2010 BPA Rate Case

Pricing Methodology for Generation Inputs
for Regulating Reserves and Wind Integration – Within-Hour Balancing Service

September 23, 2008

Agenda

- 9:00 Welcome and Introductions
- 9:15 Embedded Cost Component for Generation Inputs for Regulating Reserves and Wind Integration – Within-Hour Balancing Service
- 10:30 Break
- 10:45 Stand Ready and Deployment Cost Components for Generation Inputs for Regulating Reserves and Wind Integration – Within-Hour Balancing Service
- 11:45 Next Steps

Key Messages

- We are sharing this material in the spirit urged by regional parties--that of sharing and discussing technical analysis before it is completed--in the interest of a better final product.
- In that spirit, the material we are sharing is very much a work in progress. We are very open to input and willing to make changes based on that input if warranted.
- We note especially that the analysis assumes a "status quo" wind operation. We will work with parties to seek lower-cost means of providing ancillary services for wind, and will point out opportunities where we see them.
- We recognize that this analysis implies a significant increase in charges for ancillary services for integrating wind generation, and the concern this creates for wind project owners. We will work with parties to seek realistic means of lowering the costs.

Pricing Scenarios

- BPA's understanding of various proposed pricing approaches:
  - Public utility customers presented a generation inputs pricing idea in the Tiered Rate Methodology process. They recommended acquiring resources from the market for generation inputs. BPA estimates the cost of generation inputs could range from $12-$20 per kW per month for capacity and the cost to operate that capacity.
  - Some members of the wind community stated in the WI-09 rate case that they should not pay any embedded costs.
- BPA's preliminary thinking includes updating its methodology from the WI-09 proposal to update embedded costs and develop a new method to estimate increased costs to operate the system to provide regulating and following reserves.
- BPA is open to hearing customer input on these and other pricing scenarios.

Objectives for Workshop

- Present BPA's preliminary thinking on pricing generation inputs on regulating reserves and wind integration – within-hour balancing service
- Review the pricing methodology used in the 2007 Power Rate Case for the embedded cost for generation inputs to Regulating Reserves
  - This cost was a part of the Wind Integration - Within-Hour Balancing Service cost in the Wind Integration Rate Case Initial Proposal.
- Present the preliminary pricing methodology for the stand ready and deployment cost components

Definitions

- Wind Integration Within-Hour Balancing Service provides the generation capability to follow within-hour variations of wind resources in the BPA Balancing Authority (BA) to maintain the power system frequency.
- Regulation Reserves (including Load Following) are necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generation control equipment) to follow moment-by-moment changes in load. The obligation to maintain this balance rests with the Balancing Authority (BA).

Definitions

- Following capacity describes the within-hour shifts of average energy and is available within an hour through spinning capacity and non-spinning capacity to meet within-hour variations in forecasted and un-forecasted load and generation.
  - Both regulation and following capacity provide for continuous balancing of resources (generation and interchange) with load within the hour.
- Energy Imbalance is calculated after-the-fact, provides the difference between hourly scheduled load and hourly actual load by customer (energy component that does not address capacity cost of service).
- Generation Imbalance, is calculated after-the-fact, provides the difference between scheduled and actual energy delivered from generation resources inside the BPA BA (energy component that does not address capacity cost of service).
  - Rate Design covering both Energy and Generation Imbalance is intended to encourage accurate scheduling. Currently, wind resources and new generation resources undergoing testing before commercial operation are exempt from band three of generation imbalance.
  - Due to the lack of time and complexity of the reserves forecasting analysis, imbalance impacts were not addressed in the WI-09.

Pricing Principles

- Consistent Allocation of Costs for All Uses of Similar Products/Services
- Cost Causation

Overview of Cost Components

- Embedded costs
- Stand Ready costs
- Deployment costs

Embedded Costs

- Preliminary Approach is to Use Embedded Price Methodology for Regulating Reserves from 2007 Power Rate Case
- Explain Pricing Methodology from 2007 Power Rate Case
- Example of Applying 2007 Pricing Methodology Using Preliminary Reserve Need Quantities and Preliminary Costs for FY2010-2011

Generation Inputs – Overview of FY2007-2009 Embedded Cost Pricing Methodology

- Method used for Regulating Reserves
  - calculate the costs associated with the Big 10 hydro projects and divide those costs by the average annual capacity amount of those same Big 10 hydro projects (adjusted for operating and regulating reserve requirements) and add in an Automatic Generation Control (AGC) adder

Generation Inputs – Embedded Cost Pricing Methodology

- Preliminary Proposed Method for WI-09 Wind Integration - Within-Hour Balancing Service Rate Case
  - Used the base embedded cost for regulating reserves as the embedded cost portion.
  - Replaced AGC (Automatic Generation Control) Adder with other cost components.
  - Rate case was settled.
  - No documentation on the regulating reserve embedded cost in the Wind Integration Rate Case.

FY2007-2009 Regulating Reserve Embedded Cost
Calculating the Capacity Value

(WP-07-FS-BPA-05B, page 19)

		FY2007-09
	Regulating Reserve Assumptions	**Average MWs**
1	**Regulated + Independent Hydro**	**9,217**
2	Total BPA Control Area Reserve Obligation (Line 3 + 4)	690
3	Total Self-Supply and Third Party-Supply Reserve Obligation	310
4	**Total PBL Reserve Obligation**	**380**
5	**Control Area Regulation Requirement.**	**350**
5b	**TBL Regulating Reserves Requirement**	**150**

Regulated Hydro	20,252
Independent Hydro	724
Operational Peaking Adj.	-7,901
Hydro Reserves	-1,049
Federal Hydro Maint.	-2,202
Spinning Reserves	-277
Percent Fed Losses	-329
Total 12 Month Period	9,217.8

Components in Calculating the Capacity Value

- Regulated Hydro is the Instantaneous Peak Capability we are adjusting to get to 120-hour capacity (6 hours/day, 5 days/week, 4 weeks/month)
- Independent Hydro are federal Non-Columbia River Projects
- Operational Peaking Adjustment includes
  - Regulation
  - Load Following Capacity
  - Supplemental (Non-Spinning) Capacity
  - And reflects water conditions such as the new BI-OP (Biological Opinion) and other operating requirements
- Federal Hydro Maintenance includes Planned and Forced Outage Reserve
- Spinning Reserve is based on transmission inputs
- Federal Transmission Losses

Components in Calculating the Capacity Value

- 9217.8 MW represents the120-hour capacity
- 120-hour capacity (6 hours/day, 5 days/week, 4 weeks/month)
- Data for the preliminary capacity amount was taken from the WP-07 Supplemental Rate Case Loads and Resources Study.

