Building the Framework for the Integrated Program Review

January 31, 2012

To participate via phone, please dial 866-324-4184
When prompted, enter access code **6352333**.

Introduction

- Welcome to an advance discussion before the Integrated Program Review responding to your request for an early conversation on expectations and strategies.
- We are looking forward to a high-level strategic discussion including an overview of programs, future costs and rates, and an opportunity to gain your perspective before the upcoming process.
- This discussion today is not about “the numbers.” The 2010 IPR data are out-dated and will change. We want to talk about the drivers.

Agenda

January 31, 2012 from 10:00 to 5:00 pm

Introduction	**Steve Wright**
Economic Outlook	**Mark Roberts**
General Manager Panel	**Bill Drummond**
Lunch	**~**
Strategic Rate Drivers & Audience Dialogue	**Steve Wright**
– Power & Generation Inputs	**Greg Delwiche**
– Transmission	**Brian Silverstein**
– Finance	**Claudia Andrews**
Closing Remarks	**Steve Wright**
– What We Heard	
– Where We Go From Here	

Economic Outlook

Separate Handout

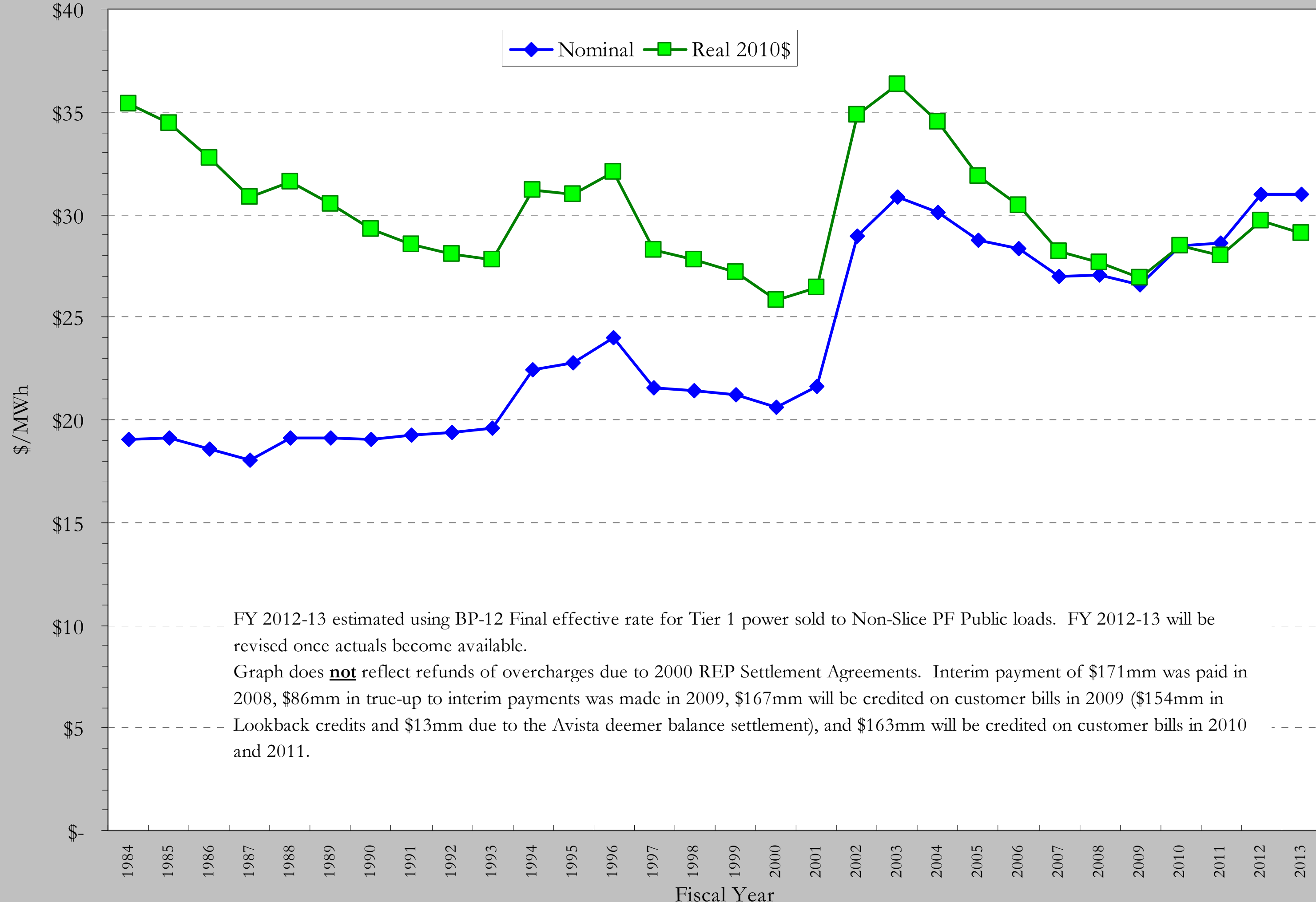
Strategic Drivers for Rates

Introduction to Strategic Rate Drivers

- The morning session shared information and perspectives on the national and regional economy.
- The afternoon session will share the strategic challenges confronting BPA as we embark on the next Integrated Program Review and subsequent rate setting process.
- Your input on these types of issues and how you are handling them at your utility will be valuable as we proceed.

Power Services

Historical Priority Firm Power Rates - No Transmission FY 1984-2013



Deflators for 1984-2010 from Bureau of Economic Analysis - Table 1.1.9. Implicit Price Deflators for Gross Domestic Product; 2011-13 estimated with 5-year average

Power Rates

Forecast Assumptions FY 2014/15

- **Revised gas price forecast and updated forecast of net secondary revenues**
  - Updated electricity market price forecast incorporates 1) lower gas prices, and 2) a revised spring price forecast.
  - Both of these changes yield lower anticipated net secondary revenues.
- **2010 IPR Spending Levels with 10% Capital Reduction**
  - Capital spending levels assume a shaped 10% reduction from “August Base Case” from the Capital Planning discussions in Fall 2011.
  - Interest rates and all other assumptions are consistent with BP-12.
  - Sources of funding are not modeled.

Note: 2010 data are from a two year old forecast for a period up to three years into the future, so it is merely a starting point for IPR discussions.

