Generation Inputs Workshop

1 April 2014

Agenda for 1 April 2014

- Balancing Reserve Forecast Performance Update: R3T Backcasting
- Options to Intra-Hour Transmission Product
- Embedded Cost Allocation Scenarios
- Beta Test and Preliminary Pilot Proposal for Pre-schedule Imbalance Capacity Acquisitions
- Consideration of a Separate Public Process for Imbalance Service Rate Case Inputs
- Customer Presentations

Balancing Reserve Forecast Performance Update

Frank Puyleart

Balancing Reserve Forecast Performance Update

- Balancing Reserve Forecast (BRF):
  - Real-Time Reserve Requirement Tool (R3T) is the internal option or “build” option
  - One vendor (WEPROG) is producing an external option or “buy” option.
  - Both Balancing Reserve Forecasts are produced every hour for 168 hours into the future.
- The purpose of this presentation is to present analytics on the R3T forecast performance
- This presentation is NOT meant to address:
  - Presence and Depth of Market
  - Resource Sufficiency
  - Viability of business case

R3T Update

- R3T was originally intended to forecast only INC reserves.
- R3T INC forecasts are the actual output from the R3T prototype (stored in PI).
- An estimate of DEC reserves was constructed which mimics the algorithm for INC reserves:
  - When time allows, we will have it incorporated into the running prototype and stored in PI.

R3T Update Assumptions

- Actual R3T performance analyzed for BP-14:
  - Time frame is 10/16/13 to 3/11/14.
  - R3T forecast was active and valid for the entire WECC preschedule timeframe since mid-October 2013.
  - Actual R3T performance uses the BPA Super Forecast, which meshes several vendor forecasts into a superior forecast.
- Backcast R3T performance analyzed for BP-12:
  - Time frame is 10/1/11 to 10/1/13.
  - Backcast R3T performance uses a combination of the BPA Super Forecast (out 3 days) and the 7 day forecast from one vendor (less accurate than SF).

R3T Update Assumptions

- Assumptions:
  - R3T forecast snapshot from 7:00 AM on day of preschedule timeframe used in analysis
  - Typical forecast timeframe used is for 36-60 hours into the future:
    - Forecast for 18-42 hours out on the low end
    - Forecast for 114-138 hours out on the high end:
      - Due to weekends and WECC holidays

R3T Performance Update

- Assumptions:
  - Forecast performance analyzed in two manners:
    - Using R3T Hourly Forecast as the reserves held
    - Using the maximum of the R3T 24-hour Hourly Forecasts for that day as the reserves held
  - Forecast performance measure against what BPA actually held for reserves for that period of time.
  - Performance measures:
    - Possible DSO 216 Events (Limits/Curtailments Separate)

BP-14 Actual R3T Performance Update

DSO 216 Performance for BP-14

Scenario	Limitations	Curtailments
Actual Reserves Held *(Average held = 955 MW)*	3	2
R3T Hourly Forecast	31	20
R3T 24-Hr Max Forecast	15	13

- These are for level 1 DSO 216 events (90% reserves deployed)
- **NOTE:** 99.5% coverage under the current BP-14 balancing reserves methodology does not have a direct translation into the coverage that could be given under the R3T forecast.

BP-12 Backcast R3T Performance Update

DSO 216 Performance for BP-12

Scenario	Limitations	Curtailments
Actual Reserves Held *(Average held = 705 MW)*	141	128
R3T Hourly Forecast	101	70
R3T 24-Hr Max Forecast	68	35

- These are for level 1 DSO 216 events (90% reserves deployed)
- **NOTE**: 99.5% coverage under the current BP-12 balancing reserves methodology does not have a direct translation into the coverage that could be given under the R3T forecast.

R3T Performance Update

- Assumptions:
  - Hypothetical reserve “buying” analyzed in two ways:
    - Use R3T forecast at face value:
      - Assumes “buying” equal to 100% of the R3T forecast
        - Not feasible given current systems and markets
      - For both 24-hour max or hourly scenarios
    - Use R3T forecast to supplement actual reserves held
      - Assumes “buying” equal to R3T forecast amounts above actual reserves held (941 MW currently)
      - For both 24-hour max or hourly scenarios
  - “Buying” measures:
    - MW “bought” versus reserves held:
      - Average and Maximum for INC only
    - Number of “purchase” periods

BP-14 Actual R3T Performance Update

“Buying” Measures(INC Only, Period Avg., 10/16/13 to 3/11/14)

	“Buying” Scenarios	Avg. Cap. “Bought”	Max Cap “Bought”	# of Periods
1	Actual Reserves Held	955 MW	970 MW	4368 hr 182 days
2	Reserves “bought” using R3T 24-Hr Max Forecast at Face Value*	759 MW	1226 MW	4368 hrs 182 days
3	Reserves “bought” using R3T Hourly Forecast at Face Value*	661 MW	1226 MW	4368 hrs 182 days
4	Reserves “bought” using R3T 24-Hr Max Forecast to Supplement Reserves Held	101 MW	258 MW	624 hrs 26 days
5	Reserves “bought” using R3T Hourly Forecast to Supplement Reserves Held	94 MW	258 MW	166 hrs

* This is not feasible given current systems and markets

BP-12 Backcast R3T Performance Update

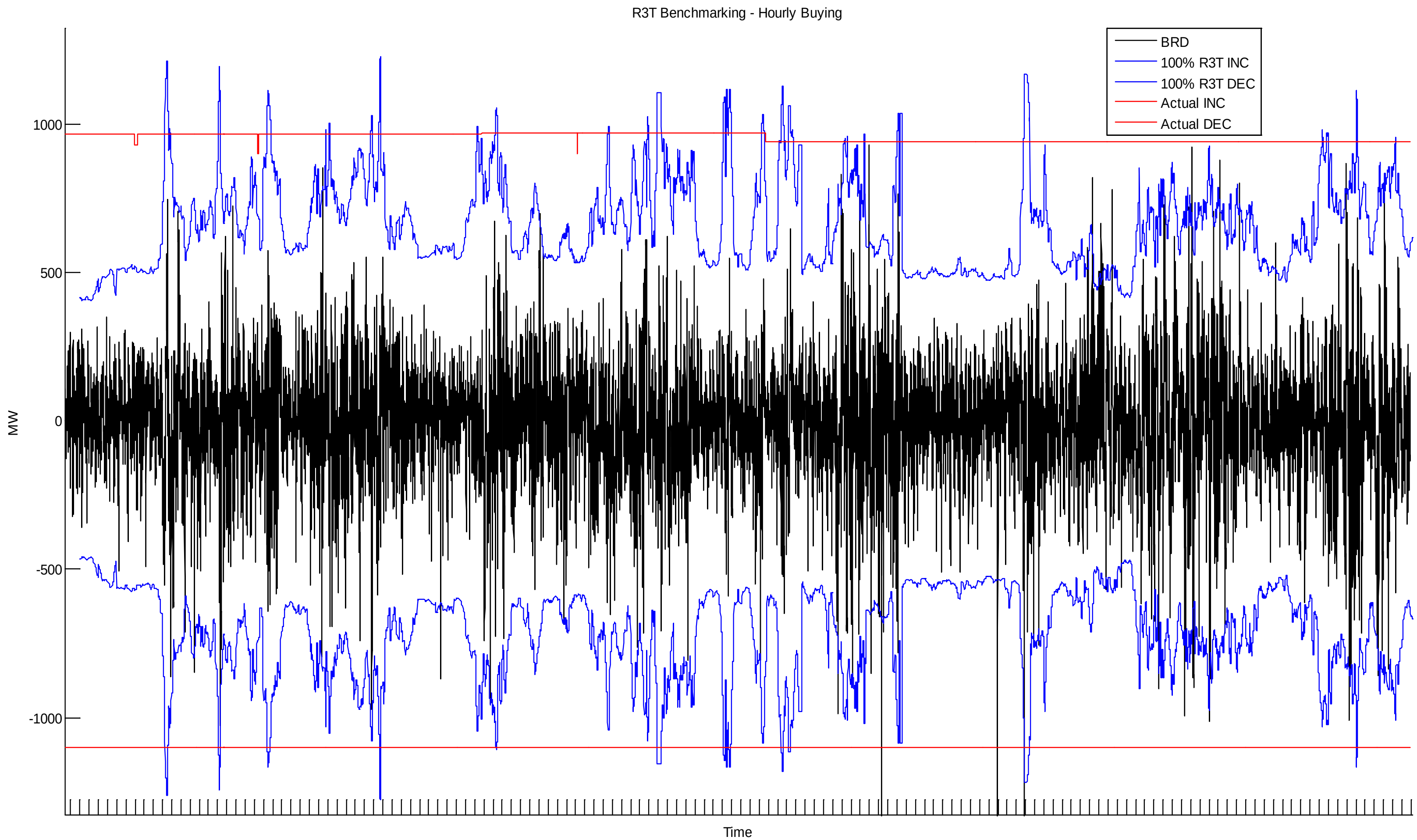
"Buying" Measures(INC Only, Period Avg., 10/1/11 to 10/1/13)