FY2007-2009 Regulating Reserve Embedded Cost Calculating the Capacity Value

(WP-07-FS-BPA-05B, page 19)

- Big 10 Hydro Projects (89% of System)
  – Operating and Regulating Reserves Added Back In

	Forecast of Average Hydro Generation System Uses	Average MWs
6	Average Hydro Generation (Line 1) (89% of 9217 = 8203)	9,217
7	Total PBL Reserve Obligation (Line 4)	380
8	Control Area Regulation Requirement (Line 5)	350
	(8203 + 380 + 350 = 8933)	
9	**89% Average Hydro Generation System Uses**	**8,933**

FY2007-2009 Regulating Reserve Embedded Cost
Allocating the Costs

(WP-07-FS-BPA-05B, page 19)

- Allocate Costs

	Factor to Apply to Revenue Requirement	Average MWs
10	Control Area Regulating Requirement (Line 5)	350
11	Total Average Control Area Generation (Line 9)	8,933
12	**Multiplication Factor for Revenue Requirement (Line 10 / Line 11)**	**0.03918**

	Adjusted Revenue Requirement	Average $'s
13	Power Revenue Requirement for Big 10 Hydro Projects	**$670,579,044**
14	Multiplication Factor (Line 12)	3.9180%
15	**Adjusted Revenue Requirement for Regulating Reserves**	**$ 26,273,284**

FY2007-2009 Regulating Reserve Embedded Cost
Allocating the Costs

(WP-07-FS-BPA-05B, page 19)

- Calculating the Per Unit Price
- Calculating the Regulating Reserve Revenue Forecast

		FY07-09
	Per Unit Rate	**Average $'s**
16	Adjusted Revenue Requirement for Regulating Reserves (Line 15) (3.918% * $670MM = $26MM)	$ 26,273,284
17	Total Regulating Reserve Obligation (Line 4) * 12 *1000 (380*12*1000 = 4,560,00 kW)	4,560,000
18	**Per Unit Rate in Kw-Mo (Line 16 / Line 17)**	$ 5.76

	Annual Revenue Forecast for Operating Reserves	**Average $'s**
19	Total TBL Regulating Reserve Obligation (Line 5b)	150
20	Per Unit Rate in Kw-Mo (Line 16 / Line 17)	$ 5.76
20a	AGC Adder	$ 1.55
20b	Total Per Unit Rate (Linw 20 + 20a)	**$ 7.31**
21	**Annual Revenue Forecast (Line 19 * Line 20b *12*1000)**	**$ 13,161,033**

FY2007-2009 Regulating Reserve Embedded Cost 2007 Rate Case Summary of Costs Assigned to Generation Inputs for Regulating Reserves

- Power Revenue Requirement for Big 10 Hydro Projects
- The embedded power-related costs of the relevant hydro projects and associated fish mitigation (BPA direct program, Columbia River Fish Mitigation (Corps of Engineers) and Lower Snake River Compensation Plan).
- Administrative and General (A&G) Expense is Power Marketing, Power Scheduling, Generation Oversight, Corporate Expense and 1/2 Northwest Power Planning Council.
- Three revenue credits are applied.

FY2007-2009 Regulating Reserve Embedded Cost 2007 Rate Case Summary of Costs Assigned to Generation Inputs for Regulating Reserves

(WP-07-FS-BPA-05B, page 18)

Section 4.4.2 - Table 1

Summary of Costs Assigned to TBL for the Generation Input for Regulating Reserves

(x1000)

	Regulating Reserves Generation Input	Average Over Rate Period Subtotals (X000)	Totals (X000)
1	Big 10 Dams		
2	O & M	$ 166,675	
3	Depreciation	$ 66,928	
4	Net Interest	$ 88,949	
5	Planned Net Revenues	$ 26,225	
6	Total Revenue Requirement		$ 348,777
7	Fish & Wildlife		
8	O & M 1/	$ 208,872	
9	Amortization/Depreciation	$ 36,042	
10	Net Interest	$ 35,053	
11	Planned Net Revenues	$ 10,397	
12	Subtotal Fish & Wildlife		$ 290,364
13	A&G Expense 1/		$ 92,349
14	Total Revenue Requirement		
15	Revenue Credits		
16	4h10C (non-operations)	$ 39,917	
17	Colville payment Treas. Credit	$ 4,600	
18	Generation Supplied Reactive Generation Input Cost 2/	$16,394	
19	Subtotal Revenue Credits		$ 60,911
20	Net Revenue Requirement		$ 670,579

1/ Power Marketing, Power Scheduling, Generation Oversight, Corporate Expense and 1/2 Planning Council

2/ Average forecasted revenue for Generation Supplied Reactive over three-year rate period

Example of Applying 2007 Pricing Methodology to Preliminary Reserve Need Quantities and Preliminary Costs for FY2010-2011

- Preliminary Costs for Big 10 Hydro Projects
- Preliminary Quantities of Reserve Need for Regulating Reserves and Wind Integration
- Changes
  - Hydro Projects Located in the BPA Balancing Authority (BA)
  - Transmission Losses on Hydro Projects in the BPA BA

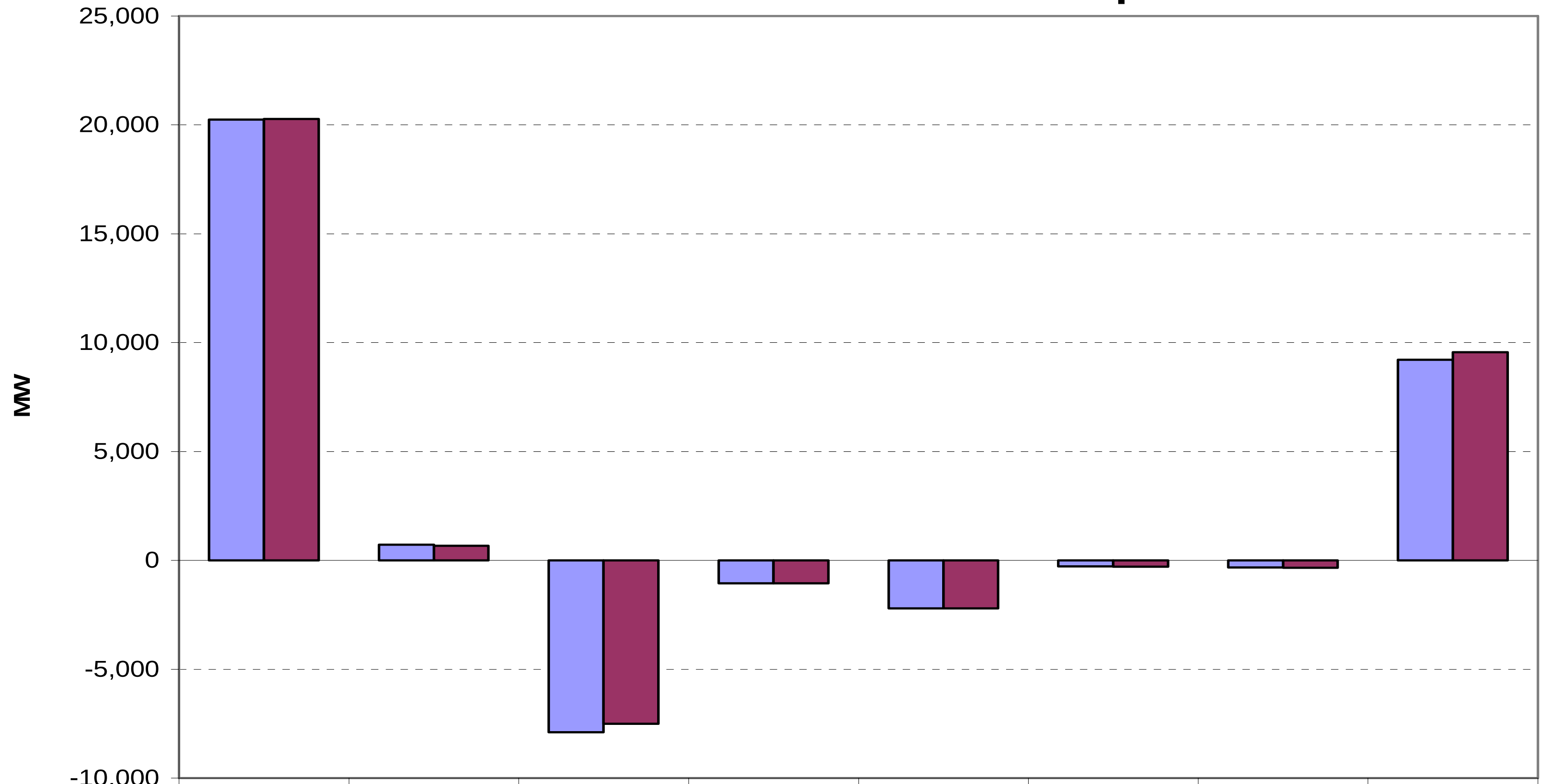
FY2010-2011 Regulating Reserves Embedded Cost Preliminary Update to Assigned Cost