Power Rate Drivers

There are two main drivers of Power rates - Net Secondary Revenues and Program Expenses:

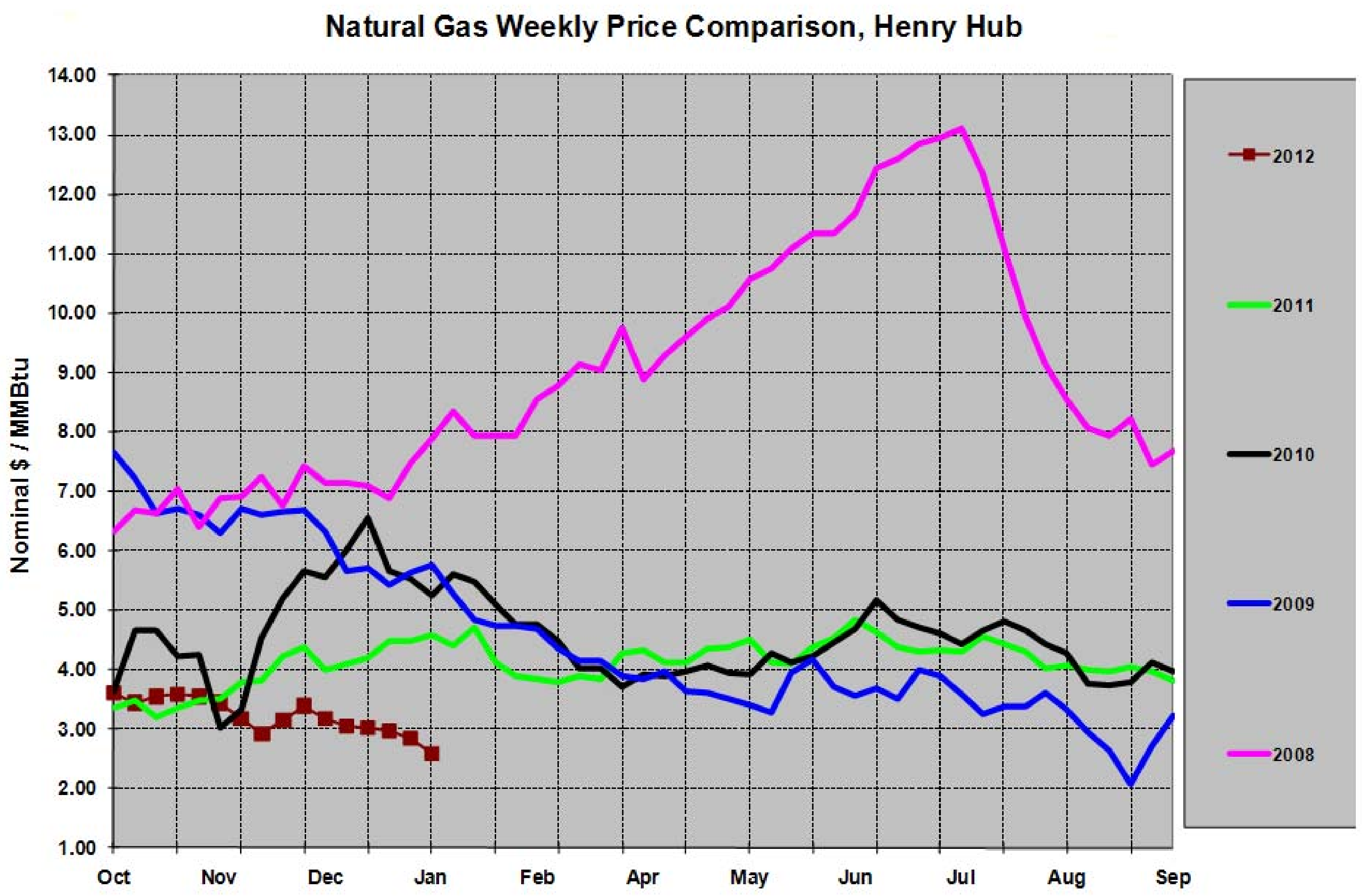
- **Net Secondary Revenues (-$95 million[1/])**
  - Expected persistence of low gas prices yields depressed net secondary revenue forecast.
  - Fundamentals can change between now and when rates are set.
  - Current estimated uncertainty in anticipated net secondary revenues is significant, with a median estimate of $320 million, and ranging from $150 million and $700 million.[2/]

- **Program Expenses to establish in the IPR Process (+$130 Million)**
  - In managing program expenses, our objective is to identify the appropriate balance between near-term rate effects and sustaining the long-term value of the FCRPS generating assets, while also meeting our statutory obligations.
  - Increases in Energy Northwest and Corp of Engineers expenses have the largest influence on rates, followed by Debt Service and Fish and Wildlife.

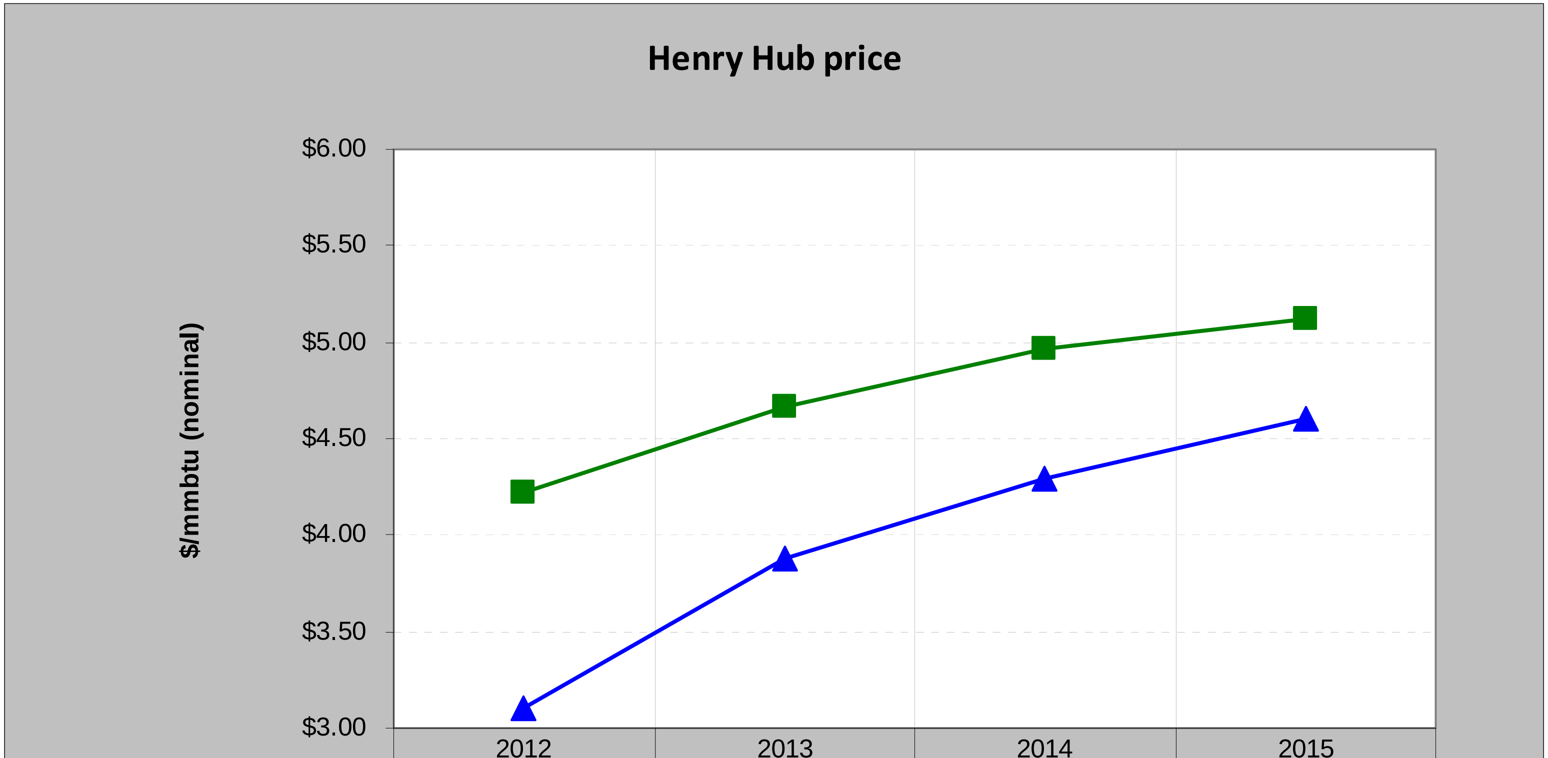
1/ Gas price revision in late January; this number is estimated using a Rule of Thumb applied to roughly 9% lower net secondary, and 6% lower Augmentation expenses due to recent gas price movements in the forward market.