	"Buying" Scenarios	Avg. Cap. "Bought"	Max Cap "Bought"	# of Periods
1	Actual Reserves Held	705 MW	774 MW	17537 hr 731 days
2	Reserves "bought" using R3T 24-Hr Max Forecast at Face Value*	795 MW	1188 MW	17537 hr 731 days
3	Reserves "bought" using R3T Hourly Forecast at Face Value*	682 MW	1188 MW	17537 hr 731 days
4	Reserves "bought" using R3T 24-Hr Max Forecast to Supplement Reserves Held	162 MW	729 MW	12502 hrs 521 days
5	Reserves "bought" using R3T Hourly Forecast to Supplement Reserves Held	145 MW	729 MW	6058 hrs

* This is not feasible given current systems and markets

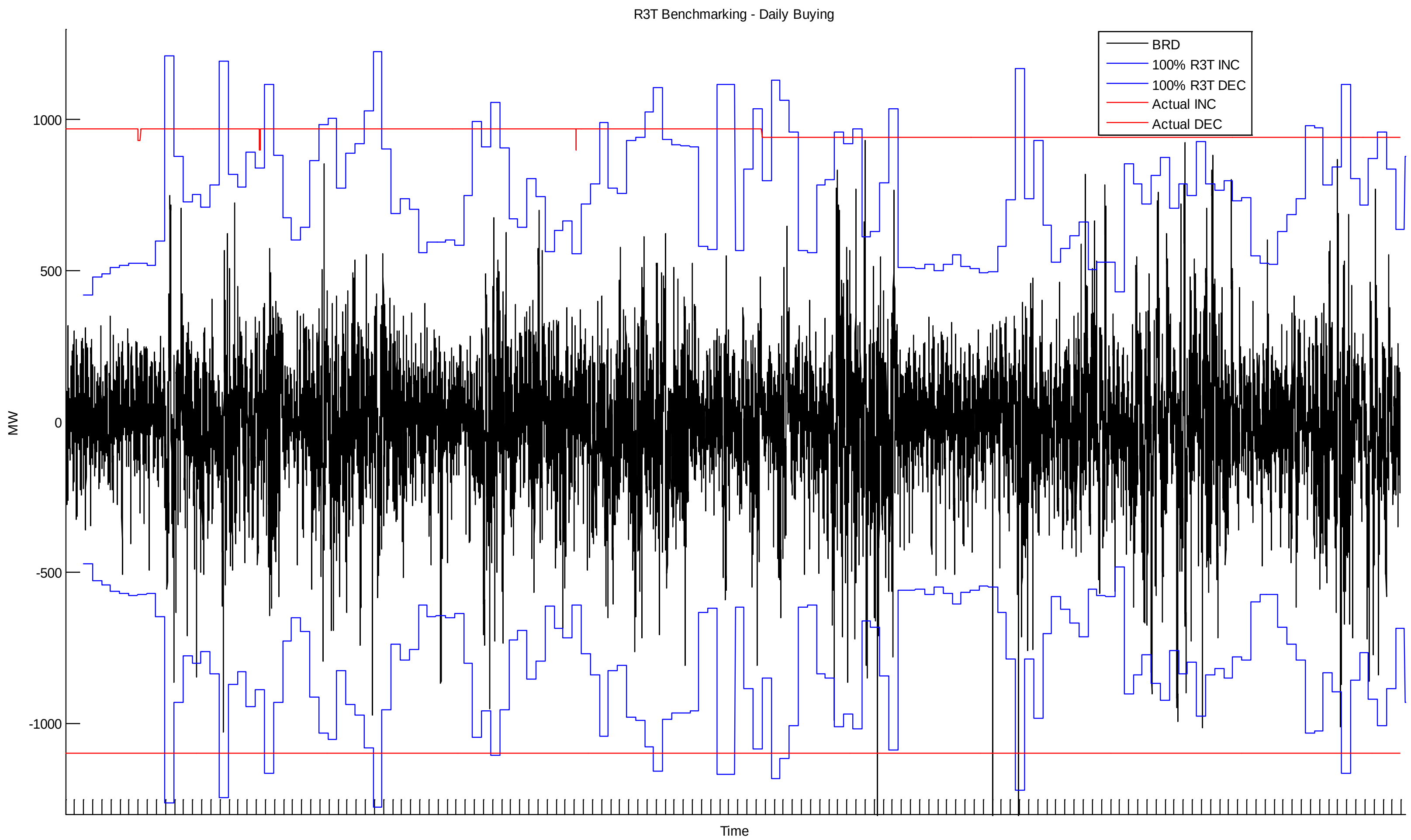
BP-14 Actual R3T Update - Hourly

10/16/2013-3/11/2014



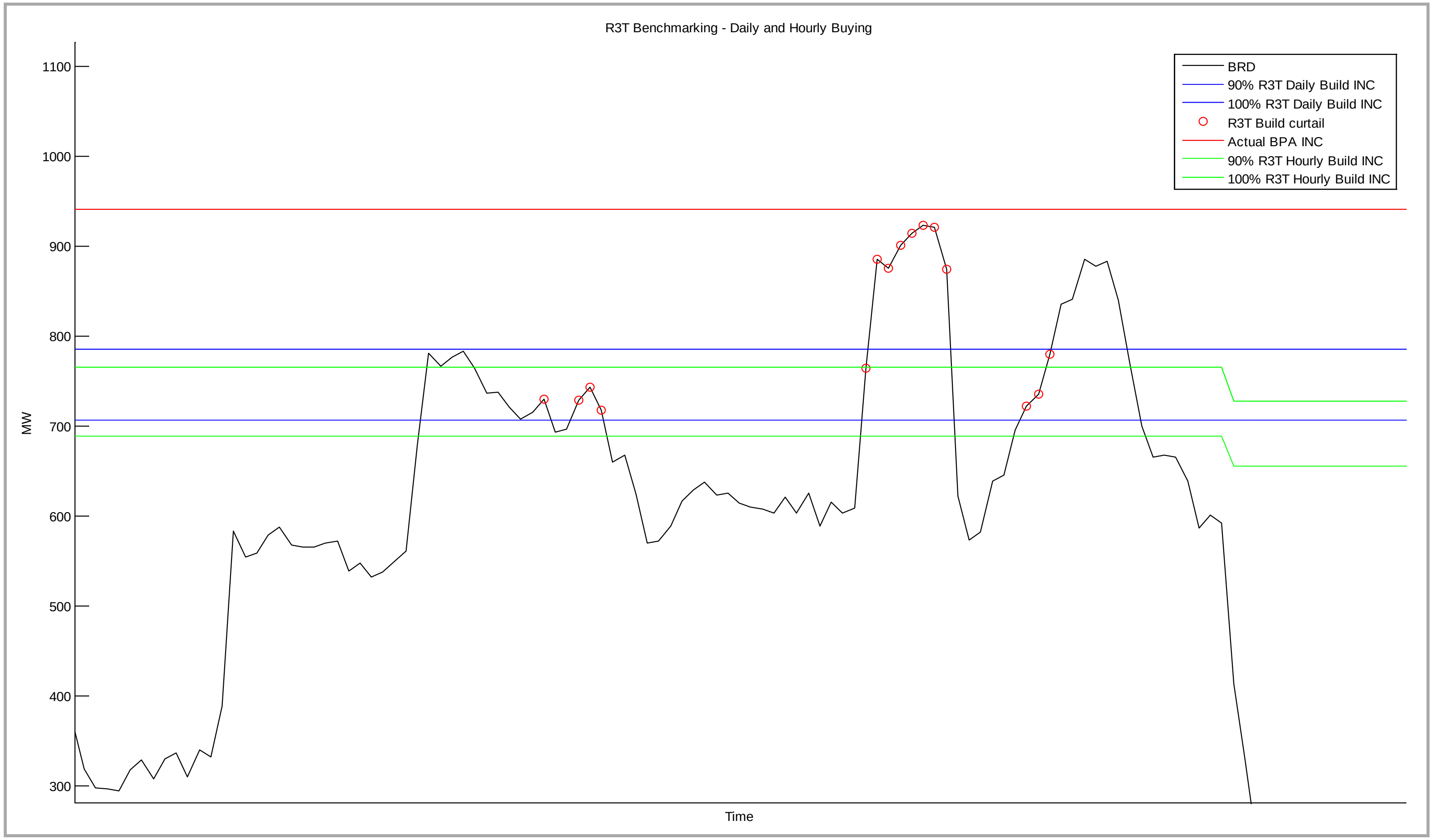
BP-14 Actual R3T Update - 24-hr Max

10/16/2013-3/11/2014



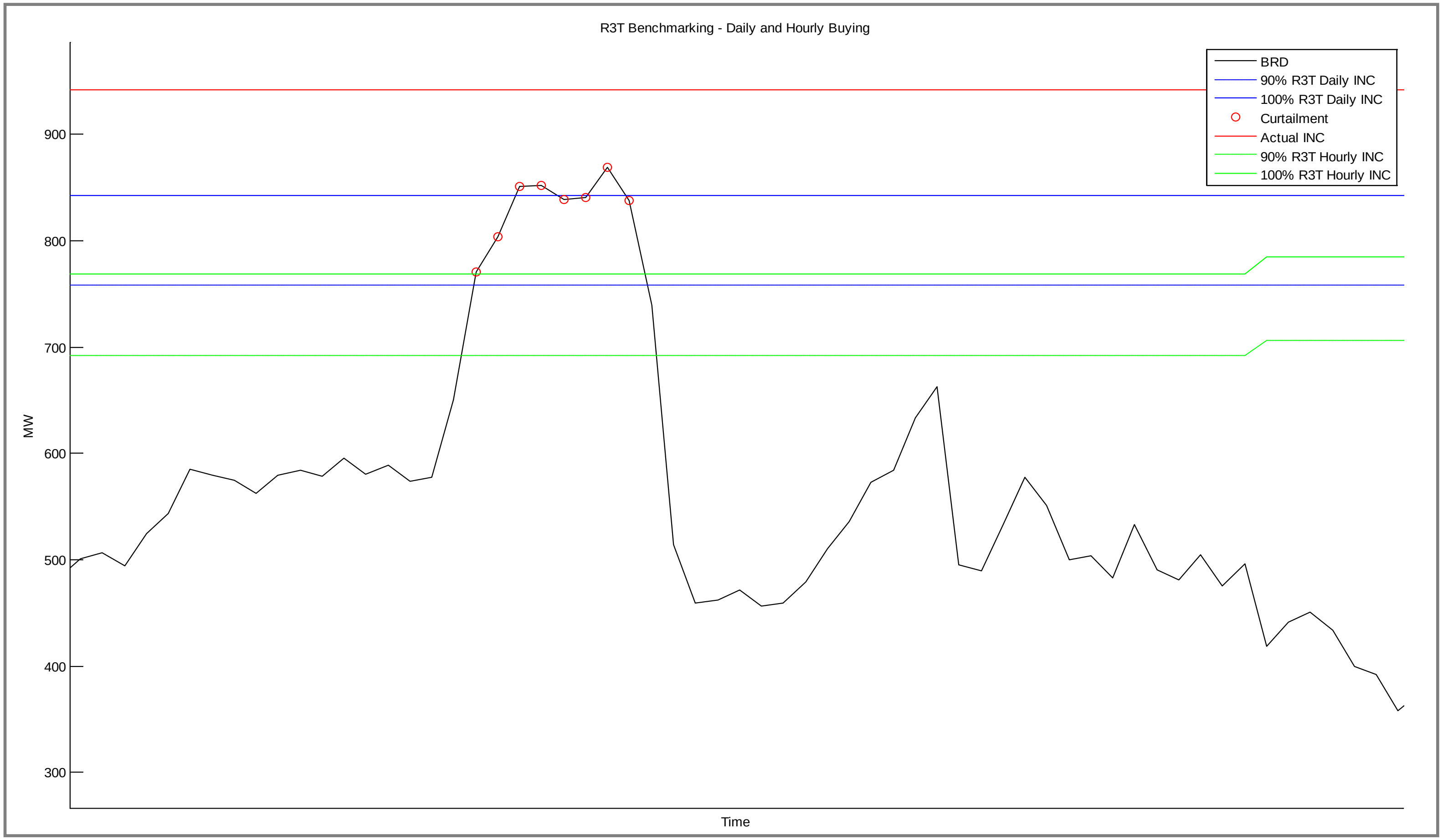
DSO 216 Close-Up

- 2/16/2014 Actual DSO 216 Curtailment
- R3T hourly, daily and actual reserves held failed.



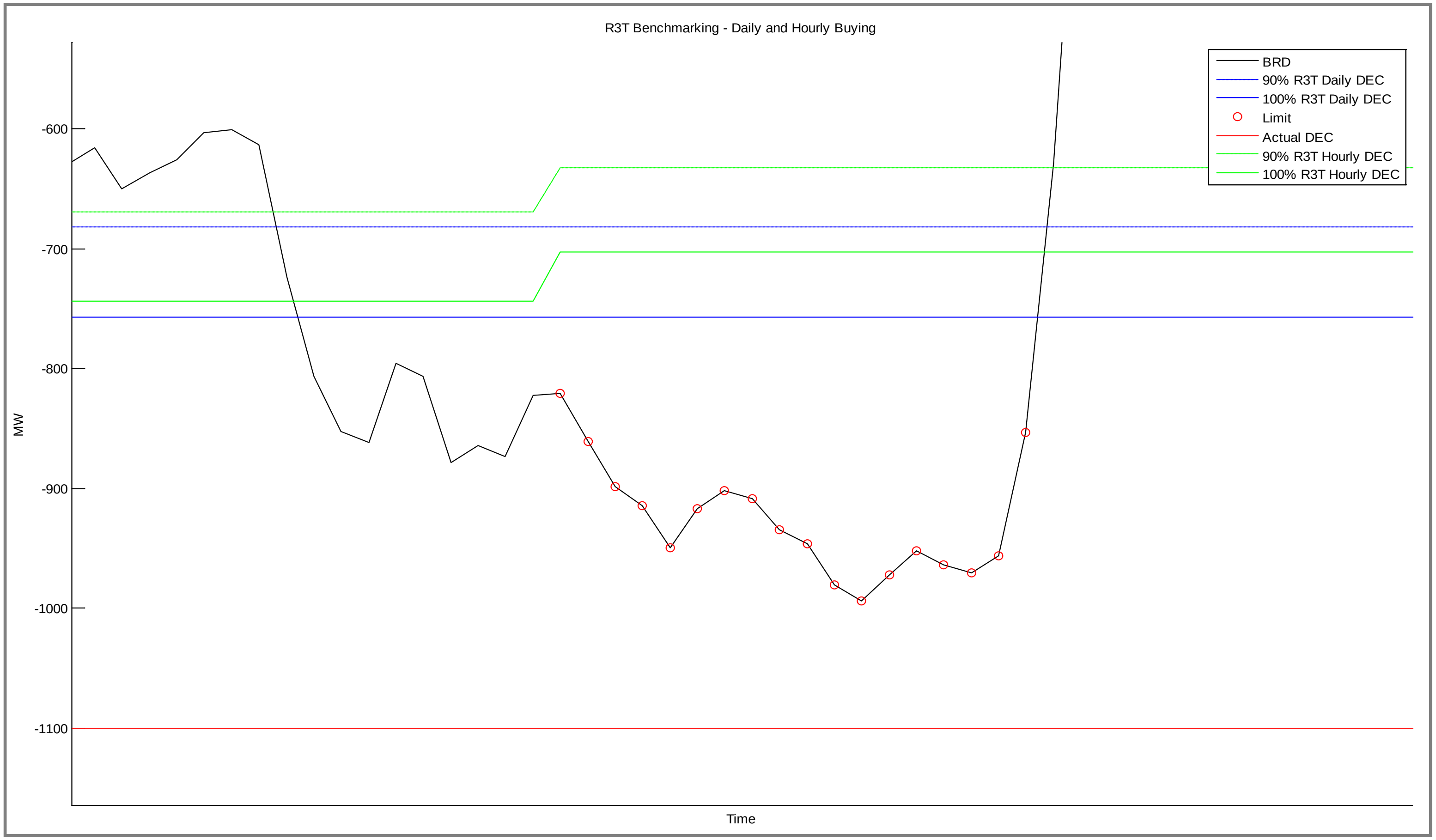
DSO 216 Close-Up

- 3/5/2014 Actual DSO 216 Curtailment
- R3T hourly, daily and actual reserves held failed.



