224,447	224,447	-
6	CAPITALIZATION ADJUSTMENT	(45,937)	(45,937)	-
7	**ACCRUAL REVENUES**	**(34,124)**	**(30,600)**	**(3,524)**
8	CASH PROVIDED BY OPERATING ACTIVITIES	159,161	162,685	-
9	CASH FROM INVESTMENT ACTIVITIES:			
10	INVESTMENT IN:			
11	UTILITY PLANT (INCLUDING AFUDC)	(390,279)	(390,279)	-
12	ENERGY EFFICIENCY	(75,200)	(75,200)	-
13	FISH & WILDLIFE	(60,275)	(60,275)	-
14	CASH USED FOR INVESTMENT ACTIVITIES	(525,754)	(525,754)	-
15	CASH FROM BORROWING AND APPROPRIATIONS:			
16	INCREASE IN BONDS ISSUED TO U.S. TREASURY	223,850	223,850	-
17	REPAYMENT OF BONDS ISSUED TO U.S. TREASURY	(30,611)	(30,611)	-
18	INCREASE IN FEDERAL CONSTRUCTION APPROPRIATIONS	143,303	143,303	-
19	REPAYMENT OF FEDERAL CONSTRUCTION APPROPRIATIONS	(76,000)	(76,000)	-
20	CUSTOMER PROCEEDS	158,601	158,601	-
21	PAYMENT OF IRRIGATION ASSISTANCE	(52,550)	(52,550)	-
22	CASH PROVIDED BY BORROWING AND APPROPRIATIONS	366,593	366,593	-
23	ANNUAL INCREASE (DECREASE) IN CASH	-	3,524	-
24	**Slice effect = contribution to reserves**		**952**	

Pre-Decisional. For Discussion Purposes Only.

Proposed Solution

- We propose to set principal payments to equal the sum of the non-cash elements of the revenue requirement, as we did in BP-14. On a forecast basis, this will set MRNR at zero and cash flow at zero.

- In the cost allocation, we propose to treat the non-cash revenues as a composite cost pool cost instead of as a non-Slice cost. Since the composite cost pool receives all of the benefit of the 1998 PGE settlement, it should bear the cost of the settlement as well.

- We believe this treatment is consistent with Cost Allocation Principle

  #2 – Costs not otherwise expressly allocated in the TRM will be allocated to Cost Pools based on the principle of cost causation, meaning the costs will be allocated to the Cost Pool(s) that benefits from such costs.

Effect of the Correction -- View by Cost Pool

		A	B	C
	($000s)	2014 Total	Composite Cost Pool	Non-Slice Cost Pool
1	CASH FROM OPERATING ACTIVITIES			
2	**MINIMUM REQUIRED NET REVENUE 1/**	**-**	**-**	**-**
3	NON-CASH ITEMS:			
4	NON-FEDERAL INTEREST	14,775	14,775	-
5	DEPRECIATION AND AMORTIZATION	224,447	224,447	-
6	CAPITALIZATION ADJUSTMENT	(45,937)	(45,937)	-
7	**ACCRUAL REVENUES**	**(34,124)**	**(34,124)**	**-**
8	CASH PROVIDED BY OPERATING ACTIVITIES	159,161	159,161	-
9	CASH FROM INVESTMENT ACTIVITIES:			
10	INVESTMENT IN:			
11	UTILITY PLANT (INCLUDING AFUDC)	(390,279)	(390,279)	-
12	ENERGY EFFICIENCY	(75,200)	(75,200)	-
13	FISH & WILDLIFE	(60,275)	(60,275)	-
14	CASH USED FOR INVESTMENT ACTIVITIES	(525,754)	(525,754)	-
15	CASH FROM BORROWING AND APPROPRIATIONS:			
16	INCREASE IN BONDS ISSUED TO U.S. TREASURY	223,850	223,850	-
17	REPAYMENT OF BONDS ISSUED TO U.S. TREASURY	(30,611)	(30,611)	-
18	INCREASE IN FEDERAL CONSTRUCTION APPROPRIATIONS	143,303	143,303	-
19	REPAYMENT OF FEDERAL CONSTRUCTION APPROPRIATIONS	(76,000)	(76,000)	-
20	CUSTOMER PROCEEDS	158,601	158,601	-
21	PAYMENT OF IRRIGATION ASSISTANCE	(52,550)	(52,550)	-
22	CASH PROVIDED BY BORROWING AND APPROPRIATIONS	366,593	366,593	-
23	ANNUAL INCREASE (DECREASE) IN CASH	-	-	-
24	**Slice effect = contribution to reserves**		-	

Federal System Resources

Regulated Hydro Forecast

Updates to HYDSIM Assumptions in the BP-16 Preliminary Hydro Forecasts

- **Canadian operations** were updated based on the 2016 Assured Operating Plan (Treaty AOP study). AOP17 is a roll-over year. Non-Treaty operations were also updated, similar to BP-14, with the dry year operation and the spring-summer operation. The price-dependent operations from the Non-Treaty Storage Agreement and the Libby Coordination Agreement were not included. In these studies, Canadian projects release less water during 1937.
- **Spill assumptions** were updated based on the 2014 Biological Opinion as shown on the following slide. These assumptions better reflect actual operations from the past few years, and changes are not expected within the rate period.
- **2014 PNCA project data** is used in these studies. The last Rate Case studies were based on 2012 PNCA data. This data includes minor flow requirement and elevation target changes.
- **80-year flood control data** was provided by the Corps. This data is based on the 2010 modified stream flow data and associated forecasts. In the last Rate Case, the Corps provided interim flood control data for the last 10 years of the 80-year HYDSIM studies, and the studies used older data for the first 70 years.
- **Monthly outage assumptions** were developed using a combination of planned outages plus forced outages that are based on historical data, and the project owners also made further adjustments. Using the new method, most projects have similar levels of outages compared to BP-14, but Grand Coulee availability increased several percent to ~70% on average.
- **Reserves** were provided by the Generation Inputs panel.
- **Loads** were updated based on data provided by Agency Load Forecasting. HYDSIM uses regional residual hydro loads in the Rate Case, so assumptions for other resources also affect the loads in HYDSIM. The new HYDSIM loads are about 2000 aMW lower than in BP-14. This reduction is mainly because of the new combustion turbine capacity factor assumption of 90%.

Updates to HYDSIM Assumptions
Spill Table from 2014 BiOp

Project	Proposed 2014 BiOp Spring Spill	Spring Planning Dates	Proposed 2014 BiOp Summer Spill	Summer Planning Dates
Bonneville	100 kcfs	4/10 - 6/15	95 kcfs and 85 kcfs/121 kcfs	6/16 - 8/31
The Dalles	40%	4/10 - 6/15	40%	6/16 - 8/31
John Day	April 10-27: 30% April 27-June 15: 30% and 40%	4/10 - 6/15	June 16-July 20: 30% and 40% July 20-August 31: 30%	6/16 - 8/31
McNary	40%	4/10 - 6/15	50%	6/16 - 8/31
Ice Harbor	April 3-28: 45 kcfs/Gas Cap April 28-May 30: 30% and 45 kcfs/Gas Cap	4/3 - 5/31	June 1-July 13: 30% and 45 kcfs/Gas Cap June 13-August 31: 45 kcfs/Gas Cap	6/1 - 8/31* (8/21)
Lower Monumental	Gas Cap (~27 kcfs, bulk pattern)	4/3 - 5/31	17 kcfs	6/1 - 8/31* (8/19)
Little Goose	30%	4/3 - 5/31	30%	6/1 - 8/31* (8/17)
Lower Granite	20 kcfs	4/3 - 5/31	18 kcfs	6/1 - 8/31* (8/9)

* The Snake River projects end spill in August based on fish passage data. The end dates used in HYDSIM are based on the averages from 2005 through 2013 data.