- Current expense estimates are from Power Services Integrated Program Review (IPR) 2010 and 2011 forecasts (pre-decisional).
- Associated plant investment of hydro projects is from original WP-07 forecasts, updated to 2007 actual investment.
- All costs are subject to change for IPR final decisions as well as updates for 2008 actual investments and revised forecasts of plant additions.

FY2010-2011 Regulating Reserves Embedded Cost Preliminary Update to Assigned Cost

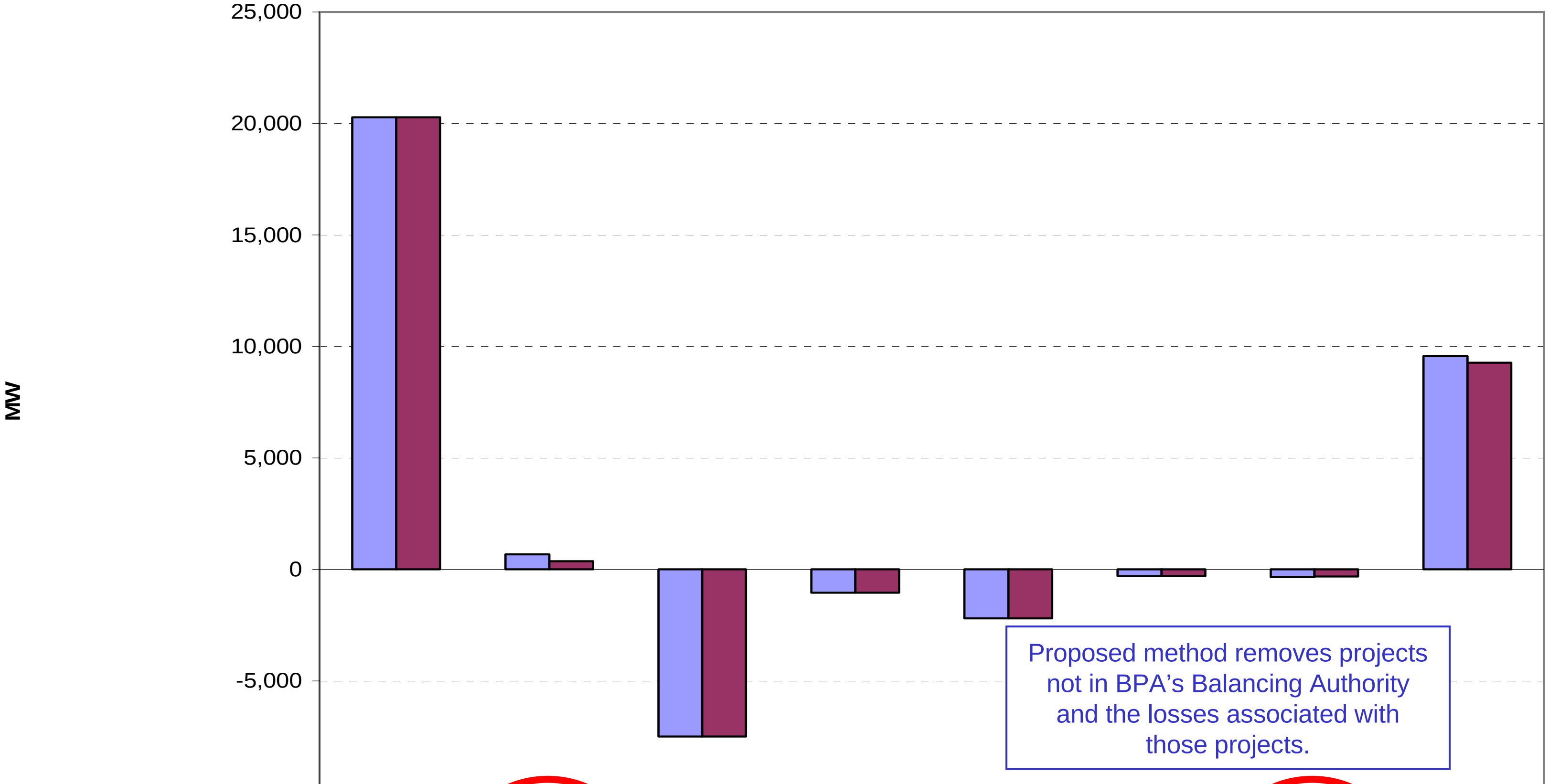
	2010 (X1000)		2011 (X1000)	
Preliminary Regulating Reserves Generation Input Costs	**Totals (X000)**		**Totals (X000)**	
Big 10 Dams	$	365,124	$	369,974
Fish & Wildlife	$	390,256	$	401,694
A&G Expense	$	100,126	$	101,684
Total Revenue Requirement	$	855,506	$	873,352
Revenue Credits	$	71,801	$	70,896
Net Revenue Requirement	**$**	**783,705**	**$**	**802,456**

Comparison of FY 07-09 Generation Inputs to FY 10-11 Generation Inputs



	Regulated Hydro	Independent Hydro	Operational Peaking Adj.	Hydro Reserves	Federal Hydro Maint.	Spinning Reserves	Hydro Federal Trans. Losses	Total 12 Month Average Capacity
FY07-09	20252	724	-7901	-1049	-2202	-277	-329	9218
FY10-11	20268	674	-7497	-1047	-2202	-293	-341	9562

Proposed Update to Federal Transmission Losses and Treatment of Independent Hydro



	Regulated Hydro	Independent Hydro	Operational Peaking Adj.	Hydro Reserves	Federal Hydro Maint.	Spinning Reserves	Federal Trans. Losses	Total 12 Month Average Capacity
FY10-11 using old method	20268	674	-7497	-1047	-2202	-293	-341	9562
Proposed FY10-11	20268	362	-7497	-1047	-2202	-293	-322	9269

Preliminary Reserve Need Quantities from BPA Transmission Services to BPA Power Services