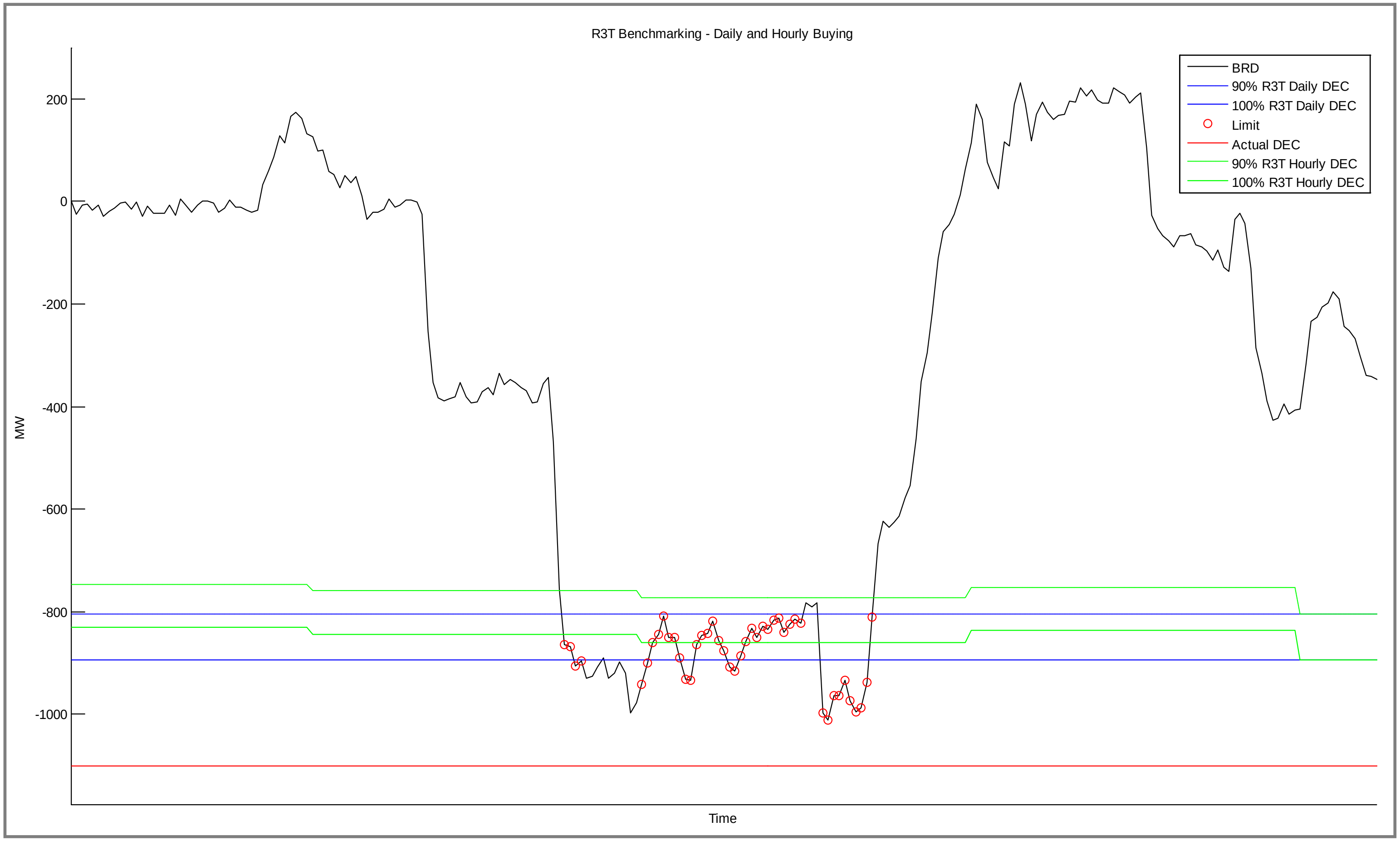
DSO 216 Close-Up

- 2/15/2014 Actual DSO 216 Limitation
- R3T hourly, daily and actual reserves held failed.



DSO 216 Close-Up

- 3/5/2014 Actual DSO 216 Limitation
- R3T hourly, daily and actual reserves held failed.



Options to
Intra-Hour Transmission Product

Brad Hansen and Eric King

Options to Intra-Hour

- Parties currently have the ability to redirect a portion of their existing transmission rights. This would include the ability to redirect as needed to support 15-minute schedules.

- BPA staff believes that the ability to redirect a portion of existing transmission rights should address the majority of needs.

- In order 764, FERC required transmission providers to allow parties the ability to use 15-minute scheduling. However, FERC specifically did not require transmission provider to offer a 15-minute transmission product.

Options to Intra-Hour (continued)

- Given the cost that would be incurred, and given the ability to redirect existing transmission rights, it is not clear that there would be sufficient demand for a 15-minute transmission product to justify the expense and effort. BPA Staff would recommend that the region wait until after 15-minute scheduling is fully offered before looking at the need for a 15-minute transmission product.

- Relinquish requests are limited to whole hours like Redirects. While BPA has validation that should disallow the Relinquish of 1-NS rights that are scheduled for any part of an hour, the responsibility to stay within their rights is the customer's.

Embedded Cost Allocation Scenarios

Janet Ross Klippstein

Embedded Cost Allocation

- Objective is to provide information about BP-14 Initial Proposal embedded cost allocation method and inputs

- As part of the Generation Inputs Partial Settlement of the BP-14 Rate Case, in Attachment 1, section 10. g., “In order to help inform customers’ proposals, Bonneville will conduct an educational workshop with information pertaining to the cost basis and rate design of Bonneville’s balancing services. This educational workshop will include information and discussion of:

  i. The 120-hour and 1-hour peaking capability and associated energy content;

  ii. The cost basis of balancing services (including net revenues from secondary sales); and

  iii. The use and availability of balancing reserve capacity for Load, Dispatchable Energy Resources, and Variable Energy Resources.”

Outline of Presentation

- Review embedded cost allocation methodology used in the BP-14 Generation Inputs Initial Proposal.
- Peaking capability and associated energy forecasts for FY 2014 and FY 2015 rate period under different scenarios from the BP-14 Final Study.
- Application of the current embedded cost allocation methodology to 12 scenarios with the key variable assumptions of 120-hour and 1-hour peaking capability, average water and critical water, and a proportion of the net secondary revenue credit.
  - Scenario inputs are based, to the extent possible, on a consistent source of public information (BP-14 Initial Proposal).
  - Scenarios are included to illustrate the concepts for the different cost allocation assumptions. They do not represent the numbers that would be in the BP-16 Initial Proposal.
- Provide information for discussion and development of customer proposals.

BP-14 Initial Proposal Embedded Cost Allocation Methodology

- The methodology divided the embedded cost net revenue requirement associated with the Big 10 hydro projects by the 120-hour peaking capacity total system uses to determine a unit cost for capacity uses. The unit cost was multiplied by regulating, VERBS and DERBS balancing reserve quantities to calculate the embedded cost allocation for each service.
- The net revenue requirement is comprised of the Big 10 hydro projects and a proportion of the Fish and Wildlife and Administration and General expenses minus three revenue credits. For the FY 2014-FY 2015 rate period, annual average was $927,156,000:
  - Project-specific costs of the Big 10 hydro projects (operations and maintenance, depreciation, net interest, minimum required net revenues, and planned net revenues for risk)
  - Proportionate share of Fish and Wildlife (operations and maintenance, depreciation, net interest, minimum required net revenues, and planned net revenues for risk)

BP-14 Initial Proposal Embedded Cost Allocation Methodology (continued)

- Net revenue requirement (continued)
- Proportionate share of Administrative and General expense
- Revenue credits are a share of 4(h)10(C) (non-operations), Colville payment Treasury Credit, and Synchronous Condensing.

- The balancing reserve capacity quantities were:
    - Regulating 61 MW *inc*
    - VERBS 522 MW *inc*
    - DERBS 61 MW *inc*
    - Operating Reserves 534 MW *inc*
    - Following Capacity (includes imbalance) 251 MW *inc*
    - Big 10 hydro projects 9724 MW

BP-14 Initial Proposal
Balancing Reserve Capacity Reserve
Power Net Revenue Requirement for Big 10 Projects in BPA Balancing Authority Area
($ in thousands)

	A	B	C	D
	Summary of Table 3.5 from Generation Inputs Study Documentation, BP-14-E-BPA-05A-E01	**FY 2014**	**FY 2015**	**Annual Average for FY 2014-FY 2015**
1	**Big 10 Hydro Projects Revenue Requirement**	$ 448,067	$ 462,592	**$ 455,330**
2	**Fish & Wildlife**	$ 428,820	$ 442,228	**$ 435,524**
3	**A&G Expense**	$ 104,303	$ 107,217	**$ 105,760**
4	**Total Revenue Requirement (Lines 1+2+3)**	$ 981,190	$ 1,012,037	**$ 996,614**
5	**Revenue Credits (4(h)10(C) non-operations, Colville Payment Treasury Credit, synchronous condensing)**	$ 70,766	$ 68,151	**$ 69,458**
6	**Net Revenue Requirement(Line 4-5)**	$ 910,424	$ 943,887	**$ 927,155**
	Footnotes			
	Line 1 is the sum of project-specific costs.			
	Lines 2 and 3 are an allocation of the total cost for that category based on the proportion of the Big 10 projects to Regulated Hydro. For the BP-14 Initial Proposal this was 94% as calculated in Table 3.2 of the documentation.			
	Line 5 is the sum of the revenue credits identified in the Initial Proposal that have been part of the calculation for several rate cases.			