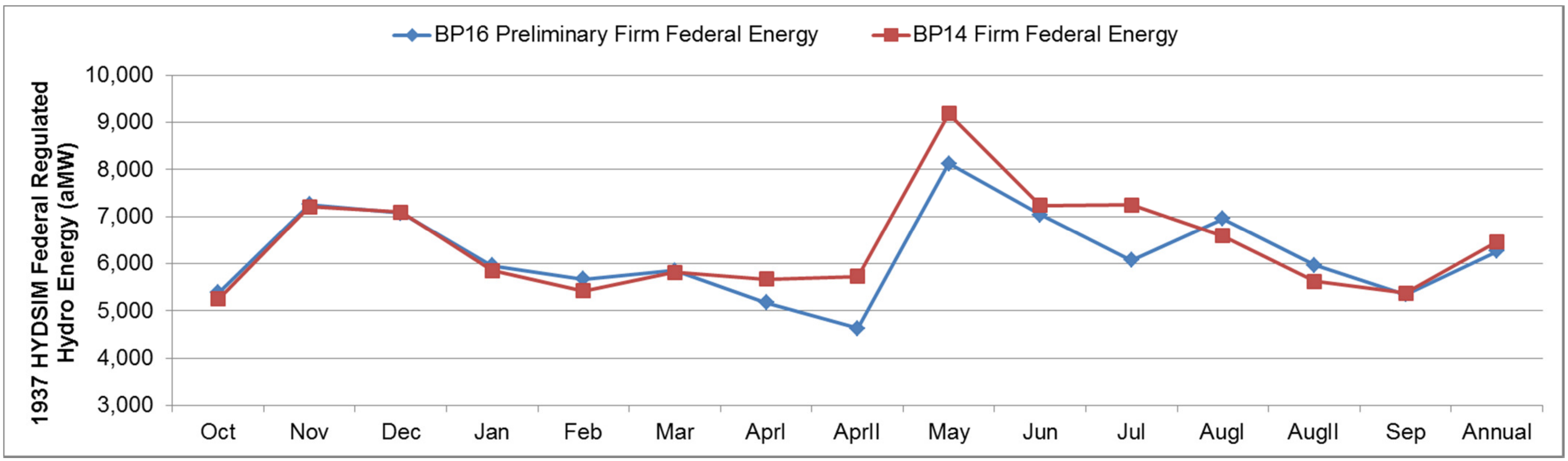
Spring maximum transport operations for two weeks in all years and in dry years are not in the 2014 Biological Opinion.

HYDSIM Results from BP-16 Preliminary Hydro Forecasts Firm Energy

- The new estimate of firm average annual regulated hydro energy is 200 aMW lower than the last Rate Case.
- This loss is primarily caused by the increased spill for fish and the decreased stream flow releases from Canadian projects in 1937.

Firm Federal Regulated Hydro Energy (Average MW)

1937	Oct	Nov	Dec	Jan	Feb	Mar	AprI	AprII	May	Jun	Jul	AugI	AugII	Sep	Annual
BP16 Preliminary	5,379	7,258	7,072	5,953	5,669	5,849	5,173	4,632	8,122	7,036	6,073	6,948	5,961	5,348	6,265
BP14	5,246	7,211	7,095	5,846	5,425	5,813	5,673	5,726	9,188	7,239	7,244	6,585	5,624	5,371	6,465
difference	133	47	-23	107	244	35	-499	-1,094	-1,066	-203	-1,171	363	337	-23	-200

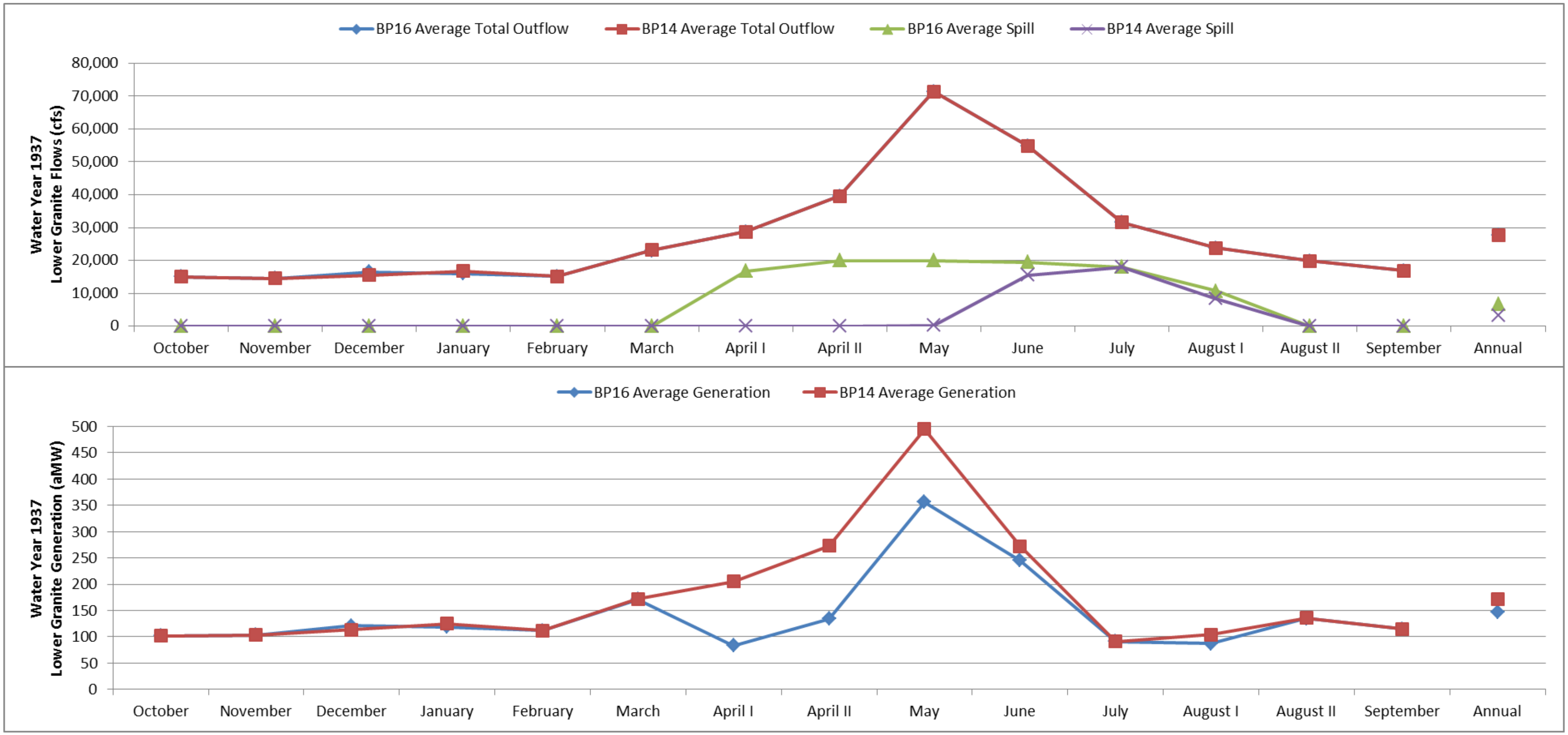


Differences in Firm Federal Regulated Hydro Energy from BP-14 Final to BP-16 Preliminary Hydro Forecasts

- The HYDSIM average annual regulated hydro energy under 1937 water conditions is forecast as 200 aMW lower in the BP-16 Preliminary studies than the last Rate Case.
- This reduction is primarily caused by changes in spill assumptions and decreased stream flow releases from Canadian projects in 1937, the impacts of which are summarized below.
  - Changes in spill assumptions: Generation reduced a total of ~140 aMW.
    - Lower Granite: Generation reduced ~25 aMW.
    - Little Goose: Generation reduced ~20 aMW.
    - Lower Monumental: Generation reduced ~30 aMW.
    - Ice Harbor: Generation reduced ~50 aMW.
    - John Day: Generation reduced ~15 aMW.
  - Decreased stream flow releases from Canadian projects: Generation reduced a total of ~60 aMW.
    - Grand Coulee: Generation reduced ~20 aMW.
    - Chief Joseph: Generation reduced ~20 aMW.
    - Lower Columbia: Generation reduced ~20 aMW total, with the reduction distributed relatively evenly across the four projects (McNary, John Day, The Dalles, Bonneville).
- Monthly differences vary significantly from the annual averages described above for several reasons.
- The next few slides illustrate how different factors impact the monthly regulated hydro shape.