- Regulating Reserves for Load
  - FY2010: 107 MW Regulation + 649 MW Following = 756 MW
  - FY2011: 104 MW Regulation + 607 MW Following = 711 MW
- Wind Integration – Within-Hour Balancing Service
  - FY2010: 27 MW Regulation + 835 MW Following = 862 MW
  - FY2011: 40 MW Regulation + 1188 MW Following = 1228 MW
- Operating Reserves
  - FY2010: 504 MW
  - FY2011: 522 MW

Example for Illustrative Purposes
Embedded Cost Component of Regulating Reserves and Wind Integration Using 2007 Pricing Methodology

		FY10-11
	Regulating Reserve Assumptions	**MWs**
1	Regulated + Independent Hydro	**9,269**
2	Regulating Reserves	**106**
3	Operating Reserves from Big 10	**513**
4	Load Following Capacity	**628**
5	Wind Integration	**1,045**
	Forecast of Big 10 Hydro Capacity System Uses	**MWs**
6	Big 10 Hydro Projects Capacity (Line 1 * 91%)	**8,435**
7	Total PBL Reserve Obligation (Line 2+3+4+5)	**2,292**
8	Big 10 Hydro Project Capacity System Uses (Line 6+7)	**10,727**
	Adjusted Revenue Requirement	
9	Power Revenue Requirement for Big 10 Hydro Projects	**$793,081,000**
10	Big 10 Hydro Project Capacity System Uses (Line 9)	**10,727**
11	Total kW/month Big 10 Hydro Project Capacity (Line 10 * 12MO * 1000kW/MW)	**128,721,480**
12	**Per Unit Allocation $/kW/month (Line 9 / Line 11)**	**$6.16**

Example for Illustrative Purposes
Embedded Cost Component of Regulating Reserves and Wind Integration Using 2007 Pricing Methodology

- Applying preliminary revenue requirement (preliminary Integrated Program Review) and preliminary reserve need quantity (Transmission Services' reserve need forecast from 10 September workshop)
  - Amount of Regulating Reserves
    - 106 MW Regulating Reserves
    - 628 MW Load Following
    - Total is 734 MW
  - Amount of Wind Integration – Within-Hour Balancing Service
    - Total is1045 MW
  - Adjusted Revenue Requirement for Regulating Reserves and Wind Integration
    - $793,081,000
  - Embedded Component Per Unit Reserve
    - $6.16 per kW per month
  - Regulating Reserve Revenue Forecast
    - 106 MW * $6.16/kW/month * 12 months * 1000 kW/MW = $7,835,520 per year
  - Wind Integration – Within-Hour Balancing Service Reserve Revenue Forecast
    - 1045 MW * $6.16/kW/month * 12 months * 1000 kW/MW = $77,246,400 per year

Embedded Cost Portion of Regulating Reserves and Wind Integration – Within-Hour Balancing Service

- Key Drivers for Higher Per-Unit Cost
  - Increased Costs in the Revenue Requirement
  - Higher proportion of reserve need quantity to system capacity

Outline

- Overview of Operational cost of reserves.
- Specific cost associated with standing ready to provide as well as providing reserves.
- How the costs are modeled.
- Preliminary results for the total cost as well as the component costs.

Operational Cost of Reserves

- Costs associated with setting up the system to stand ready and respond to reserve need.

- All reserves are referred to as "inc" or "dec" obligations.

  - Inc Reserve: ability to increase generation in order to maintain load-resource balance in the Balancing Authority Area (BAA).

  - Dec Reserve: ability to decrease generation in order to maintain load-resource balance in the BAA.

- All costs are operations related and do not include items such as operations and maintenance (O&M).

- There are two broad categories of cost:
  1. Stand Ready.
  2. Deployment.

Operational Cost of Reserves

- Stand ready: Those costs associated with making the reserve available such that the system is capable of instantaneously maintaining load-resource balance 99.5% of the time. Stand ready costs consist of:

  1. Energy shift.
  2. Efficiency loss.
  3. Cycling cost.
  4. Spill cost.

- Deployment: Those costs associated with using the reserve in response to the system's need to maintain load-resource balance. Deployment costs consist of the following:

  1. Deployment losses.
  2. Incremental energy shift.
  3. Incremental cycling.
  4. Incremental efficiency loss.

Stand Ready

- Energy Shift: The amount of additional energy moved into light load hours (LLH) in order to meet a dec obligation.
- Efficiency Loss: Efficiency losses are the losses incurred when a project needs to alter its unit dispatch in order to have enough inc and dec capability standing ready to respond.
- Cycling Cost: The cost of synchronizing and ramping additional units in order to have enough inc and dec capability standing ready to respond.
- Spill Cost: Costs realized when a project must spill energy in order to have enough inc capability standing ready to respond.

Deployment

- Deployment Losses: Efficiency losses realized as reserves are deployed in response to a need.
- Incremental Energy Shift: Costs realized when the reserves deployed exceed the system's dec obligation causing additional energy to be shaped out of the heavy load hour (HLH) period.
- Incremental Efficiency Losses: Additional efficiency losses realized when the reserves deployed exceed the system's inc or dec obligation and the project must redeploy units in order to respond.
- Incremental Cycling Cost: Additional cycling costs realized when the reserves deployed exceed the system's inc or dec obligation and the project must redeploy units in order to respond resulting in additional units being brought on/off-line.

The Model

- Price reserves in a more robust fashion, relative to WI-09, to capture the impact of carrying reserves.

- General method is to model the dispatch of controller projects over the 70-year data set for each month based on a HYDSIM run.