2/ There is a 5% probability of higher revenues, and another 5% probability of lower revenues, outside of this range.

Historical Gas Prices

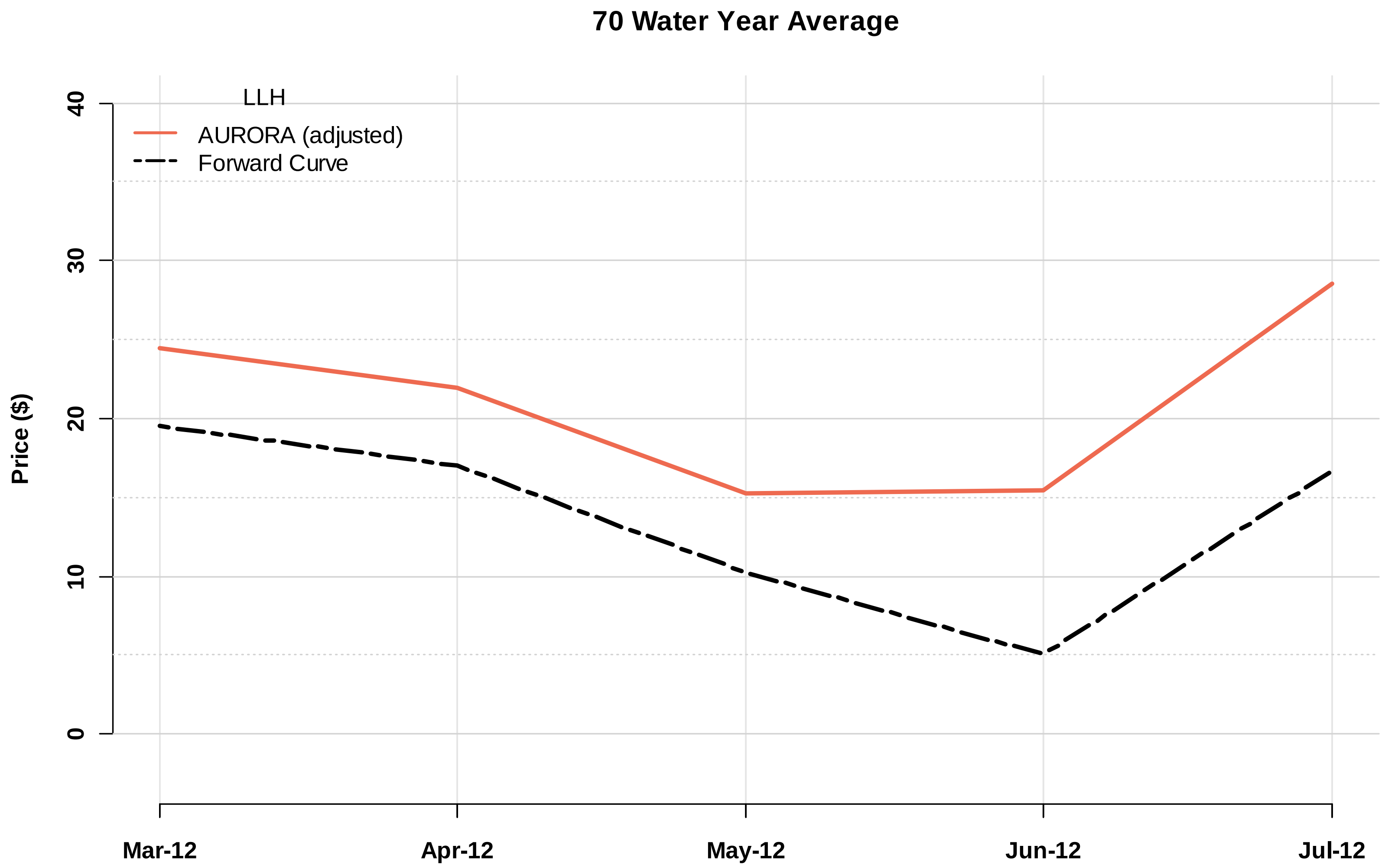


Net Secondary Driver: Change in the Natural Gas Price Forecast

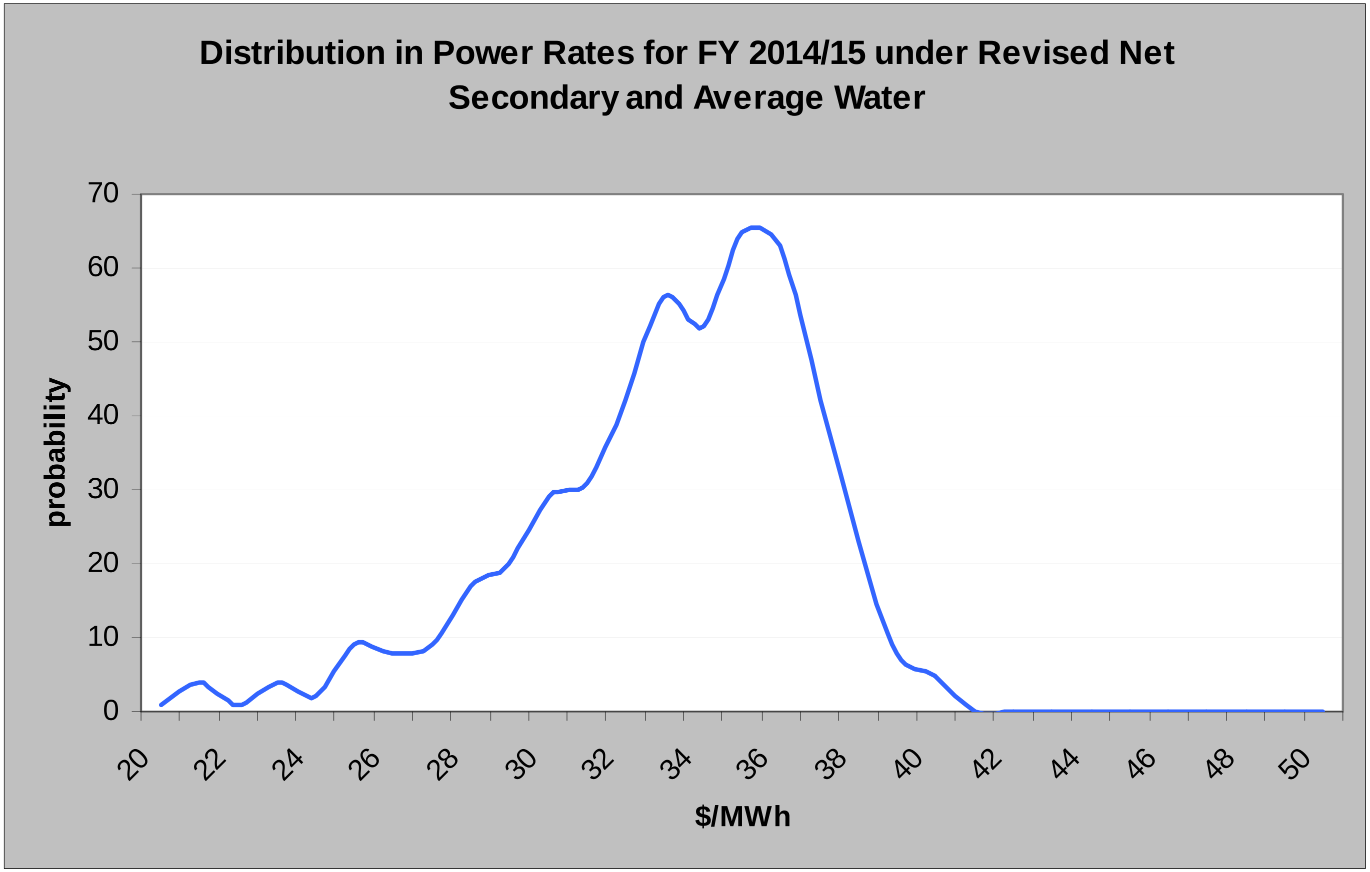


	2012	2013	2014	2015
BPA (1/24/12 update)	$3.10	$3.88	$4.30	$4.60
BPA (BP-12 FS)	$4.22	$4.67	$4.96	$5.12

Net Secondary Driver: Spring Market Prices

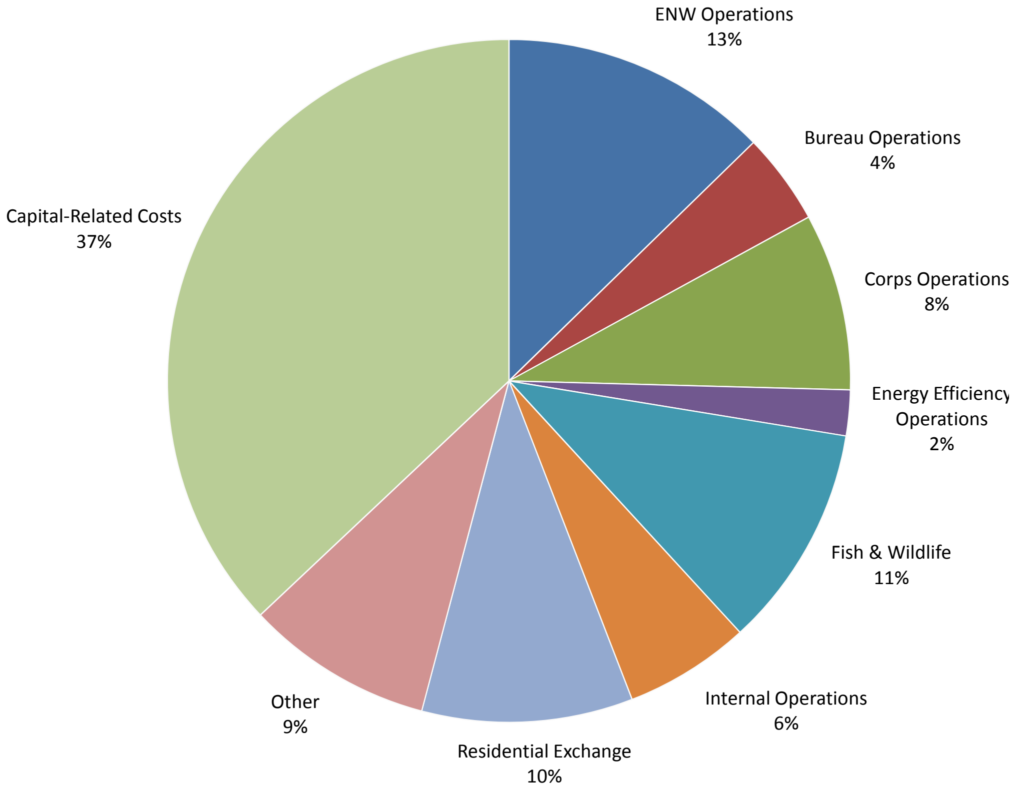


Net Secondary Driver: Power Rate Variability