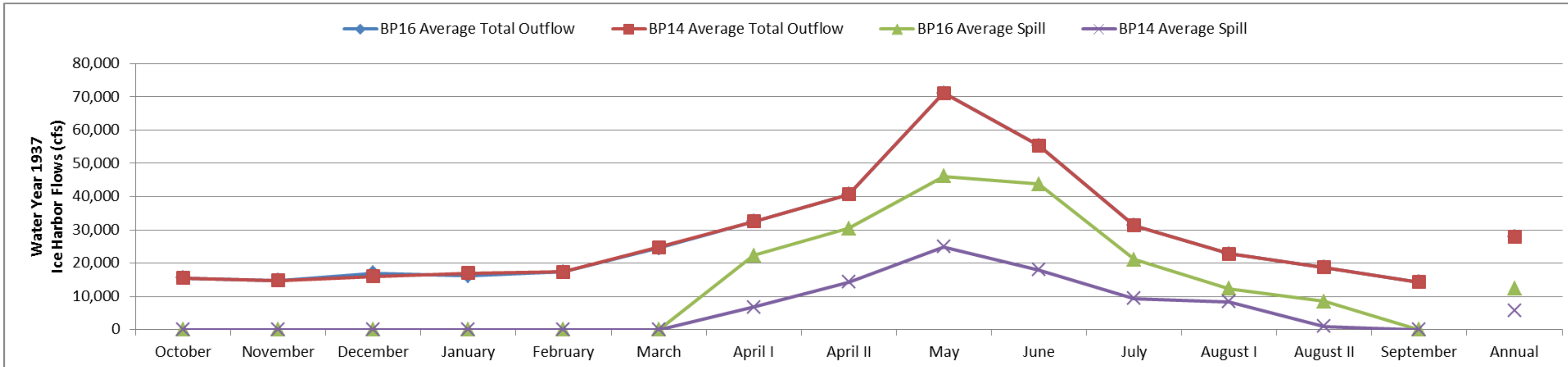
Change in Lower Granite Generation Under 1937 Water Conditions

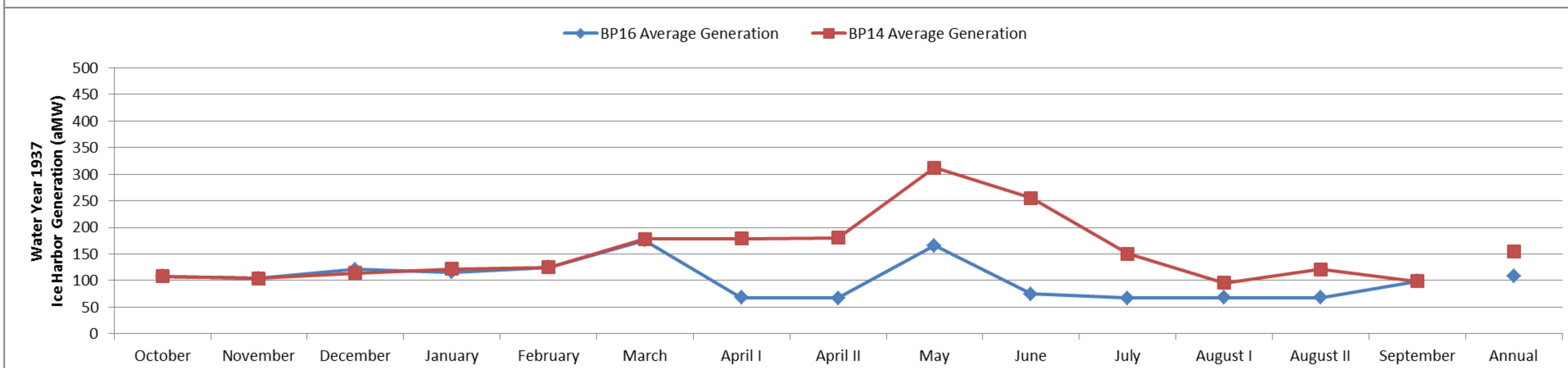
- While Lower Granite's monthly outflow is nearly the same, more spill in some periods results in less generation.
- Most of the changes in generation are due to not including the Spring Maximum Transport in Dry Years operation, which increases spill from April through June.
- Generation is reduced a smaller amount in August due to the updated August spill end dates.



Change in Ice Harbor Generation Under 1937 Water Conditions

- Similar to Lower Granite, Ice Harbor's monthly outflow is nearly the same in the BP-16 studies, but more spill in the spring and summer results in less generation.
- Most of the changes in generation are due to assuming the spill test operations in the 2014 BiOp spill table.



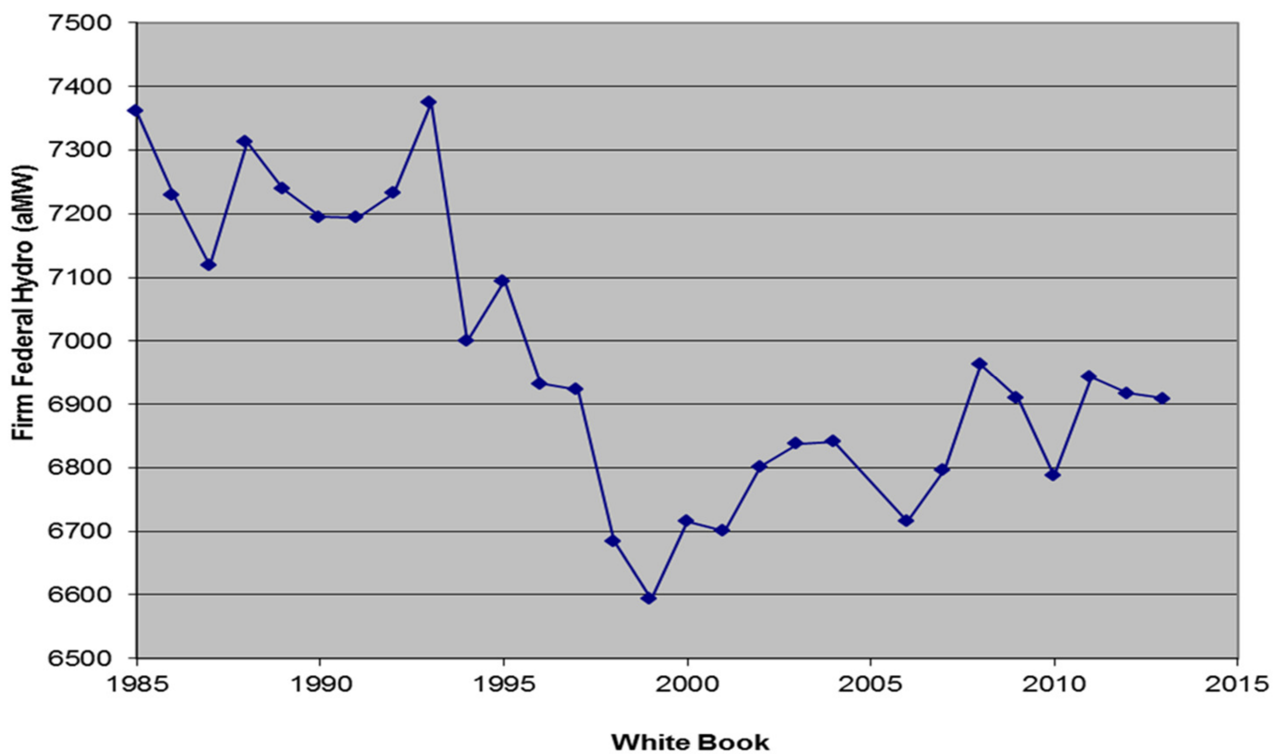


Primary Drivers of Monthly Federal Generation Differences Under 1937 Water Conditions