  1. Shape HYDSIM energy into HLH and LLH generation for Grand Coulee, Chief Joseph, John Day, and The Dalles.

  2. Dispatch units with the objective of maximizing plant efficiency for each given generation level.

  3. Calculate available reserves and compare to reserve obligation.

  4. Redeploy units at projects as needed in order to meet reserve obligation.

Stand Ready: Energy Shift

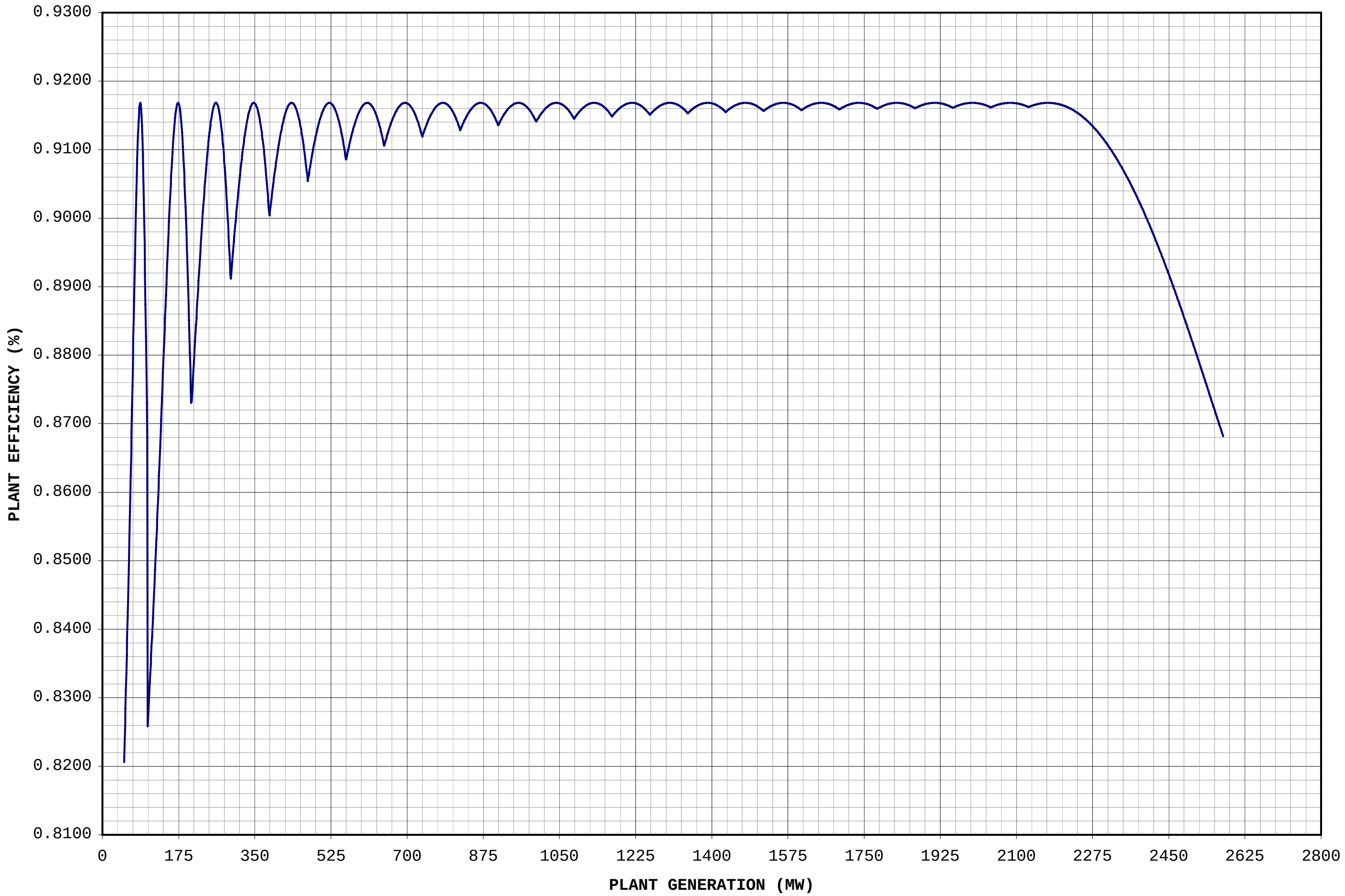
- The amount of additional energy moved into light load hours (LLH) in order to meet a dec obligation and/or to unload units to meet inc obligation.
- Energy shift impacts are calculated by taking a LLH generation request (a HYDSIM energy value shaped into LLH) and increasing generation above the request so sufficient dec regulation capability exists.
- The LLH generation request is the minimum amount of energy that must be moved through a project.

Stand Ready: Efficiency Loss

- Efficiency losses are incurred when projects alter their unit dispatch in order to have enough inc and dec capability standing ready to respond.
- Projects are standing ready to respond; not responding at this point.
- The loss is determined by finding the most efficient unit dispatch for each controller project meeting both the generation request and reserve obligation for a base case and a test case. The loss is determined by taking the efficiency difference between the test and base case.
- The loss is valued at the AURORA HLH price.

Stand Ready: Efficiency Loss

- Begin by finding the optimal efficiency for a given level of generation.



Stand Ready: Efficiency Loss

- For example: assume the plant load is 1228 MW. Given the previous plant efficiency curve, the most efficient unit dispatch resulting in 1228 MW of generation yields an efficiency value of 91.67%.

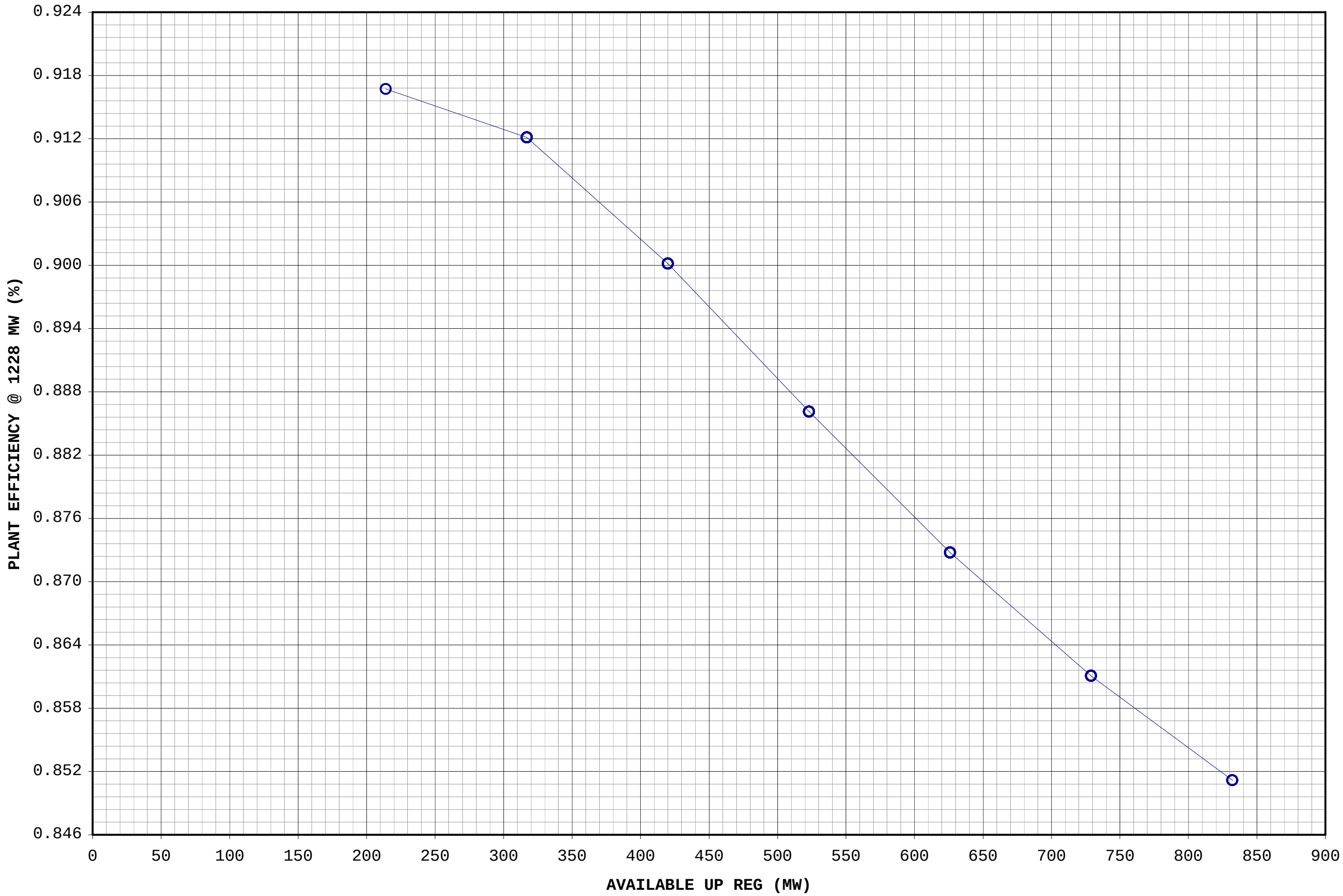
- There are 14 units online and available inc reserves of 214 MW.