BP-14 Initial Proposal
Embedded Cost Allocation Methodology

	Table 3.6 Summary from BP-14 Initial Proposal Cost Allocation for Embedded Cost Portion of Balancing Reserve Capacity Reserves at 99.5% Level of Service with Self Supply of Generation Imbalance for VERBS	
	A	**B**
	Average water conditions (1958 water)	**Annual Average of FY2014-FY2015**
	Assumptions for Calculation:	
1	Big 10 Hydro Projects Capacity adjusted for transmission losses	9,724
2	Regulating Reserve (MW)	61
3	Operating Reserve less Operating Reserve on rest of System (MW) 1/	534
4	Following Capacity Reserve (MW)	251
5	Variable Energy Resource Balancing Service Reserve (MW)	522
6	Dispatchable Energy Resource Balancing Service Reserve (MW)	61
7	**Forecast of Hydro Capacity System Uses:**	11,153
8	PS Net Revenue Requirement for Big 10 Hydro Projects	$ 927,156,000
9	Total kW/month/year Hydro Project Capacity System Uses (Line 7 * 12 months * 1000 kW/MW)	133,836,594
10	**Unit Cost Allocation of Capacity System Uses $/kW/month (Line 8 / Line 9)**	$ 6.93
11	**Revenue Forecast for Embedded Unit Cost by Balancing Reserve Capacity Service**	
12	Regulating Reserve (Line 2 * Line 10 * 12 months * 1000 kW/MW)	$ 5,072,760
13	VERBS Reserve (Line 5 * Line 10 * 12 months * 1000 kW/MW)	$ 43,409,520
14	DERBS Reserve (Line 6 * Line 10 * 12 months * 1000 kW/MW)	$ 5,072,760
	1/ The 558.9 MW for Operating Reserve is adjusted to account for 9% of the Non-Spinning portion (half of the total Operating Reserve) being supplied by the rest of the system. .	

Embedded Cost Scenarios

- The 14 scenarios varied these variables as requested:
  - 120-hour and 1-hour peaking capability
  - average water and critical water
  - Net secondary revenue credit.
- The scenarios are based on these groups of resources:
  - Big 10 hydro projects
  - Hydro projects in the BPA balancing authority
  - Total system resources (hydro, Federal thermal, power purchases)
- BP-14 Initial Proposal balancing reserve capacity quantities were kept constant across all scenarios.

Peaking Capability Values from the Load Obligation Resource Analyzer (LORA) Using BP-14 Final Study Data

Peaking Capability and Annual Average Energy for Big 10 Hydro, Regulated Hydro, Federal Columbia River Power System (Regulated and Independent Hydro), and Total Federal System (All Resources) on a Forecast Annual Average Basis for FY 2014-2015

	Resources	Water Condition	120-Hour Peaking Capability (MW) 1/, 2/	1-Hour Peaking Capability (MW) 1/, 2/	Annual Average Energy (aMW) 2/
	A	B	C	D	E
1	Big 10 Hydro	Critical (1937)	7,247	9,142	6,075
2	Big 10 Hydro	Average (1958)	9,186	10,695	8,067
3	Regulated Hydro	Critical (1937)	8,457	10,353	6,508
4	Regulated Hydro	Average (1958)	10,398	11,908	8,625
5	FCRPS (Regulated and Independent Hydro)	Critical (1937)	8,898	10,793	6,862
6	FCRPS (Regulated and Independent Hydro)	Average (1958)	10,928	12,437	9,052
7	Total Federal System (All Resources)	Critical (1937)	10,576	12,483	8,447
8	Total Federal System (All Resources)	Average (1958)	12,619	14,138	10,649

Footnotes

1/ Peaking Capability includes an adjustment for transmission losses at 3.35%. Peaking capability also includes an adjustment for operating reserves and balancing reserves capacity.

2/ All amounts are the annual average during the FY 2014 through FY 2015 rate period from the hydro studies used for the BP-14 Rate Case Final Study.

	BP-14 Initial Proposal Operating Reserve Power Net Revenue Requirement for All Hydro Projects in BPA Balancing Authority Area ($ in thousands)			
	Summary of Table 4.5 from Generation Inputs Study Documentation, BP-14-E-BPA-05A-E01	**FY 2014**	**FY 2015**	**Annual Average for FY 2014-FY 2015**
1	**All Hydro Projects in BPA Balancing Authority Revenue Requirement**	$ 558,948	$ 576,505	**$ 567,727**
2	**Fish & Wildlife**	$ 442,506	$ 456,342	**$ 449,424**
3	**A&G Expense**	$ 107,632	$ 110,639	**$ 109,135**
4	**Total Revenue Requirement (Lines 1+2+3)**	$1,109,086	$ 1,143,486	**$ 1,126,286**
5	**Revenue Credits (4(h)10(C) non-operations, Colville Payment Treasury Credit, synchronous condensing)**	$ 72,869	$ 70,172	**$ 71,521**
6	**Net Revenue Requirement (Line 4-5)**	$1,036,217	$ 1,073,314	**$ 1,054,766**
	Footnotes			
	Line 1 is the sum of project-specific costs.			
	Lines 2 and 3 are an allocation of the total cost for that category based on the proportion of the hydro projects in the BPA Balancing Authority Area to all hydro projects. For the BP-14 Initial Proposal this was 97%.			
	Line 5 is the sum of the revenue credits identified in the Initial Proposal that have been part of the calculation for several rate cases.			

	Scenario Balancing Reserve Capacity Power Net Revenue Requirement for Total Federal System (All Resources) ($ in thousands)			
	This table was built from information in the Power Revenue Requirement Study Documentation, BP-14-E-BPA-02A and Generation Inputs Study Documentation, BP-14-E-BPA-05A-E01.	**FY 2014**	**FY 2015**	**Annual Average for FY 2014-FY 2015**
1	**All Hydro Projects in BPA Balancing Authority Revenue Requirement**	$ 558,948	$ 576,505	**$ 567,727**
2	**Fish & Wildlife**	$ 442,506	$ 456,342	**$ 449,424**
3	**A&G Expense**	$ 107,632	$ 110,639	**$ 109,136**
4	**Columbia Generating Station**	$ 401,343	$ 433,361	**$ 417,352**
5	**Non-Federal Debt Service**	$ 415,093	$ 350,863	**$ 382,978**
6	**Renewables**	$ 35,299	$ 35,647	**$ 35,473**
7	**Long-Term Contract Generating Projects**	$ 25,999	$ 26,619	**$ 26,309**
8	**Hedging/Mitigation**	$ 35,043	$ -	**$ 17,522**
9	**Augmentation Purchases**	$ 27,611	$ 123,273	**$ 75,442**
10	**Power Purchases (Lines 6+7+8+9)**	$ 123,952	$ 185,539	**$ 154,746**
11	**Conservation**	$ 50,826	$ 49,632	**$ 50,229**
12	**Total Revenue Requirement (Lines 1+2+3+4+5+10+11)**	$ 2,100,300	$ 2,162,881	**$ 2,131,591**
13	**Revenue Credits (4(h)10(C) non-operations, Colville Payment Treasury Credit, synchronous condensing)**	$ 72,869	$ 70,172	**$ 71,521**
14	**Net Revenue Requirement (Line 12-13)**	$ 2,027,431	$ 2,092,709	**$ 2,060,070**
	Footnotes			
	Lines 1, 2 and 3 are the costs in hydro projects in the BPA Balancing Authority Area (BAA).			
	Line 4 is from Power Revenue Requirements Study Documentation, BP-14-E-BPA-02A, Table 3A, lines 3 and 93.			
	Line 5 is from Power Revenue Requirements Study Documentation, BP-14-E-BPA-02A, Table 3A, lines 94 and 95.			
	Line 6 is from Power Revenue Requirements Study Documentation, BP-14-E-BPA-02A, Table 3A, line 35 adjusted to include only the wind power purchases.			
	Line 7 is from Power Revenue Requirements Study Documentation, BP-14-E-BPA-02A, Table 3A, line 6.			
	Line 8 is from Power Revenue Requirements Study Documentation, BP-14-E-BPA-02A, Table 3A, line 19.			
	Line 9 is from Power Revenue Requirements Study Documentation, BP-14-E-BPA-02A, Table 3A, line 25.			
	Line 11 is from Power Revenue Requirements Study Documentation, BP-14-E-BPA-02A, Table 3A, lines 44 and 100.			

Net Secondary Revenue Credit Calculation for All Resources Scenarios

- Net Secondary Revenue Credit = Secondary Sales minus Balancing Purchases
- Secondary Sales amount is “BPA Secondary Sales Pre-Slice” taken from the Power Rate Study Documentation, BP-14-E-BPA-01A, Table 2.3.8, line 22.
- Balancing Purchases amount is “Other Power Purchases – (e.g. Short-Term)” taken from the Power Revenue Requirements Study Documentation, BP-14-E-BPA-02A, Table 3A, line 20:
  - This expense is from short-term balancing purchases.