- **April II (Second Half of April)**
  - Changes in spill at the Lower Snake projects & John Day reduces their generation. These spill changes include not modeling the Spring Maximum Transport in Dry Years operation as well as assuming the test operations shown in the 2014 BiOp spill table for Ice Harbor & John Day.
  - In the current studies, Albeni Falls operates to a lower winter elevation than in the previous Rate Case, resulting in additional fill at Albeni Falls in April that reduces its outflow. This, along with passed through flow changes from Kerr in April, reduces generation at all downstream projects (Grand Coulee – Bonneville).
- **May**
  - Changes in spill at the Lower Snake projects & John Day reduces their generation due to the same reasons listed above under April II.
  - Delayed sturgeon pulse start from mid-May to June 1st at Libby reduces its generation and outflow in May. The passed through flow change from Libby combined with less outflow from Canadian projects reduces generation at all downstream projects (Grand Coulee – Bonneville).
- **June**
  - Changes in spill at the Lower Snake projects & John Day reduces their generation due to the same reasons listed above under April II. However, the generation reductions at Lower Snake transport projects are not as large because these projects transition to summer spill in June, so the previous Rate Case included some spill for these projects.
  - Delayed sturgeon pulse start from mid-May to June 1st at Libby increases its generation and outflow in June. The passed through flow change from Libby partially offsets the lower outflow from Canadian projects.
- **July**
  - Changes in spill at Ice Harbor & John Day reduces their generation. These spill changes are due to assuming the test operations shown in the 2014 BiOp spill table.
  - Substantial decrease in outflow from Canada reduces generation at all downstream projects.

Historical Estimates of Firm Federal Hydro Generation

- Historically BPA's estimates of firm hydro generation have changed +/-200 MW for many reasons that are generally beyond BPA's control, such as: changes in load, changes in operations for fish, revisions to Canadian operations, updates to flood control rule curves, and updates in PNCA planning data. These changes will continue to occur in future studies.

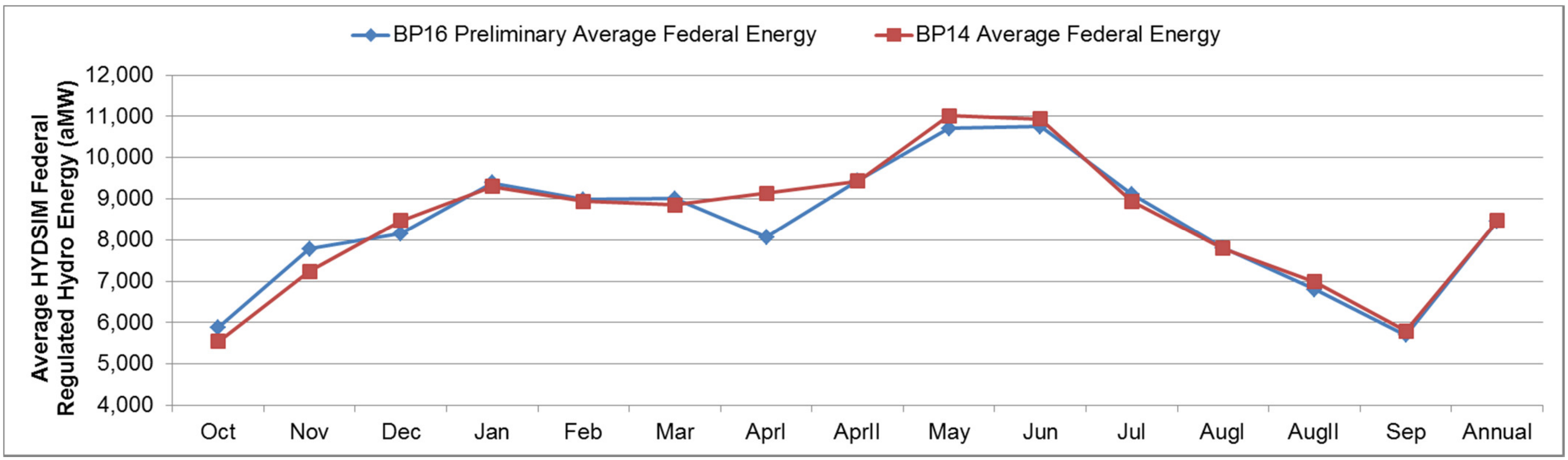


HYDSIM Results from BP-16 Preliminary Hydro Forecasts Average Energy

- The new estimate of the 80-year average annual regulated hydro energy is 14 aMW lower than the last Rate Case.
- This loss is primarily caused by the increased spill for fish and is mostly offset by increased generation at Grand Coulee due to the increased availability estimates and flattened April – July releases.

Average Federal Regulated Hydro Energy (Average MW)

80-Year Average	Oct	Nov	Dec	Jan	Feb	Mar	AprI	AprII	May	Jun	Jul	AugI	AugII	Sep	Annual
BP16 Preliminary	5,884	7,780	8,151	9,382	8,979	9,003	8,065	9,441	10,702	10,750	9,118	7,802	6,800	5,696	8,455
BP14	5,544	7,233	8,465	9,301	8,937	8,846	9,131	9,434	11,011	10,938	8,935	7,788	6,984	5,789	8,469
difference	340	547	-314	82	42	158	-1,067	7	-309	-189	184	14	-184	-92	-14



Federal System Resources

Total Federal System Resource Forecast

BP-16 Preliminary Federal Resource Forecast

BP-16 Preliminary Resource Forecast Assumptions for FY2016-17 Compared to BP-14 Final Rate Case

- Updated HYDSIM hydro regulation studies that decreased the 2-year averaged regulated hydro generation by about 202 aMW under 1937 critical water conditions and about 13 aMW under the 2-year averaged 80 water conditions.

- Updated CGS generation and maintenance schedule to reflect recent work at the project. This increased CGS 2-year averaged generation estimates for FY16 & FY17 by about 42 aMW.

- The expiration of the Georgia-Pacific (Wauna) acquisition contract on 3/31/2016. This decreased the 2-year averaged generation estimates for FY16 & FY17 by about 14 aMW.

- Contract purchases:
  - Update to BPA/BCHA LCA receipts decreased over the 2-year average for FY16 & FY17 by 2 aMW
  - Expiration of BPA/PASA contract receipts that expire 4/30/2015 decreased over the 2-year average for FY16 & FY17 by 5 aMW
  - Expiration of BPA/RVSD contract receipts that expire 4/30/2016 decreased over the 2-year average for FY16 & FY17 by 11 aMW
  - Expiration of BPA/PAC SNX receipts 11/30/2013 decreased over the 2-year average for FY16 & FY17 by 7 aMW.
  - Contract differences of the Non-Federal Canadian Entitlement to BPA-P over the 2-year average for FY16 & FY 17 increased by 1 aMW
  - The calculated Slice Tx Loss Return decreased over the 2-year average for FY16 & FY17 by 1 aMW

- Updated Transmission and Distribution loss factors for energy (2.97%) and peak (3.38%) which increased Federal Transmission Losses by about 12 aMW under 1937 critical water conditions and about 20 aMW under the averaged 80 water conditions.

- Updated critical Wind forecasts which had minimal impacts in wind generation forecasts.