- Any inc obligation less than or equal to 214 MW will result in no efficiency loss.

- If the plant must stand ready to inc by more than 214 MW, efficiency losses are realized.

Stand Ready: Efficiency Loss

- Plant efficiency declines with an increasing reserve obligation.



Stand Ready: Efficiency Loss

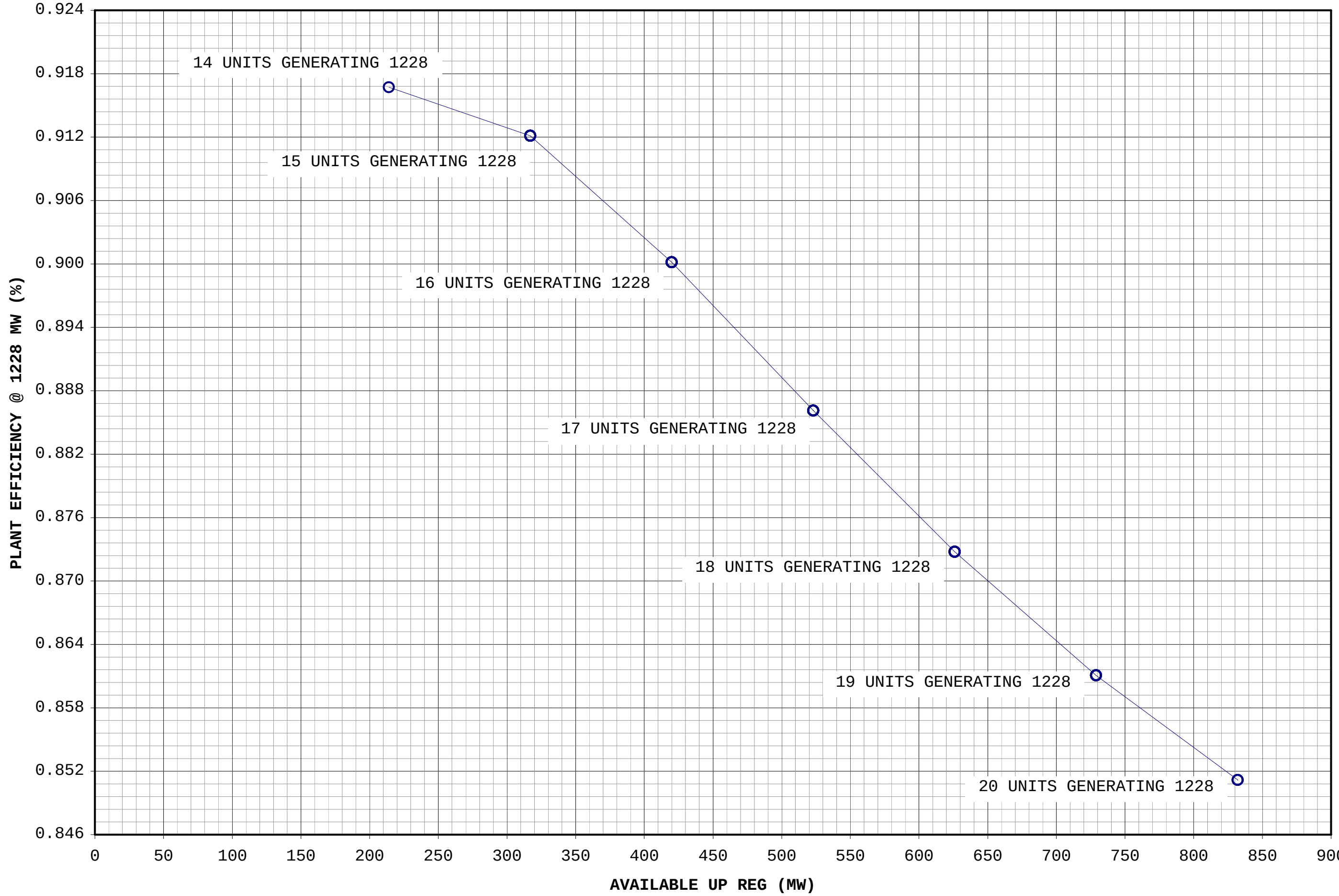
- If the plant must stand ready to provide 500 MW of inc, plant efficiency drops to 88.61% from a peak value of 91.67%.
- The plant's efficiency loss is 3.06% (88.61% - 91.67%).
- 38 MW (3.06% * 1228 MW) of generation is lost.
- For each hour that the plant is standing ready to provide up to 500 MW of regulation inc while generating 1228 MW, 38 MW of energy is lost to an inefficient dispatch.
- The lost energy is valued at the AURORA HLH price.

Stand Ready: Cycling Cost

- Continuing with the current example of a project generating 1228 MW while standing ready to provide up to 500 MW of inc.
- In addition to the losses in efficiency are costs associated with cycling more units on/off line.
- At peak efficient operation for 1228 MW of generation, the project has 14 units online.
- In order to meet its reserve obligation, the plant must have 17 units online.
- Current per-cycle cost estimate is $123/cycle for synchronization and ramping losses.

Stand Ready: Cycling Cost

- Units online increase with an increasing reserve obligation.