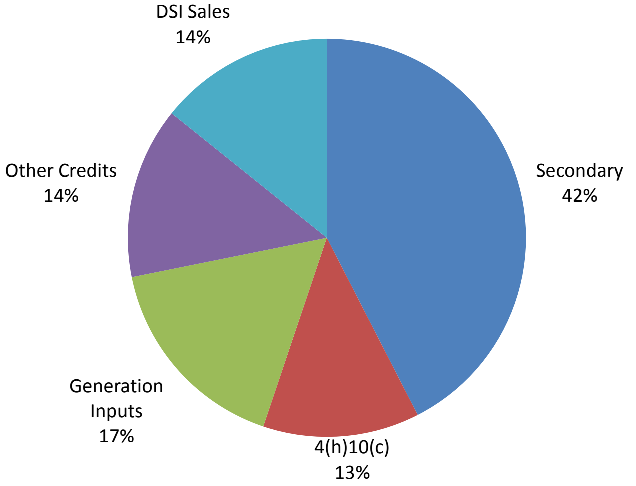


Expense Driver: Power Revenue Requirement

Expenses



Credits



Note: For FY 2014/15 the two-year annual average total revenue requirement (before credits) is $2.8 billion (not including power purchase expenses), while total revenue credits are roughly $0.85 billion, which is split between secondary sales (includes slice value of secondary, and is decremented for balancing purchases, hedging, other committed purchases, and augmentation expenses), and other credits/DSI revenues.