BP-16 Preliminary Federal Resource Forecast

BP-16 Preliminary versus BP-14 Final Proposal for 1937 Critical Water Conditions [1/]

2-Year Average Comparison BP-16 Final and BP-14 Final *(Energy in aMW)*	BP-16 Prelim Study	BP-14 Final Proposal	Difference 2-Year Average	Comment
Federal Resources				
1. Net Hydro Resources	6,664	6,866	-201	Changes in spill criteria on Lower Snake projects in the 2014 BiOp Implementation Plan that highlights splill even in low water conditions
2. Other Resources	1,064	1,036	28	Resource changes: CGS (+42 aMW), GP-Paper (Wauna) (-14 aMW)
3. Contract Purchases	238	263	-25	BPA/BCHA LCA (-1 aMW), Expiration of BPA/PASA contract 4/30/2015 (-6 aMW), BPA/RVSD contract 4/30/2016 (-11 aMW), BPA/PAC SNX (-7 aMW), Canadian Return NFD (+1 aMW), Slice Tx Loss Return (-1 aMW)
4. Reserves and Tx Losses	-247	-235	-12	Change in total resources and updated Federal Tx loss factor from 2.82% to 2.97% (-12 aMW)
5. Total Federal Resources	**7,719**	**7,930**	**-210**	

[1/] Note: Total Federal Resources are not adjusted for Slice Resource Obligations and do not contain Augmentation. Though some of the Total Federal Resources components are included in the RHWM calculations, the results are not directly comparable because the RHWM calculation incorporates specified resources plus contract purchases, which are reduced by specified contract obligations. (RHWM is a subset of Federal Resources.)

BP-16 Preliminary Federal Resource Forecast

BP-16 Preliminary versus BP-14 Final Proposal for the Averaged 80 Water Conditions [1/]

2-Year Average Comparison BP-16 Final BP-14 Final *(Energy in aMW)*	BP-16 Prelim Study	BP-14 Final Proposal	Difference 2-Year Average	Comment
Federal Resources				
1. Net Hydro Resources	8,909	8,922	-13	Changes in spill criteria on Lower Snake projects in the 2014 BiOp Implementation Plan that highlights splill even in low water conditions
2. Other Resources	1,064	1,036	28	Resource changes: CGS (+42 aMW), GP-Paper (Wauna) (-14 aMW)
3. Contract Purchases	238	263	-25	BPA/BCHA LCA (-1 aMW), Expiration of BPA/PASA contract 4/30/2015 (-6 aMW), BPA/RVSD contract 4/30/2016 (-11 aMW), BPA/PAC SNX (-7 aMW), Canadian Return NFD (+1 aMW), Slice Tx Loss Return (-1 aMW)
4. Reserves and Tx Losses	-313	-293	-20	Change in total resources and updated Federal Tx loss factor from 2.82% to 2.97% (-20 aMW)
5. Total Federal Resources	**9,897**	**9,928**	**-31**	

[1/] Note: Total Federal Resources are not adjusted for Slice Resource Obligations and do not contain Augmentation. Though some of the Total Federal Resources components are included in the RHWM calculations, the results are not directly comparable because the RHWM calculation incorporates specified resources plus contract purchases, which are reduced by specified contract obligations. (RHWM is a subset of Federal Resources.)

Appendix
Updates to HYDSIM Spill Assumptions

- **John Day & Ice Harbor Spill**: These operations will eventually be determined based on BiOp juvenile dam passage survival performance standards, but this will not likely occur before the rate period. Current HYDSIM study includes the test operations shown in the 2014 BiOp spill table.
- **Early August Spill Curtailment**: This operation is in the 2014 BiOp. Current HYDSIM study includes this spill assumption similar to the last Rate Case studies but updated to reflect August spill end dates provided by the Corps last fall.
- **Spring Maximum Transport for 2 Weeks in All Years**: This operation is not in the 2014 BiOp. Current HYDSIM study removes this no-spill assumption.
- **Spring Maximum Transport in Dry Years**: This operation is not in the 2014 BiOp. Current HYDSIM study removes this no-spill assumption.
- **April Spill Start Dates at Snake River Projects**: The operation in the 2014 BiOp shows April 3rd, but the last Rate Case study used April 5th at Little Goose and April 7th at Lower Monumental and Ice Harbor. Current HYDSIM study starts spill April 3rd.

Appendix
HYDSIM Results from BP-16 Preliminary Hydro Forecasts

- **<u>Grand Coulee</u>**
  - 1937: Generation reduced ~20 aMW, mostly due to reductions in Canadian releases. The Grand Coulee generation reduces in April-July, and this is mostly offset by gains in August-November and January-March.
  - 80-Year Average: Generation increased ~60 aMW mostly due to the new availability estimates, which are greater than the previous Rate Case and reduced forced spill. Also the flood control and average elevations are slightly higher, which allows more generation.
- **<u>Chief Joseph</u>**
  - 1937: Generation reduced ~20 aMW, mostly due to reductions in Canadian releases. The Chief Joseph generation reduces in April-July, and this is mostly offset by gains in August-November and January-March.
  - 80-Year Average: Generation increased ~30 aMW mostly due to the flatter shape of spring flows which reduced forced spill.
- **<u>Lower Snake</u>**
  - 1937: Generation reduced ~120 aMW due to spill changes.
  - 80-Year Average: Generation reduced ~80 aMW due to spill changes.
- **<u>Lower Columbia</u>**
  - 1937: Generation reduced ~30 aMW due to reductions in Canadian releases and due to spill changes.
  - 80-Year Average: Generation decreased ~20 aMW due to combined stream flow and spill changes.

Appendix
HYDSIM Results from BP-16 Preliminary Hydro Forecasts (cont.)

- **Libby**
  - 1937: Annual average generation is unchanged, but Libby produces less energy in May and more in June due to the delayed sturgeon pulse start from mid-May to June 1st.
  - 80-Year Average: Annual average generation is unchanged, but Libby produces more energy January-March because we removed the Corra Linn flood-reduction logic, and more energy in June because we delayed the sturgeon pulse start from mid-May to June 1st in all years.
- **Hungry Horse**
  - 1937: No changes to generation.
  - 80-Year Average: Annual average generation is unchanged, but there are small increases March-May and a decrease in June due to flood control changes.
- **Albeni Falls**
  - 1937: Annual average generation is unchanged.
  - 80-Year Average: Annual average energy reduced ~2 aMW due to changed Albeni Falls' winter elevation (increased November outflow and decreased April outflow) and passed through flow changes from Kerr (Flathead Lake).
- **Dworshak**
  - 1937: No changes to generation.
  - 80-Year Average: Annual average energy reduced ~3 aMW, small changes on monthly averages, but some years change significantly due to the new flood control URCs.