Net Secondary Revenue Credit Based on BP-14 Initial Proposal ($ thousands)	**FY 2014**	**FY 2015**	**Annual Average for Rate Period**
Secondary Sales Pre-Slice revenue, Power Rate Study Documentation, BP-14-E-BPA-01A, Table 2.3.8, line 22.	$ 449,919	$ 466,114	**$ 458,017**
Balancing Purchases expense, Power Revenue Requirements Study Documentation, BP-14-E-BPA-02A, Table 3A, line 20.	$ 31,941	$ 27,492	**$ 29,717**
Net Secondary Revenue Credit	$ 417,978	$ 438,622	$ 428,300

Estimated Proportionate Net Secondary Revenue Credit from BP-14 Initial Proposal Under Critical Water Assumptions
($ in thousands)

		FY 2014	FY 2015	Annual Average for Rate Period	% of All Resources Costs based on Peaking Capability (Col E / Col F)	Peaking Capability (MW)	Peaking Capability of All Resources (MW)
		A	B	C	D	E	F
1	**All Resources (1-hour, critical water)**	$ 417,978	$ 438,622	**$ 428,300**	100%	12,483	12,483
2	**All Resources (120-hour, critical water)**	$ 417,978	$ 438,622	**$ 428,300**	100%	10,576	10,576
3	**FCRPS (1-hour, critical water)**	$ 361,390	$ 379,240	**$ 370,315**	86%	10,793	12,483
4	**FCRPS (120-hour, critical water)**	$ 351,661	$ 369,030	**$ 360,345**	84%	8,898	10,576
5	**Big 10 (1-hour, critical water)**	$ 306,109	$ 321,227	**$ 313,668**	73%	9,142	12,483
6	**Big 10 (120-hour, critical water)**	$ 286,411	$ 300,557	**$ 293,484**	69%	7,247	10,576
7	**Net Secondary Revenue Credit from BP-14 Initial Proposal**	$ 417,978	$ 438,622	$ 428,300			

Beta Test and Preliminary Pilot Proposal for Pre-schedule Imbalance Capacity Acquisitions

John Wellschlager

Objectives for today's discussion

- Provide an update on the Pre-schedule Operational Acquisitions (Type 2) implementation and beta testing for April.
- Provide an overview of a potential BPA staff response to a one month pilot for this Summer for short-term acquisitions requested by wind customers.

Background

- As part of the BP-14 Gen Inputs Rate Case Settlement, BPA committed to hold 900 MW FCRPS INCing capacity.
- BPA also acquired additional reserves, known as Planned Acquisitions (Type1), on a quarterly basis to meet Base Service levels of reliability (99.5%).
- BPA further agreed to attempt to acquire from a third-party supplier any capacity shortfall caused by operational constraints which prevent the FCRPS from supplying the agreed-upon 900 MW of INCs.
  - These reserves are defined as Operational Acquisitions (Type 2).
- Some of the reasons this could occur would be due to:
  - An oversupply situation.
  - Physical loss of FCRPS units (including Columbia Generating Station).
  - Any potential system loss or constraint which threatens BPA's ability to maintain the 900 MW of INCs.

Background (continued)

- During the BP-14 Gen Inputs Rate Case Settlement Workshops, RNP and other Wind advocates asked about targeting high-volatility wind events with short-term capacity acquisitions:
  - The Settlement allows BPA, after consultation with customers, to use part of the $2 million Acquisition Budget to strategically target high volatility wind events.

Types of Within-hour Reserve Acquisitions for FY 2014 - 2015

- **Planned Acquisitions* (Type 1)** – Monthly purchases required to cover the shortfall, if any, between the planned FCRPS balancing reserve capacity (900 MW INC, 1100 MW DEC) and the rate case planned balancing needs of base service (99.5% after adjusting for any self-supply of generation imbalance).
- **Operational Acquisitions* (Type 2) –** Purchases needed when BPA is either operationally unable or at risk of being unable to provide the planned FCRPS INC balancing reserve capacity necessary to meet the 99.5% reliability standard.
- **Full Service (Type 3) –** Purchases required to provide reserves for customer electing the VERB's Full Service balancing service plan. These will be made in smaller increments. Costs are charged to the full service customers.
- **Unplanned Service* (Type 4) –** Monthly purchases required to support an unplanned increase in balancing services required by the BPA BA. These costs are directly assigned to the customers that create the unanticipated increase.
- **VERBS Supplemental Service (Type 5) –** Optional monthly service where BPA purchases reserves on behalf of customers requesting an amount they define. This service would be in addition to the base service. Customers may also acquire their own Supplemental Service with less notice for shorter periods. Costs are charged to SS customers.

*these acquisitions are for meeting or maintaining our base level service with the 99.5% reliability standard.

Why are we proposing a beta test?

- Currently the process to begin Operational Acquisitions (Type 2) for pre-schedule Imbalance Capacity are targeted to be ready on April 1, 2014.
- These acquisitions are designed to be driven by short term needs that arise due to unforeseen operational constraints. Since we have never purchased reserves in the pre-schedule time frame, the team wants to ensure we are ready to go when we do.
- However, recent system condition changes make it entirely possible that BPA could be forced into operational purchases on April 1st.
  - Given this, regardless of need, we plan to make some purchases in early April to test the PO request, acquisition, scheduling, deployment and billing processes related to these pre-schedule acquisitions.
- Should actual operational acquisitions not be required in early April, we would attempt to make four acquisitions during the first half of April to gain invaluable experience with implementing this new process.
- The four Beta test pre-schedule acquisitions proposed are as follows:
  - One 50 MW (24 hour) weekday purchase.
  - One 50 MW (24 hour) weekend purchase.
  - Two 50 MW (24 hour) weekday purchases for the same period.

Preliminary proposal for a Summer pre-schedule pilot

- As referenced earlier, the wind parties in the context of the BP-14 Gen Inputs Rate Case Settlement Workshops have expressed a desire for BPA to test utilizing pre-schedule acquisitions to strategically target high-volatility wind events.
- Prior to agreeing to any pilot, BPA would "dry lab" (test) the R3T model to document its predictive capability for pre-schedule purchase needs.
- The primary objectives of this pilot would be to:
  - Attempt to target acquisitions for high-volatility wind events, thereby potentially improving the level of service.
  - Test the ability to buy capacity in the preschedule timeframe.
  - Obtain pricing data in a capacity constrained market.
  - Provide additional market data for the BP-16 Rate Case.

Wrap up

- Operational Acquisition Beta Test:
  - Absent actual Operational Acquisition needs in early April, our goal for this time period will be to test our pre-schedule acquisition process, including RFO, award & notification, scheduling, deployment, and billing prior to an actual operational need.
  - In the event of actual need, the above processes will be tested in conjunction with that need.
- Proposed Summer Pilot:
  - For the proposed Summer Pilot, we still need to come to internal consensus regarding the forecasting model's readiness, the availability of settlement budget funds, and BPA's willingness to move forward with attempting to acquire in this timeframe.

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Consideration of Separate Public Process for Imbalance Service Rate Case Inputs