Expense Driver: Power Revenue Requirement

Change in Program Expense FY 2014/15 from BP-12	**$million**	**% Change**
ENW Operations	30	2%
Bureau Operations	5	<1%
Corps Operations	25	1%
Energy Efficiency Operations	5	<1%
Fish & Wildlife	20	1%
Internal Operations	10	1%
Capital-Related Costs	25	1%
Other	10	1%
	130	7%
Secondary and Other Revenues*		
Net Secondary	95	5%
Hedging and Mitigation	(25)	-1%
Augmentation Purchases	45	3%
Other Credits	(25)	-1%
	90	5%
	220	12%

*The effect of integration of additional wind capacity in the Pacific Northwest, and any resulting negative impact on inventory of secondary energy sold is not modeled at this time. Additional installed capacity is modeled in Aurora, and included in the market price forecast which is used in the valuation of secondary energy.
Note: Net Secondary and Augmentation Purchase amounts were revised to reflect a late-breaking update to the forward gas price assumption.

Expense Driver: Initial Thoughts on Strategic Approach

- **Energy Northwest Operations and Maintenance (13 percent of Power's revenue requirement)**
  - Improve performance of plant relative to industry peers.
  - *May* see increased costs associated with new regulatory requirements as a consequence of the Fukushima disaster.

- **Fish and Wildlife Program (11 percent of Power's revenue requirement)**
  - Continue implementing the Fish Accords and established ESA obligations.

- **Corps of Engineers Operations and Maintenance (8 percent of Power's revenue requirement)**
  - The FCRPS produces power at well-below the market price of electricity.
  - System is aging – over half of the asset base is older than 50 years.
  - In some cases, investments are needed now – even those that could exceed the rate of inflation – in order to avoid future breakdowns at the powerhouses.
  - Capital program addresses this issue as well – it is important to continue the capital program in order to avoid future higher expense for unscheduled maintenance or outages.
  - It is important to understand the difference between O&M funding needed to sustain long-term value, as opposed to O&M desired to maintain status quo programs.

Expense Driver: Initial Thoughts on Strategic Approach

- **Internal Operations (6 percent of Power's revenue requirement)**
  - A wage freeze has absorbed some of the increases in this category.
- **Bureau of Reclamation Operations and Maintenance (4 percent of Power's revenue requirement)**
  - These expenditures are largely driven by the costs of non-routine extraordinary maintenance at Grand Coulee and regulatory requirements (WECC/NERC).
- **Energy Efficiency (2 percent of Power's revenue requirement)**
  - The focus is on meeting the Council's targets at the least cost possible.

Generation Inputs

Key Drivers of Variable Energy Resource Balancing Service (VERBS) Revenue Credit and VERBS Rate

- **Source of within-hour *Inc/Dec* balancing reserve inventory**
  - Limits on amount of balancing reserves that can be supplied by the Federal Columbia River Power System (FCRPS) : 900 MW *Inc* and 1100 MW *Dec*
  - For the BP-12 rate period, BPA forecast a rate period average supply of approximately 791 MW *Incs* and 1012 MW *Decs*
  - Balancing reserve acquisitions will be needed beyond these FCRPS limits.
- **Factors impacting need for within-hour *Inc/Dec* capacity**
  - Installed wind capacity, participation in Committed Intra-Hour Scheduling, Customer-Supplied Generation Imbalance, etc.
- **The revenue credit to power rates for VERBS will grow to the extent that increasing amounts of balancing reserves are supplied by the FCRPS up to the limits (900/1100 MW)**
  - For the BP-12 rate period, power rates reflect a revenue credit of $53 million per year for the cost of the FCRPS supplying balancing reserves for VERBS.
  - Based on preliminary analysis for BP-14, the FCRPS portion of the VERBS revenue credit could increase by $10 to $20 million[/1]
- **When the 900/1100 MW limits are reached, a major cost driver of the VERBS rate will be the cost of the additional *Inc/Dec* balancing reserve acquisitions**