Appendix
BP-16 Preliminary Federal Resource Forecast

BP-16 Preliminary versus BP-14 Final Proposal Components for 1937 Critical Water Conditions

	2-Year Average Comparison BP-16 Final BP-14 Final *(Energy in aMW)*	BP-16 Prelim Study	BP-14 Final Proposal	Difference 2-Year Average
1	**Net Hydro**	**6,664.4**	**6,865.9**	**-201.5**
2	Regulated Hydro - Net	6,311.3	6,512.5	-201.2
3	Independent Hydro - Net	353.1	353.4	-0.3
4	**Other Resources**	**1,064.0**	**1,036.2**	**27.9**
5	Cogeneration Resources	5.4	19.2	-13.8
6	Combustion Turbines	0.0	0.0	0.0
7	Large Thermal Resources	995.6	953.8	41.8
8	Renewable Resources	60.1	60.3	-0.2
9	Small Hydro Resources	2.9	2.9	0.0
10	Small Thermal & Misc.	0.0	0.0	0.0
11	**Contract Purchases**	**237.7**	**262.8**	**-25.2**
12	Imports	40.0	57.5	-17.5
13	Intra-Regional Transfers (In)	25.8	33.5	-7.7
14	Non-Federal CER	137.2	136.1	1.1
15	Slice Transmission Loss Return	34.7	35.8	-1.1
16	**Reserves & Losses**	**-246.8**	**-235.0**	**-11.7**
17	Contingency Reserves (Spinning)	0.0	0.0	0.0
18	Contingency Reserves (Non-Spinning)	0.0	0.0	0.0
19	Load Following Reserves	0.0	0.0	0.0
20	Generation Imbalance Reserves	0.0	0.0	0.0
21	Transmission Losses	-246.8	-235.0	-11.7
22	**Total Net Resources** **(Line 1+4+11+16)**	**7,719.3**	**7,929.8**	**-210.5**

Appendix

BP-16 Preliminary Federal Resource Forecast

BP-16 Preliminary versus BP-14 Final Proposal Components for the Averaged 80 Water Conditions

	2-Year Average Comparison BP-16 Final BP-14 Final *(Energy in aMW)*	BP-16 Prelim Study	BP-14 Final Proposal	Difference 2-Year Average
1	**Net Hydro**	**8,909.0**	**8,922.0**	**-13.0**
2	Regulated Hydro - Net	8,482.0	8,495.0	-13.0
3	Independent Hydro - Net	427.0	427.0	0.0
4	**Other Resources**	**1,064.0**	**1,036.2**	**27.9**
5	Cogeneration Resources	5.4	19.2	-13.8
6	Combustion Turbines	0.0	0.0	0.0
7	Large Thermal Resources	995.6	953.8	41.8
8	Renewable Resources	60.1	60.3	-0.2
9	Small Hydro Resources	2.9	2.9	0.0
10	Small Thermal & Misc.	0.0	0.0	0.0
11	**Contract Purchases**	**237.7**	**262.8**	**-25.2**
12	Imports	40.0	57.5	-17.5
13	Intra-Regional Transfers (In)	25.8	33.5	-7.7
14	Non-Federal CER	137.2	136.1	1.1
15	Slice Transmission Loss Return	34.7	35.8	-1.1
16	**Reserves & Losses**	**-313.4**	**-293.0**	**-20.4**
17	Contingency Reserves (Spinning)	0.0	0.0	0.0
18	Contingency Reserves (Non-Spinning)	0.0	0.0	0.0
19	Load Following Reserves	0.0	0.0	0.0
20	Generation Imbalance Reserves	0.0	0.0	0.0
21	Transmission Losses	-313.4	-293.0	-20.4
22	**Total Net Resources** **(Line 1+4+11+16)**	**9,897.3**	**9,928.0**	**-30.7**

Appendix

BP-16 Preliminary – BPA/PASA/RVSD Contracts Exports

BPA/PASA Expires 4/30/2015
BPA/RVSD Expires 4/30/2016

	Energy-aMW	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul	Aug1	Aug16	Sep	Avg
	FY 2014 BPA/PASA/RVSD Exports															
1	BPA-P to PASA CNX Del	0	0	0	0	0	0	0	0	0	0	4.6	4.4	4.1	4.6	1.1
2	BPA-P to PASA SNX Del	0	0	0	0	0	0	0	0	15.0	15.0	0	0	0	0	2.5
3	BPA-P to RVSD CNX Del	11.1	2.6	2.7	2.8	2.7	2.5	2.8	2.8	0.0	0.0	11.1	10.5	9.8	11.0	5.0
4	BPA-P to RVSD SNX Del	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	40.0	40.0	0.0	0.0	0.0	0.0	6.7
5	Total BPA/PASA/RVSD Exports	11.1	2.6	2.7	2.8	2.7	2.5	2.8	2.8	55.0	55.0	15.8	14.9	13.9	15.6	15.3
	FY 2015 BPA/PASA/RVSD Exports															
6	BPA-P to PASA CNX Del	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	BPA-P to PASA SNX Del	0	0	0	0	0	0	0	0	15.0	15.0	0	0	0	0	2.5
8	BPA-P to RVSD CNX Del	11.1	2.5	2.8	2.7	2.7	2.7	2.8	2.8	0.0	0.0	11.1	10.5	9.8	11.0	5.0
9	BPA-P to RVSD SNX Del	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	40.0	40.0	0.0	0.0	0.0	0.0	6.7
10	Total BPA/PASA/RVSD Exports	11.1	2.5	2.8	2.7	2.7	2.7	2.8	2.8	55.0	55.0	11.1	10.5	9.8	11.0	14.2
	FY 2016 BPA/PASA/RVSD Exports															
11	BPA-P to PASA CNX Del	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	BPA-P to PASA SNX Del	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	BPA-P to RVSD CNX Del	10.6	2.6	2.8	2.5	2.7	2.8	2.6	2.6	0	0	0	0	0	0	2.2
14	BPA-P to RVSD SNX Del	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Total BPA/PASA/RVSD Exports	10.6	2.6	2.8	2.5	2.7	2.8	2.6	2.6	0	0	0	0	0	0	2.2
	FY 2017 BPA/PASA/RVSD Exports															
16	BPA-P to PASA CNX Del	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	BPA-P to PASA SNX Del	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	BPA-P to RVSD CNX Del	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19	BPA-P to RVSD SNX Del	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Total BPA/RVSD Exports	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Appendix
BP-16 Preliminary – BPA/PASA/RVSD Contracts Imports

BPA/PASA Expires 4/30/2015
BPA/RVSD Expires 4/30/2016

	Energy-aMW	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul	Aug1	Aug16	Sep	Avg
	FY 2014 BPA/PASA/RVSD Imports															
1	PASA to BPA-P CNX EER	3.4	3.5	3.6	3.4	3.5	1.7	0	0	0	0	0	0	0	3.5	1.9
2	PASA to BPA-P CNX Repl	0.2	0	0	0	0	0	0	0	0	0	4.4	4.3	4.5	4.4	1.1
3	PASA to BPA-P SNX Ret	4.6	4.6	4.8	4.6	4.7	2.2	0	0	0	0	0	0	0	4.6	2.5
4	RVSD to BPA-P CNX EER	0	16.3	16.2	15.6	16.1	16.8	7.9	7.9	0	0	0	0	0	0	7.3
5	RVSD to BPA-P CNX Repl	11.1	3.1	2.5	2.8	2.7	2.5	2.8	2.8	0.1	0	10.6	10.5	10.8	10.5	5.0
6	RVSD to BPA-P SNX Ret	0	9.4	9.3	9.0	9.3	9.7	4.5	4.5	0	0	0	0	0	0	4.2
7	Total BPA/PASA/RVSD Imports	19.4	36.9	36.4	35.4	36.2	32.9	15.2	15.2	0.1	0	15.1	14.8	15.4	23.0	22.1
	FY 2015 BPA/PASA/RVSD Imports															
8	PASA to BPA-P CNX EER	3.4	3.6	3.4	3.4	3.5	1.8	0	0	0	0	0	0	0	0	1.6
9	PASA to BPA-P CNX Repl	0.2	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
10	PASA to BPA-P SNX Ret	4.6	4.8	4.6	4.6	4.7	2.4	0	0	0	0	0	0	0	0	2.1
11	RVSD to BPA-P CNX EER	0	16.9	15.6	16.2	16.1	16.2	7.9	7.9	0	0	0	0	0	0	7.3
12	RVSD to BPA-P CNX Repl	11.1	3.0	2.7	2.8	2.7	2.5	2.8	2.8	0.1	0	10.6	10.0	10.3	11.0	5.0
13	RVSD to BPA-P SNX Ret	0	9.8	9.0	9.3	9.3	9.4	4.5	4.5	0	0	0	0	0	0	4.2
14	Total BPA/PASA/RVSD Imports	19.4	38.1	35.3	36.3	36.2	32.3	15.2	15.2	0.1	0	10.6	10.0	10.3	11.0	20.3
	FY 2016 BPA/PASA/RVSD Imports															
15	PASA to BPA-P CNX EER	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16	PASA to BPA-P CNX Repl	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	PASA to BPA-P SNX Ret	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	RVSD to BPA-P CNX EER	0	16.4	15.6	16.8	16.0	15.6	7.9	7.9	0	0	0	0	0	0	7.3
19	RVSD to BPA-P CNX Repl	11.1	2.5	2.8	2.7	2.6	2.8	2.8	2.8	0	0	0	0	0	0	2.3
20	RVSD to BPA-P SNX Ret	0	15.4	14.2	15.7	14.5	13.7	6.9	6.9	0	0	0	0	0	0	6.7
21	Total BPA/PASA/RVSD Imports	11.1	34.2	32.6	35.2	33.0	32.1	17.5	17.5	0	0	0	0	0	0	16.3
	FY 2017 BPA/PASA/RVSD Imports															
22	PASA to BPA-P CNX EER	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
23	PASA to BPA-P CNX Repl	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24	PASA to BPA-P SNX Ret	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
25	RVSD to BPA-P CNX EER	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
26	RVSD to BPA-P CNX Repl	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
27	RVSD to BPA-P SNX Ret	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28	Total BPA/PASA/RVSD Exports	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Rate Impact of a Tier 1 System Change