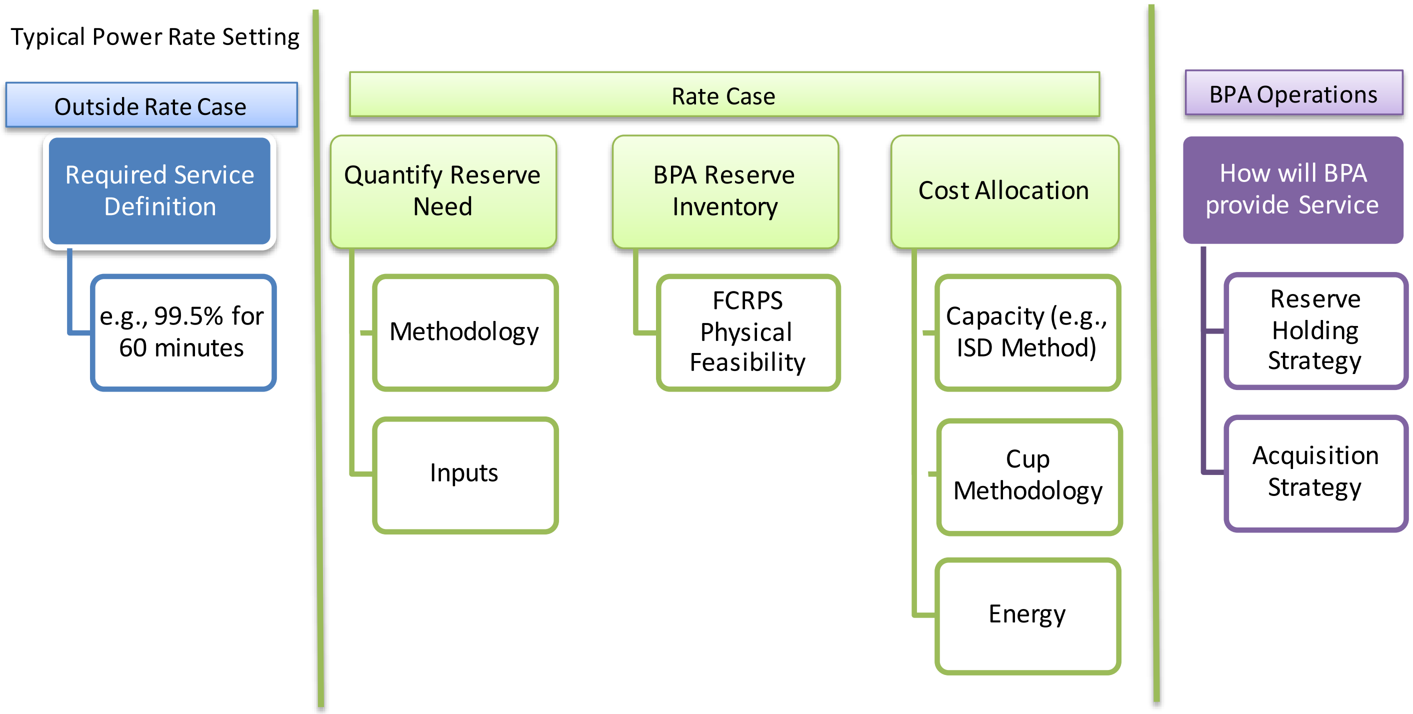
Eric King

Introduction

- As we look to BP-16, BPA needs to decide the process it will use to:
  1. establish the service definition for imbalance service;
  2. establish the methodology to calculate the total quantity of balancing reserve capacity needed to provide imbalance service; and
  3. establish the methodology to determine the quantity of balancing reserve capacity that can be provided for ancillary and control area services from the FCRPS ("physical feasibility").
- BPA must decide whether the service definition and reserve methodologies will be established:
  1. in the rate case subject to rate case procedural requirements; or
  2. in a new public process outside of the rate case.
     a. Process would likely include a formal comment period and a decision document.
- Some of the drivers for change:
  - Simplify the rates process, and
  - Separate tariff terms and conditions from rates.
    - In FERC's November 21, 2013 order on BPA's reciprocity safe harbor tariff, FERC stated that "Bonneville should incorporate the process it intends to use to set the level of imbalance service that it will provide in its OATT and not in individual rate cases."

Discussion

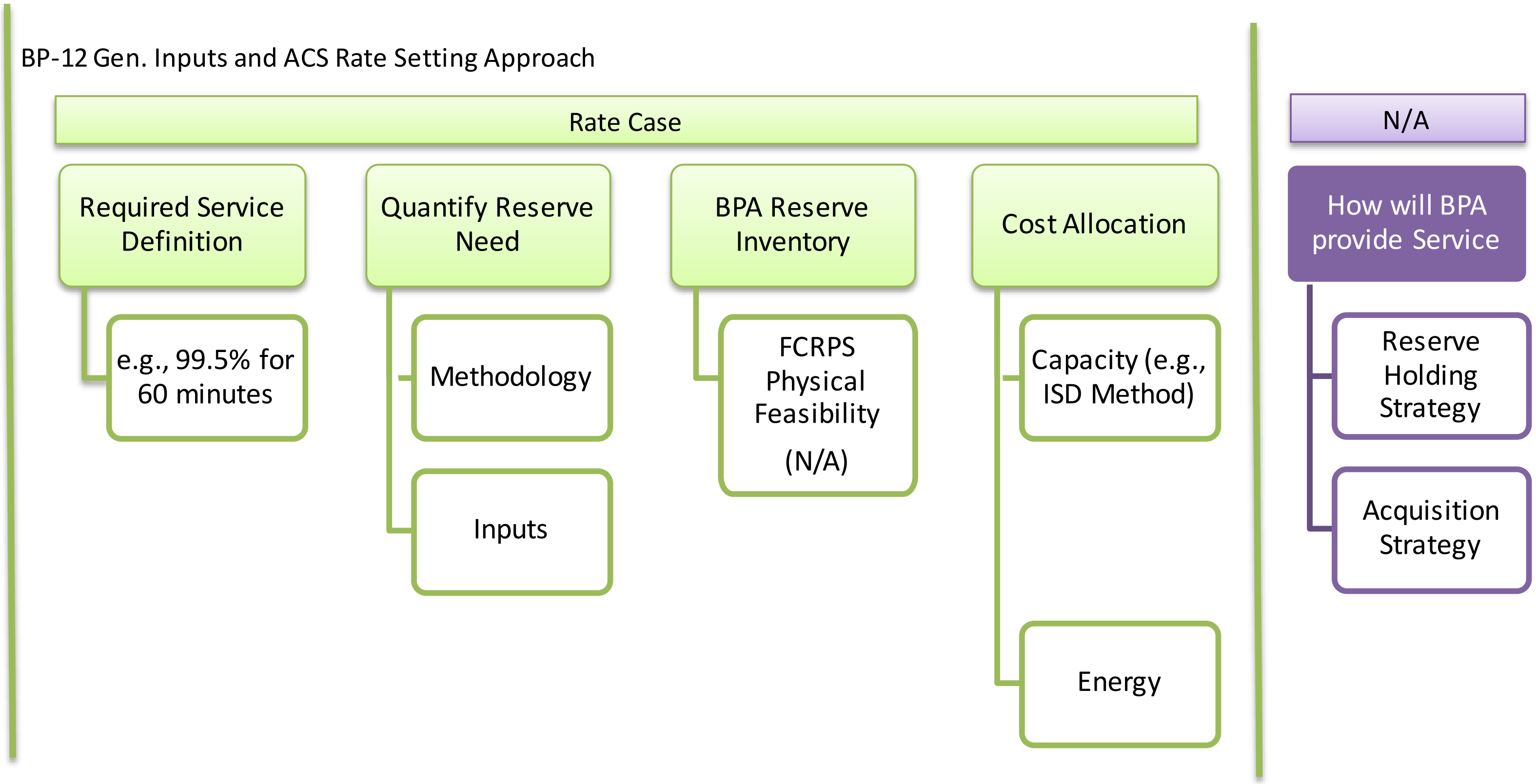
- Prior to BP-12, BPA would normally determine its service definitions before the Initial Proposal so that pricing and cost recovery for those services could be established in the rate case.



- However, BPA has also finalized service definitions after the Initial Proposal, but before the rate case final decision.

BP-12 Gen Inputs

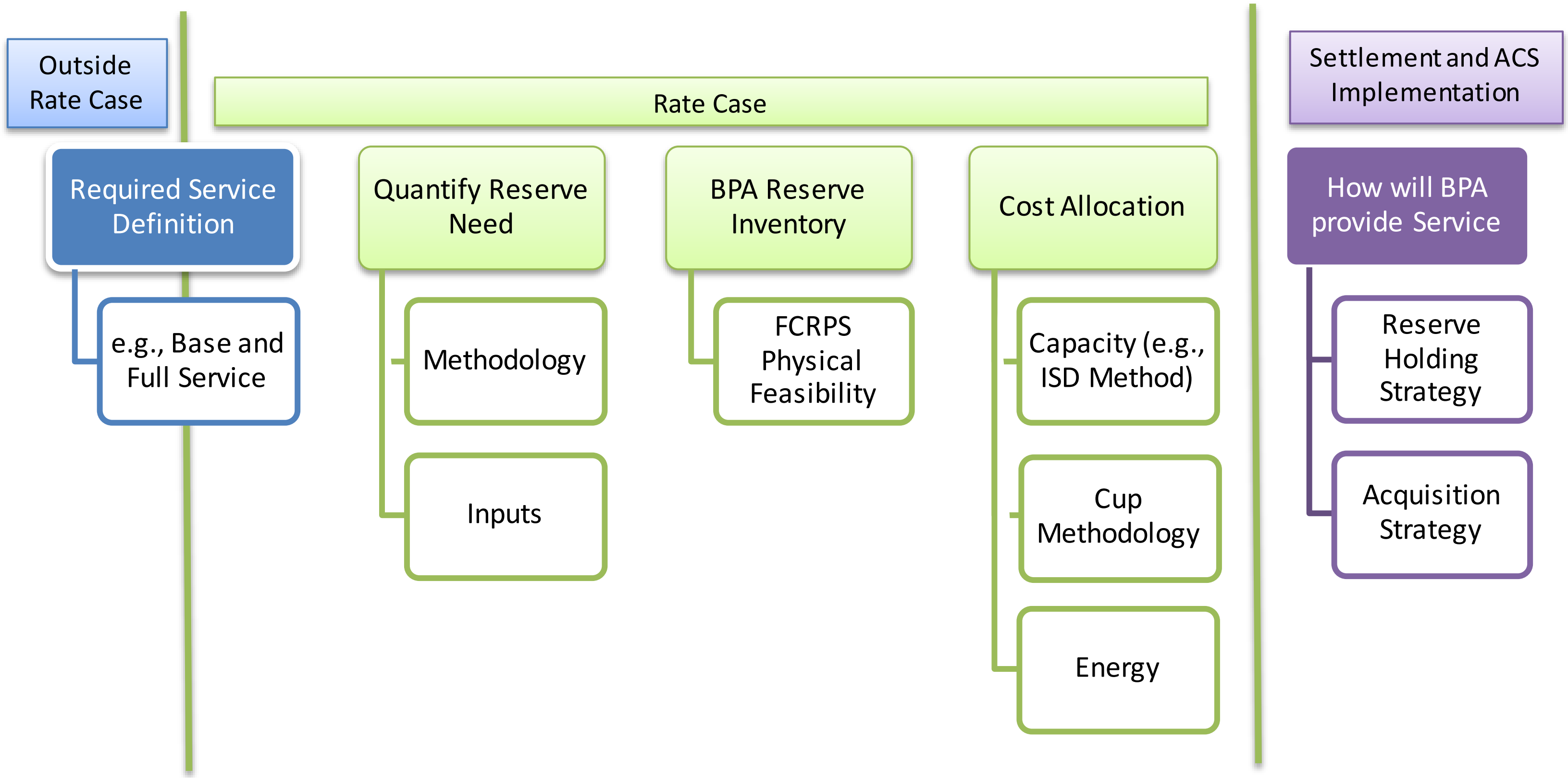
- In BP-12, BPA defined the services fully in the rate case process.