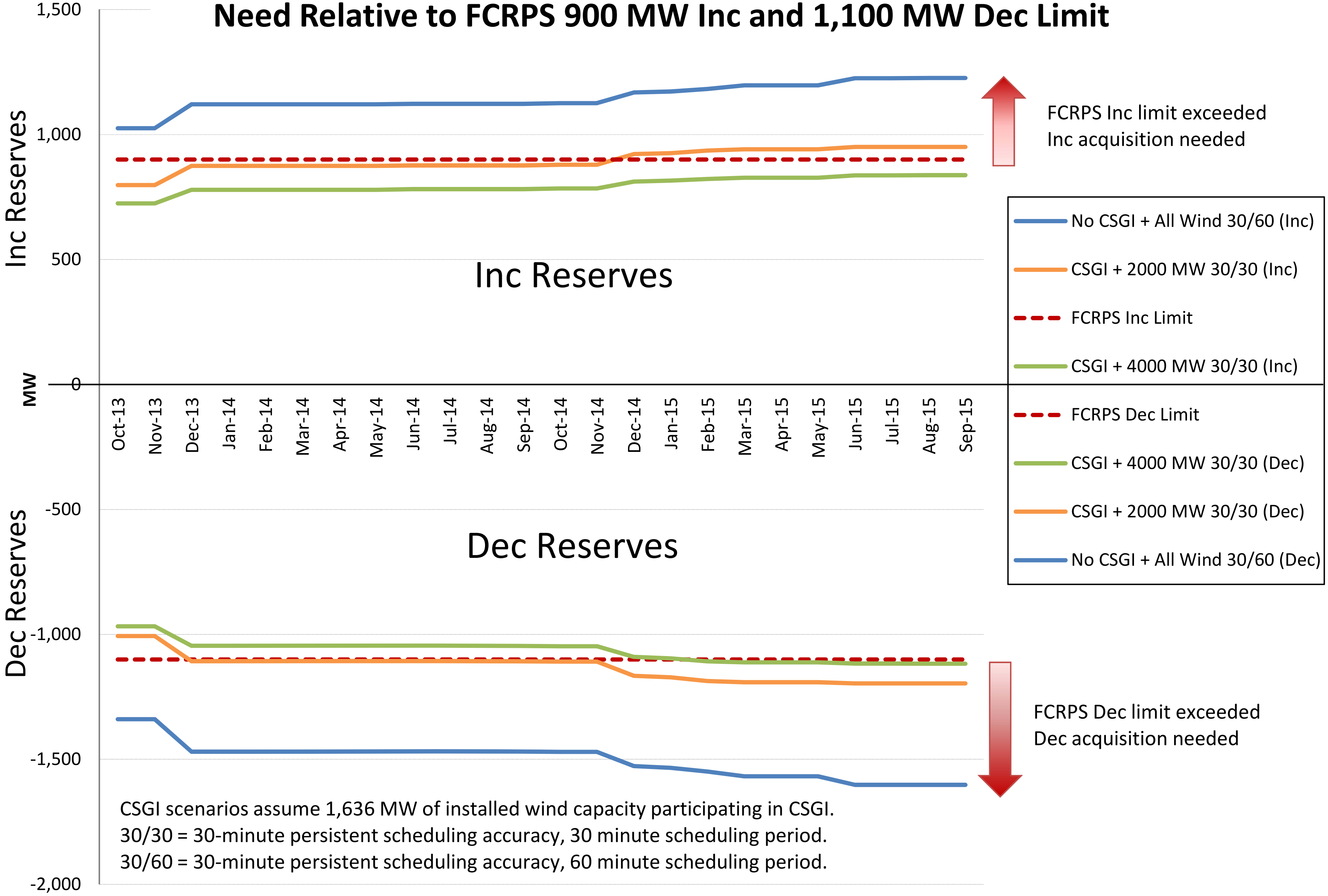
[/1] Change in embedded cost estimated with 2010 IPR values adjusted for 10% capital spending reduction. A portion of the revenue credit for VERBS replaces reductions in the net secondary revenue credit due to the use of FCRPS capacity to provide generation inputs. The estimated range in the VERBS revenue credit is the result of the timing uncertainty around when the FCRPS will reach its limit.

Preliminary Forecast of Installed Wind Capacity for FY 2014-2015 Compared to FY 2012-2013

	BP-12, FY 2012/13	BP-14, FY 2014/15
Installed Wind Capacity - Beginning of Rate Period (MW)	**3,792**	**4,912**
Installed Wind Capacity - End of Rate Period (MW)	**5,525**	**6,272**
Installed Wind Capacity - Annual Average Over Rate Period (MW)	**4,693**	**5,752**

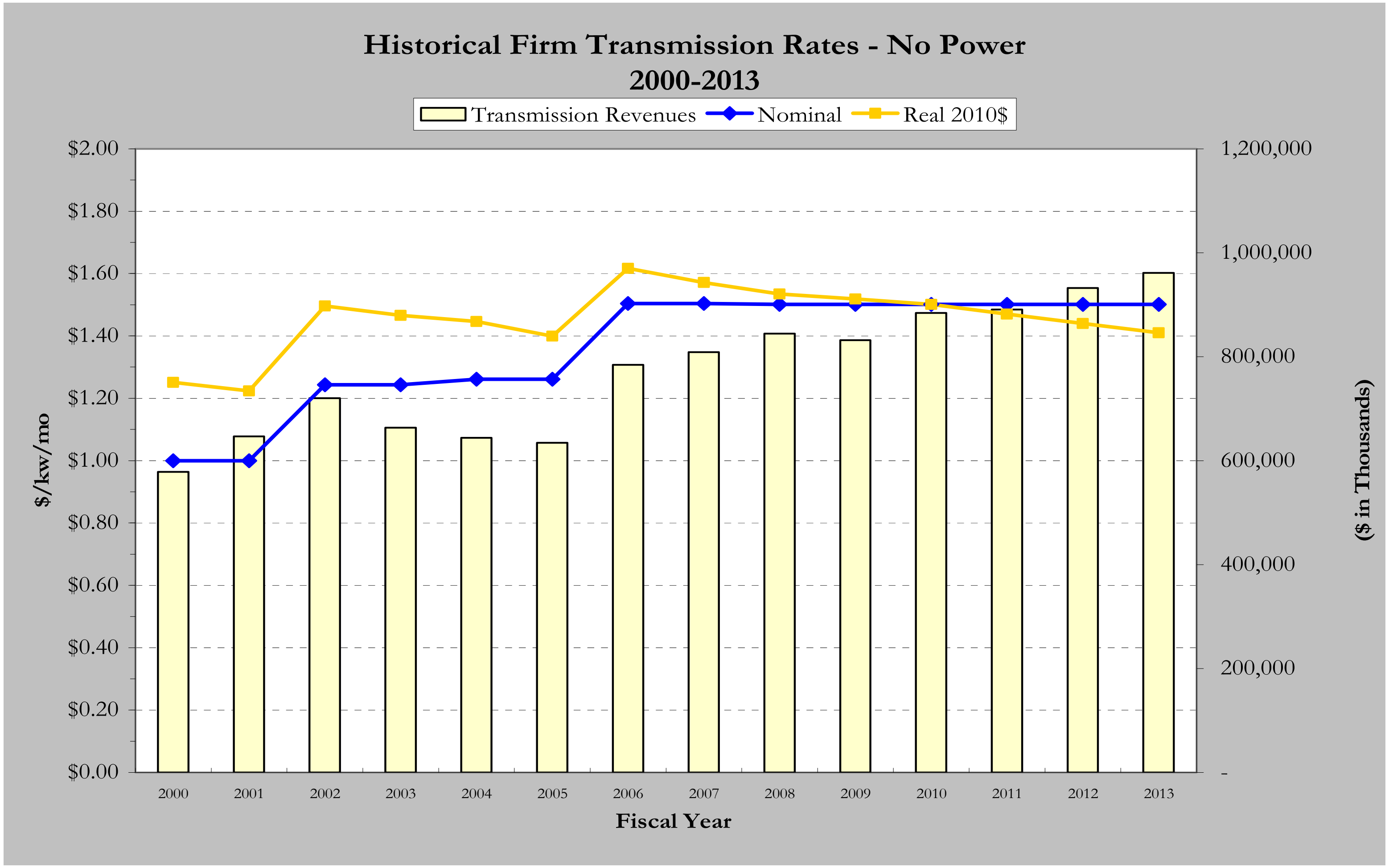
*BP-12 values are based on the rate case final studies. BP-14 values are based on a December 2011 preliminary draft estimate, which is lower than the BP-12 forecast.