Stand Ready: Spill Cost

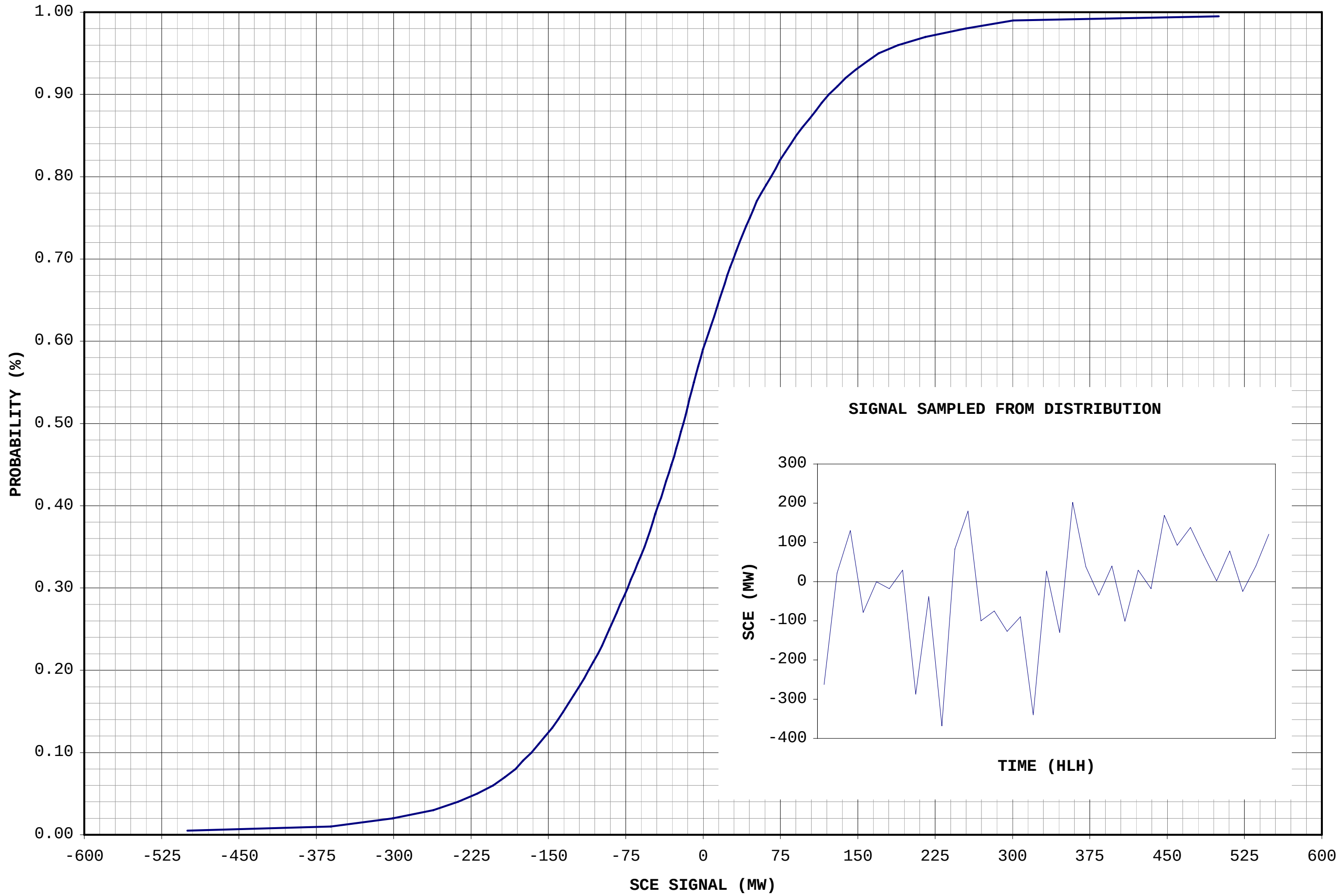
- Spill costs are realized when an inc obligation combined with a generation request results in all available units being online and still unable to meet the inc reserve obligation.
- In this case the units are unloaded to just meet the inc obligation and the project spills the remaining energy.
- Spilled energy is valued at the AURORA HLH price.

Deployment: Deployment Loss

- All previous discussion on cost has dealt with setting up a project with the ability to respond.
- Additional costs are incurred when the project actually responds to an error signal.
- The first step to capturing deployment costs is to simulate an error signal.
- After simulating a signal, model the project's response to the signal and calculate the net of the efficiency gains and losses during deployment.
- Deployment losses are valued at the AURORA HLH price.

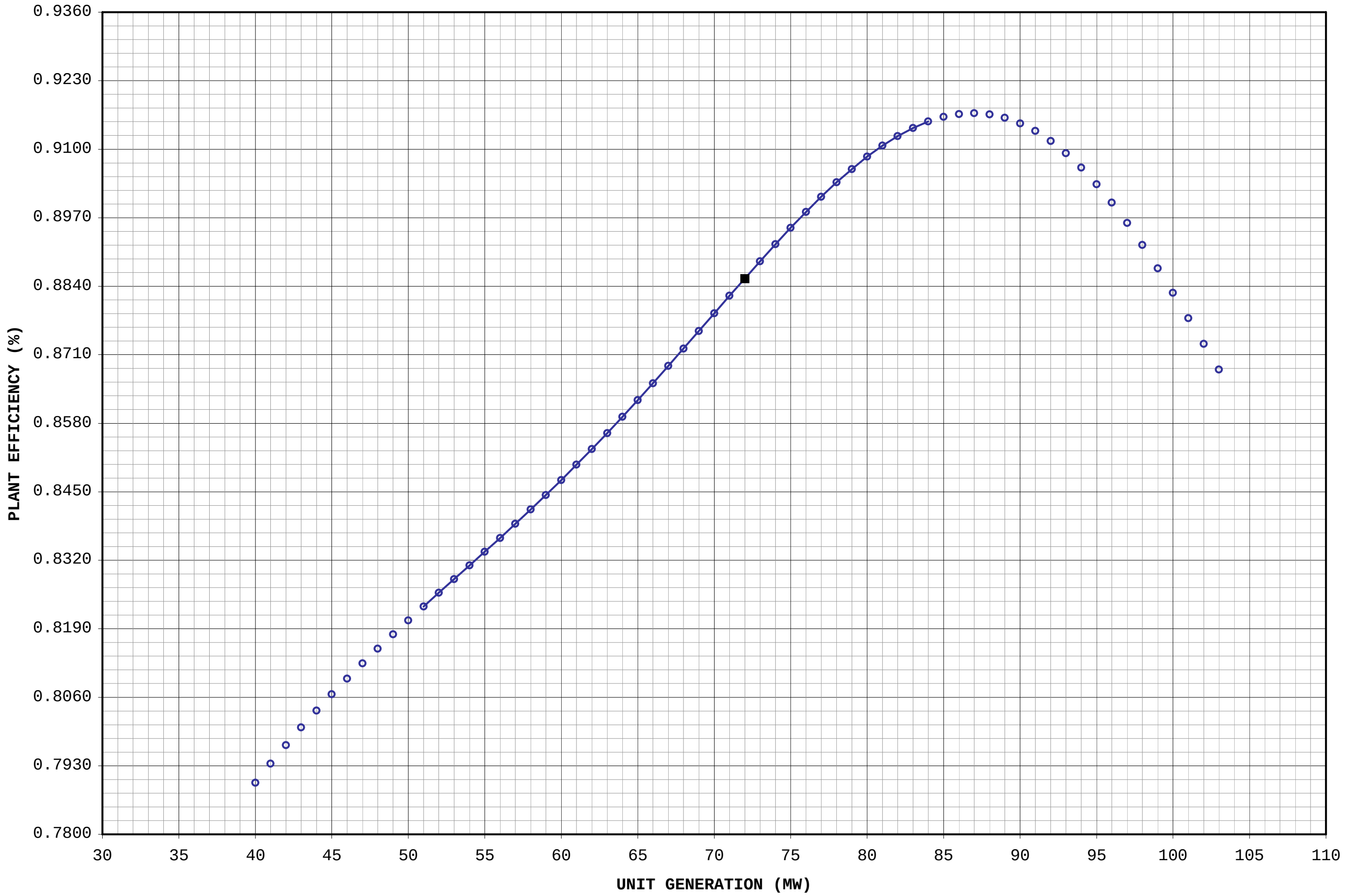
Deployment: Deployment Loss

- Reserve need simulation.



Deployment: Deployment Loss

- Project's units respond to error signal; integrate to calculate loss.



Deployment: Deployment Loss

- As the project's units respond efficiency gains and losses are realized.
- As the error signal is received, the average change in efficiency is calculated by integrating over the interval of unit movement.
- Multiplying the average change in efficiency by the average generation while responding yields the efficiency loss in terms of MW.
- For example:
  - Generating at 1228 MW, 17 units online (~72 MW/unit), and efficiency at 88.61% the project is ready to respond up to 500 MW.
  - An SCE signal of -263 MW is received; each unit must now back down to ~57 MW.

Deployment: Deployment Loss

- For example (cont.):
  - Integrating along the efficiency curve from 72 MW down to 57 MW yields an average efficiency of 86.13%; a loss of 2.48%.
  - Average generation over the response is 1097 MW resulting in a loss of 27 MW (1097 MW * 2.48%).
  - Repeat the process for each water year for each HLH and LLH period.
  - The simulation currently iterates 1000 times for both the HLH and LLH periods of each month.
  - Goal is to get sufficient sample of 1 minute error signal over the month.