BP–14 Gen Inputs

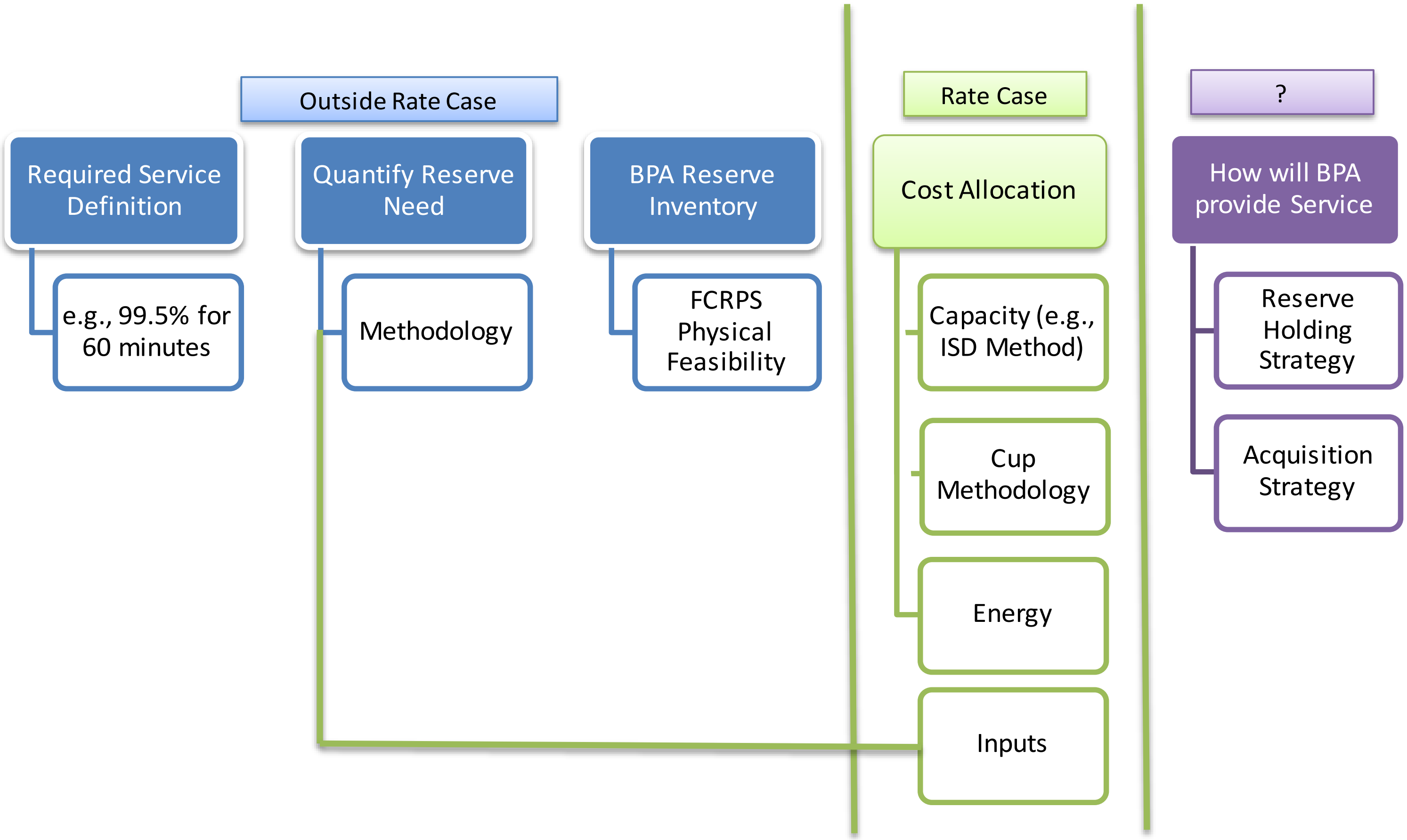
- For BP-14, BPA defined services in a combination of BOATT, ACS and the BP-14 rate case processes.

BP-14 Gen. Inputs and ACS Rate Setting Approach



Potential Future State

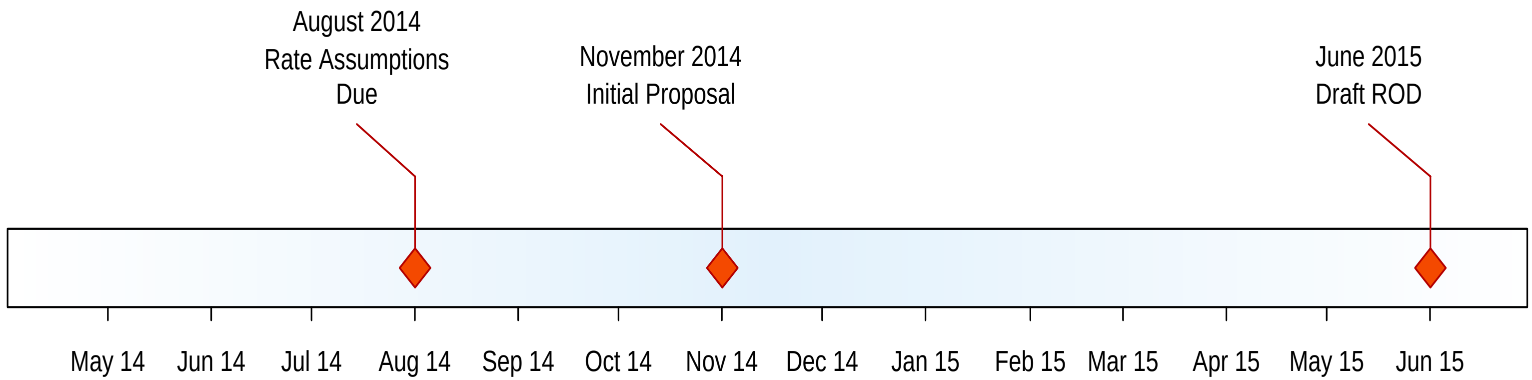
- Going forward, BPA is looking for a sustainable approach that makes sense for determining imbalance service rate case inputs.



Alternatives

- Alternative 1: All issues addressed in the rate case – Utilize section 7(i) process to the extent practicable
- Alternative 2: Separate public process (all else remains in the rate case):
  - Establish the service definition for imbalance service
- Alternative 3: Separate public process (all else remains in the rate case):
  - Establish the service definition for imbalance service
  - Establish the methodology to determine the quantity of balancing reserve capacity that can be provided for ancillary and control area services from the FCRPS ("physical feasibility")
- Alternative 4: Separate public process:
  - establish the service definition for imbalance service;
  - establish the methodology to calculate the total quantity of balancing reserve capacity needed to provide imbalance service; and
  - establish the methodology to determine the quantity of balancing reserve capacity that can be provided for ancillary and control area services from the FCRPS ("physical feasibility")

Potential Timelines



Alt 1: Rate Case	Apr 14 - Jul 14 Rate Case Workshops	Aug 14 - Oct 14 Initial Proposal Drafting	Nov 14 - Jun 15 Formal 7(i)
Alts 2-4: Non-rates	May 14 - Jul 14 Develop proposal	Jul 14 - Oct 14 Formal public process/ comment	Apr 15 - Jun 15 Finalize ROD

Next Steps

- BPA is seeking feedback on the appropriate path forward.
- Send comments to techforum@bpa.gov by April 11.

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Customer Presentations