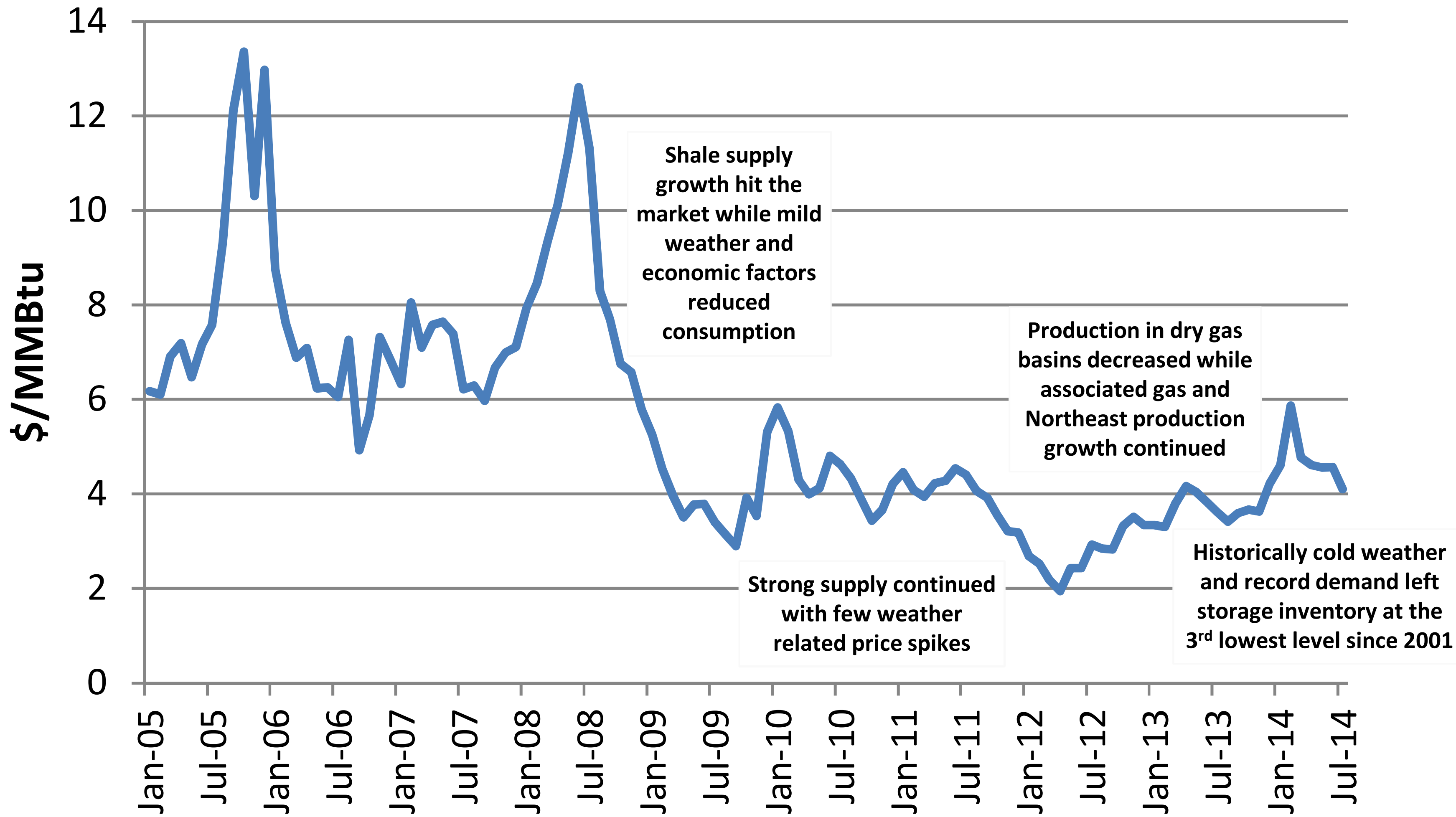
- BPA estimates 172 aMW less generation under critical, and roughly 14 aMW less secondary hydro generation under average water
- The exact impact on the PF Tier 1 Rate is not yet modeled, but generally:
  - Less generation under 1937 water lowers individual customers' Rate Period High Water Marks, which lowers Tier 1 Sales. Since the PF Tier 1 Rate equals Revenue Requirement divided by Sales, this pushes the rate higher.
- Sales impact is mitigated by
  - Increased secondary revenues – Because Tier 1 Sales are tied to 1937 critical generation (on an annual average basis), the widening of the difference between average water generation and 1937 critical water generation increases anticipated secondary energy sold on the trading floor.
  - Existence of Headroom (some customers having a net requirement that is smaller than its Rate Period High Water Mark). A portion of the 172 aMW decrease in 1937 critical generation will not lead to lower Tier 1 Sales.
    - However, since Headroom decreases system augmentation requirements to serve DSI loads, additional augmentation expenses will increase the revenue requirement.
- The bottom-line rate effect is not known yet.

RHWM Process Follow-up

- Responses to RHWM Process information requests are posted at:
  - http://www.bpa.gov/power/pl/regionaldialogue/implementation/documents/#HW
- To request a briefing on RHWM Process resource assumptions/modelling, contact BPA via the Tech Forum.
  - Send email to “techforum@bpa.gov” and include “RHWM Process” in the subject line.