Very Preliminary Forecast of Inc/Dec Within-hour Balancing Capacity Need Relative to FCRPS 900 MW Inc and 1,100 MW Dec Limit

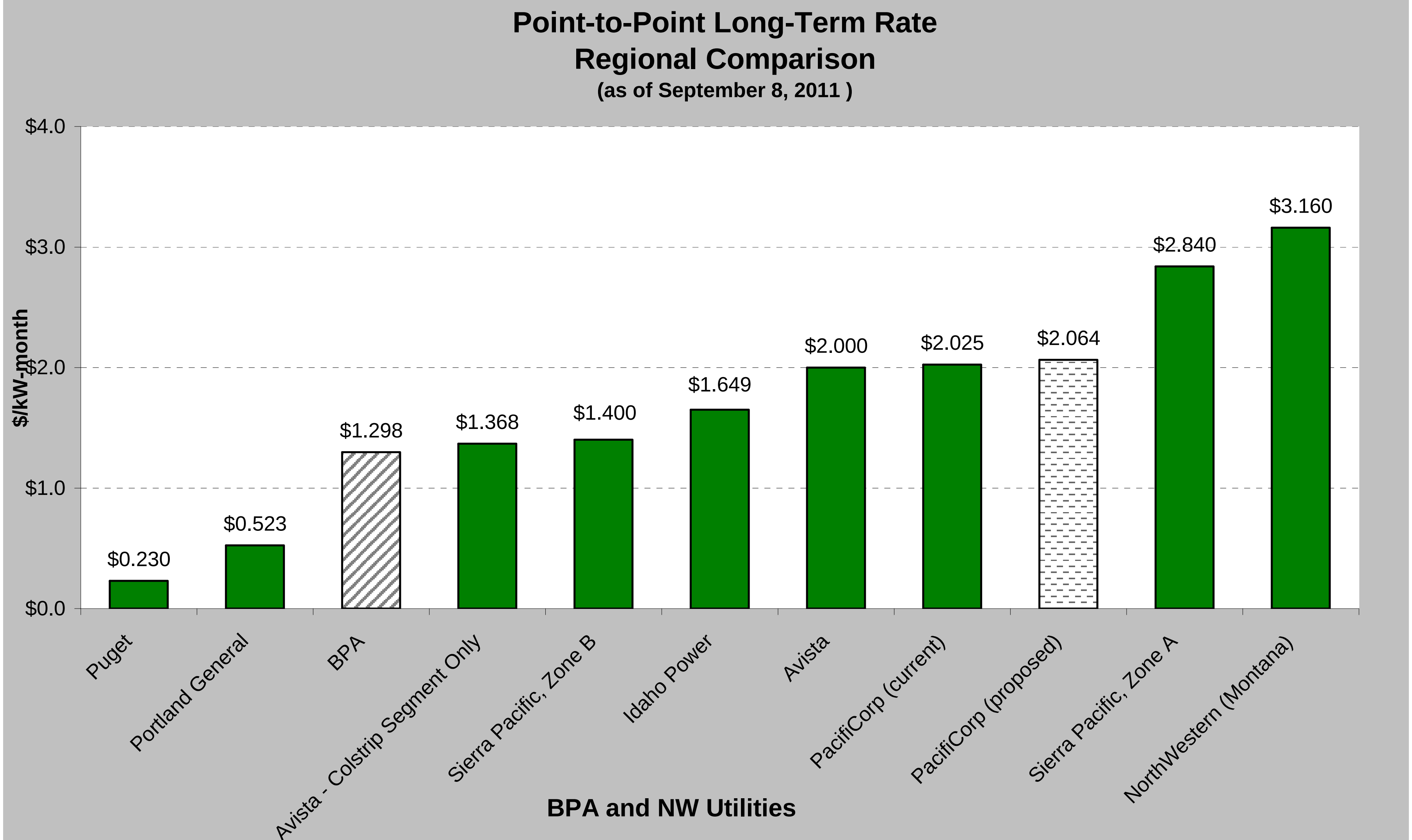


Transmission Services

Transmission Historical Rates



Transmission Services - Comparison to Other Utilities



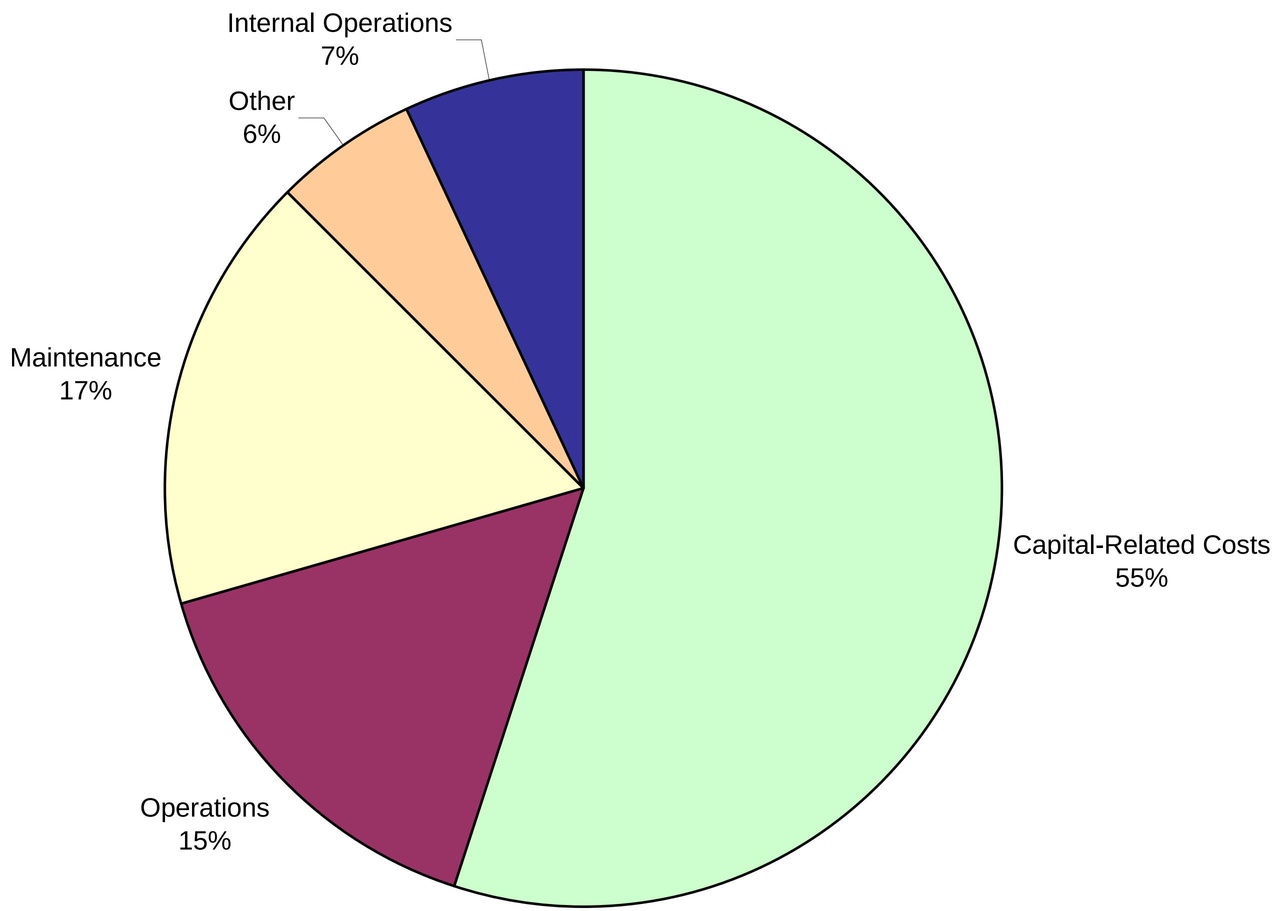
PTP rates only: Does not include required Ancillary Services