Deployment: The Incrementals

- For those instances where the simulated reserve need (the error signal) exceeds the project's reserve obligation; incremental costs are incurred as the projects move to meet the signal.

- Since the reserve obligation is based on a 99.50% exceedance probability, incremental cost are incurred, at most, with a 0.50% probability.

- There are three identified incremental costs:
  - Incremental energy shift,
  - Incremental cycling, and,
  - Incremental efficiency loss.

Deployment: Incremental Energy Shift

- Incremental energy shift costs may be realized if an error signal exceeds the system's ability to dec.
- For purposes of modeling, it is assumed that additional load can be found (marketed) allowing the project to sufficiently dec.
- The incremental energy shift is valued at the AURORA HLH-LLH price differential.

Deployment: Incremental Cycling

- Incremental cycling costs may be realized if an error signal exceeds the system’s ability to inc or dec.
- Additional units being placed on or off-line in order to meet the error signal result in an incremental cost.
- The cycles are valued at $123 per cycle.

Deployment: Incremental Efficiency Loss

- Incremental efficiency losses may be realized if an error signal exceeds the system's ability to inc or dec.
- As units are being placed on or off-line in order to meet the error signal the project's operating efficiency is altered resulting in incremental losses.
- The incremental losses are valued at the AURORA HLH price.

Results

- The following results, showing the total and all sub-components, are first-run and indicative only.

- The results do not include embedded cost.

Results: Total

- The following table shows the total cost for various combinations of inc and dec reserve obligation:

TOTAL	0 MW	500 MW	1000 MW	1500 MW	2000 MW
0 MW	0	-3,929,261	-15,927,855	-35,539,794	-59,924,888
-500 MW	-16,075,821	-19,180,286	-30,288,028	-49,894,692	-74,697,623
-1000 MW	-31,898,170	-34,519,079	-44,949,061	-64,180,132	-89,378,545
-1500 MW	-47,736,001	-50,275,466	-59,925,043	-78,629,097	-104,095,491
-2000 MW	-63,837,544	-66,017,218	-75,187,642	-93,409,013	-119,342,653

Results: Stand Ready Components

- The following table shows the energy shift cost component for various combinations of inc and dec reserve obligation:

ENERGY SHIFT	0 MW	500 MW	1000 MW	1500 MW	2000 MW
0 MW	0	0	0	0	0
-500 MW	-15,194,749	-15,194,749	-15,194,749	-15,194,749	-15,194,749
-1000 MW	-30,389,498	-30,389,498	-30,389,498	-30,389,498	-30,389,498
-1500 MW	-45,584,247	-45,584,247	-45,584,247	-45,584,247	-45,584,247
-2000 MW	-60,778,996	-60,778,996	-60,778,996	-60,778,996	-60,778,996

Results: Stand Ready Components

- The following table shows the efficiency loss component for various combinations of inc and dec reserve obligation:

EFFICIENCY LOSS	0 MW	500 MW	1000 MW	1500 MW	2000 MW
0 MW	0	-3,133,845	-14,046,439	-31,495,783	-51,085,832
-500 MW	-350,313	-2,944,864	-13,172,864	-30,498,054	-50,404,600
-1000 MW	-735,979	-3,022,430	-12,371,322	-29,410,604	-49,591,582
-1500 MW	-1,185,818	-3,142,866	-11,890,650	-28,494,161	-48,606,742
-2000 MW	-1,669,272	-3,401,351	-11,718,654	-27,512,820	-47,822,883

Results: Stand Ready Components

- The following table shows the cycling cost component for various combinations of inc and dec reserve obligation:

CYCLING COST	0 MW	500 MW	1000 MW	1500 MW	2000 MW
0 MW	0	-690,880	-1,459,722	-2,267,595	-3,819,462
-500 MW	-516,426	-929,008	-1,494,199	-2,425,381	-4,078,918
-1000 MW	-742,130	-983,260	-1,752,308	-2,597,557	-4,266,003
-1500 MW	-918,965	-1,411,165	-2,002,446	-2,650,981	-4,449,465
-2000 MW	-1,325,956	-1,686,978	-2,122,959	-2,893,457	-4,603,937

Results: Stand Ready Components

- The following table shows the spill cost component for various combinations of inc and dec reserve obligation:

SPILL	0 MW	500 MW	1000 MW	1500 MW	2000 MW
0 MW	0	-81,689	-380,387	-1,727,079	-4,964,172
-500 MW	0	-81,689	-380,387	-1,727,079	-4,964,172
-1000 MW	0	-81,689	-380,387	-1,727,079	-5,074,055
-1500 MW	0	-81,689	-380,387	-1,836,962	-5,392,557
-2000 MW	0	-81,689	-490,270	-2,155,463	-6,072,961

Results: Deployment Components

- The following table shows the deployment loss component for various combinations of inc and dec reserve obligation:

DEPLOYMENT LOSS	0 MW	500 MW	1000 MW	1500 MW	2000 MW
0 MW	0	-14,142	-25,338	-36,534	-44,782
-500 MW	-10,683	-18,366	-26,049	-33,732	-41,415
-1000 MW	-23,368	-27,698	-32,028	-36,359	-40,689
-1500 MW	-36,052	-37,632	-39,212	-40,791	-42,371
-2000 MW	-48,737	-46,683	-44,630	-42,576	-40,522

Results: Deployment Components

- The following table shows the incremental energy shift component for various combinations of inc and dec reserve obligation:

INC ENERGY SHIFT	0 MW	500 MW	1000 MW	1500 MW	2000 MW
0 MW	0	0	0	0	0
-500 MW	-2,813	-2,813	-2,813	-2,813	-2,813
-1000 MW	-5,596	-5,596	-5,596	-5,596	-5,596
-1500 MW	-8,399	-8,399	-8,399	-8,399	-8,399
-2000 MW	-11,221	-11,221	-11,221	-11,221	-11,221

Results: Deployment Components

- The following table shows the incremental cycling cost component for various combinations of inc and dec reserve obligation:

INC CYCLE COST	0 MW	500 MW	1000 MW	1500 MW	2000 MW
0 MW	0	-3,457	-10,205	-6,778	-4,614
-500 MW	-848	-3,512	-11,141	-6,863	-4,934
-1000 MW	-1,628	-3,662	-12,024	-7,418	-5,108
-1500 MW	-2,543	-4,236	-13,735	-7,525	-5,672
-2000 MW	-3,225	-4,614	-14,700	-8,237	-5,945

Results: Deployment Components

- The following table shows the incremental efficiency loss component for various combinations of inc and dec reserve obligation:

INC EFF LOSS	0 MW	500 MW	1000 MW	1500 MW	2000 MW
0 MW	0	-5,248	-5,764	-6,024	-6,024
-500 MW	10	-5,285	-5,827	-6,021	-6,021
-1000 MW	27	-5,246	-5,897	-6,022	-6,014
-1500 MW	23	-5,233	-5,968	-6,031	-6,039
-2000 MW	-136	-5,685	-6,213	-6,243	-6,188

Next Steps