Market Price

Henry Hub Price History



Natural Gas Market Continues to Evolve

Supply

- US production is expected to continue growing by more than 7 Bcf/d by 2018
- Supply growth will be dominated by lower cost resources including Marcellus and Utica, wet shale, and associated gas
- Take-away capacity and gas processing additions continue to come online
- Technology is aiding improved well results with greater use of multi-pad development, extended lateral lengths, lateral spacing, and improved targeting of sweet spots
- Technically recoverable resource estimates continue to grow

Demand

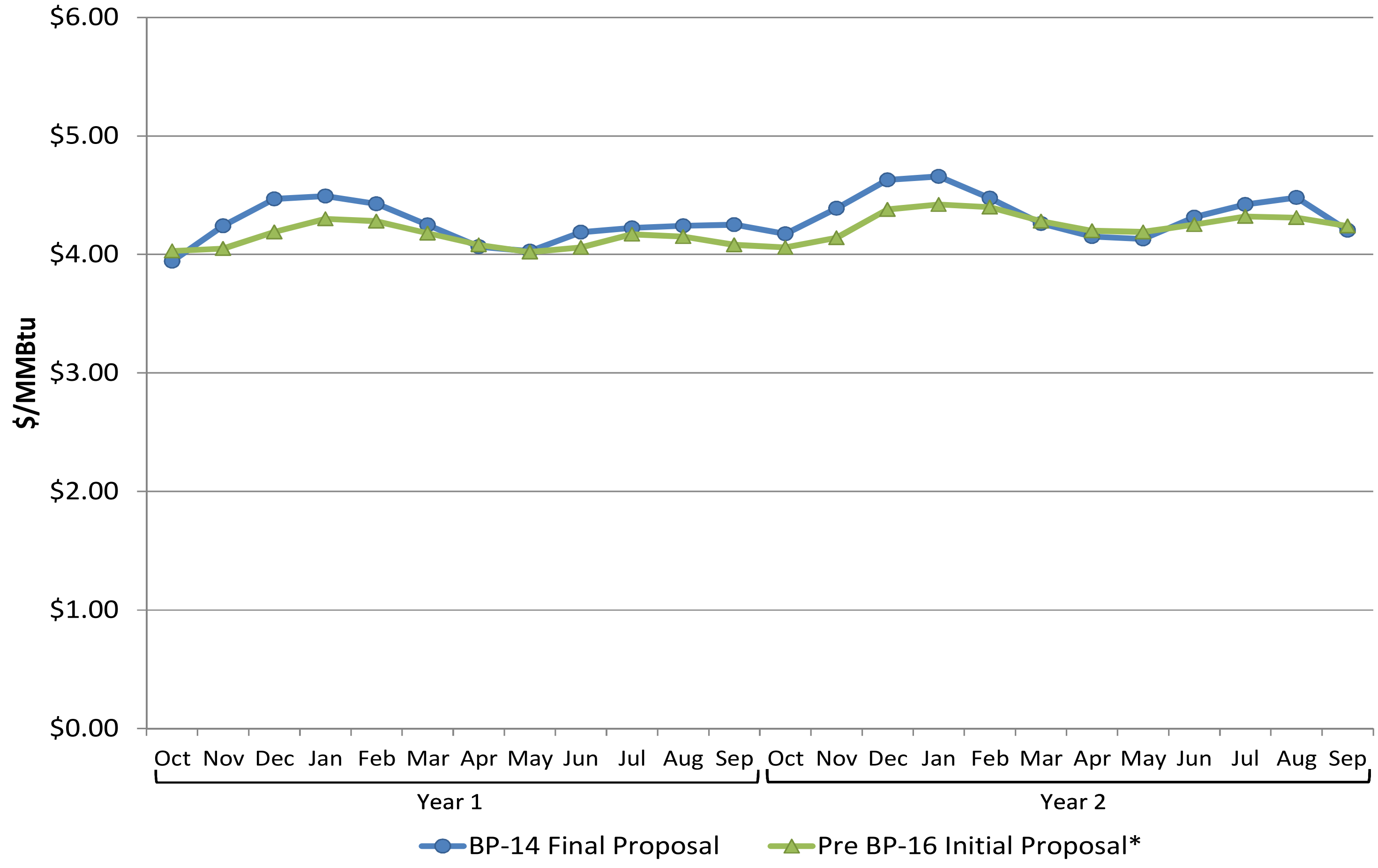
- LNG exports will begin in 2016 while not exceeding 2 Bcf/d until 2018
- Electric generation is expected to increase between 2 and 4 Bcf/d by 2017
- Industrial demand is expected to increase by as much as 2 Bcf/d by 2017
- Exports to Mexico are expected to increase by as much as 1 Bcf/d by 2017

Uncertainties

- Weather related demand
- Additional regulation and policy impacting production (water, air/flaring, land) or pipeline infrastructure (methane emissions, pipe replacement, permitting)
- Larger than expected impact of emission rules on natural gas-fired generation
- Oil price impact on associated gas production and drilling rig demand
- Volatility of LNG demand

With the exception of strong seasonal demand, low cost production is expected to keep pace with demand growth through the BP-16 time period. In the long term, prices are expected to gradually increase as higher cost resources return to the market to meet demand growth.

Henry Hub Price Outlook

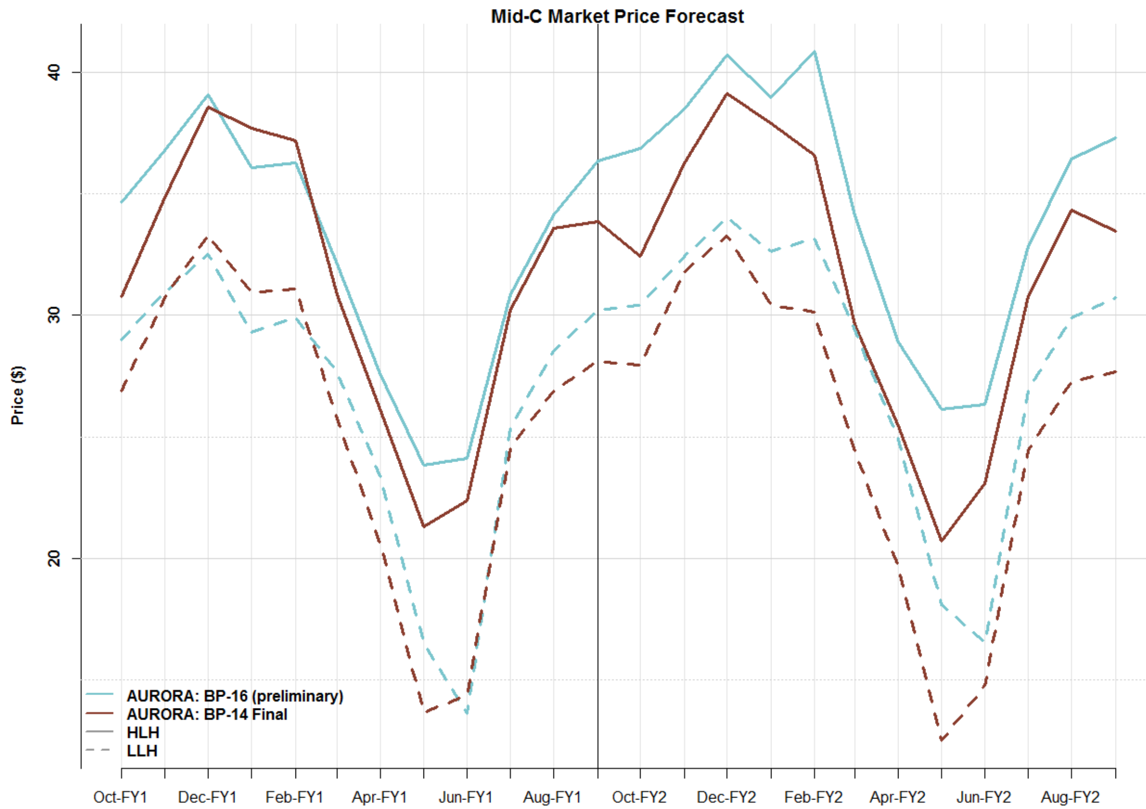


* Henry Hub forecast subject to revision for Initial Proposal

Electricity Market Prices

- Will use AURORA to value secondary market energy
- Model changes
  - New long term resource build
  - New natural gas forecast
  - Modeling negative Mid-C prices
    - Revenue floor at $0
  - New wind risk model
  - New transmission risk model
  - Decoupled California and BC hydro risk from PNW water years
  - Changes to hydro shaping constraints
  - Standard version/database upgrades
- Not modeled
  - California carbon

Comparison to BP14 prices (nominal)



- Bulk of net secondary revenue during Q2
- California solar shaving summer peaks
  - January "dip" result of higher hydro generation
- No *generic* resource additions in PNW during rate period
  - Port Westward/Carty/Tucannon incl.