Transmission Rate Drivers

The two main drivers to the increase of Transmission rates are O&M expenses and capital related costs:

- O&M expense is increasing due to the system and reliability requirements.
- Capital related costs are increasing due to capital investment in the aging system (over 60 years old) and some additional capital investment in regional capacity needs.

Transmission Revenue Requirement Components as a % for FY 2014-15



Transmission Program Expenses
Rate Case 2012-13 to FY 2014-15:
Contribution to Overall Rate Change

Note: 2010 IPR with 10% Capital Reduction Over 10 Years

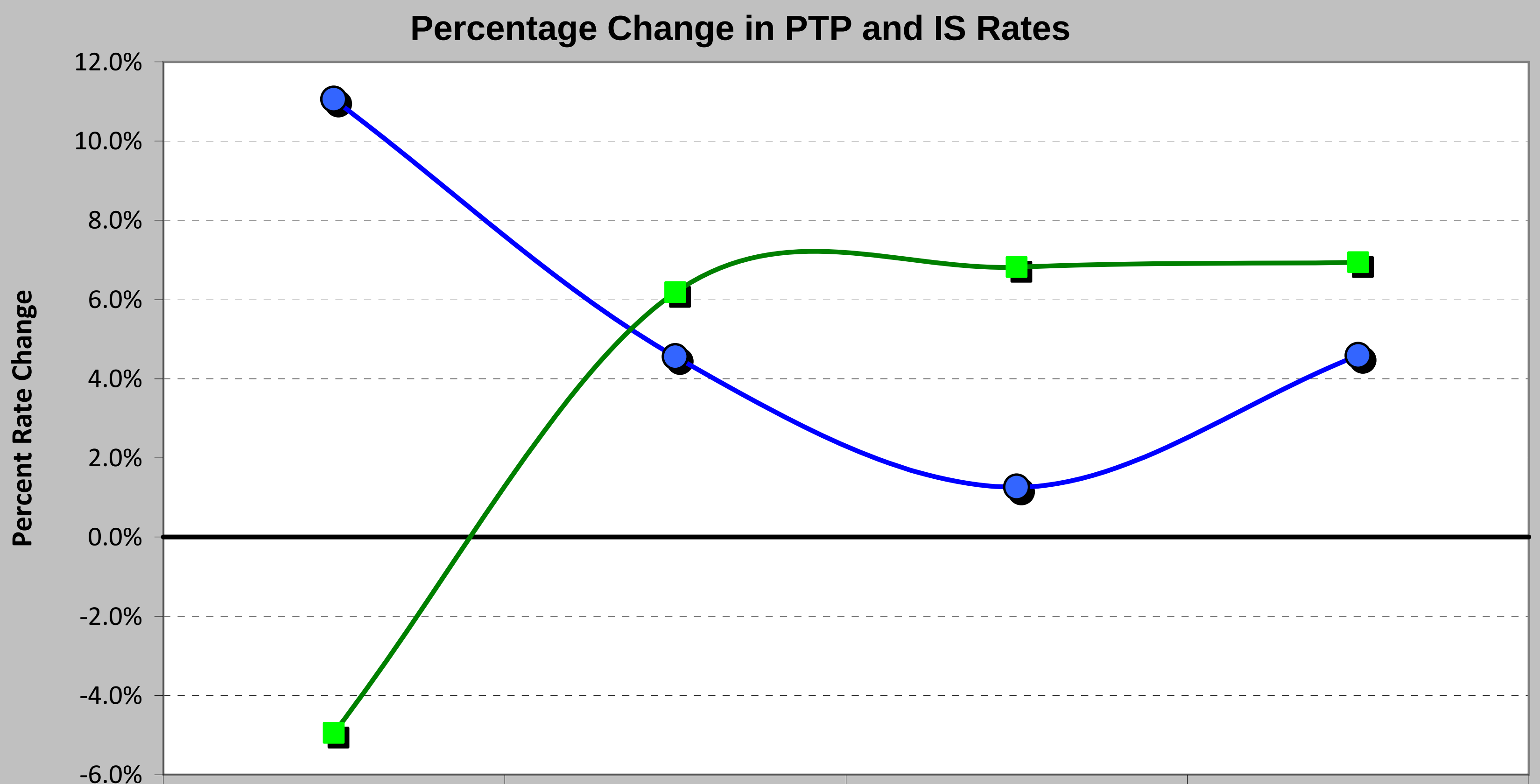
	Cost Contribution to Total Rate Change		$ in Millions	Percent
1	Operations		15	1.3%
2	Maintenance		10	0.9%
3	Other		5	0.4%
4	Internal Operations		5	0.4%
5	**Expense Sub-Total**		35	3.0%
6	**Capital-Related Costs**		70	6.0%
7	**Use of Reserves for Rate Relief** [1/]		35	3.0%
8	**Total Revenue Requirement**	$	140	12%

1/ The use of reserves were used for rate relief for FY 12-13 and the use of reserves were not assumed in FY 14-15.
2/ Compliance – ATC, CIP
3/ Expense portion of the Replacements

Transmission Highlights

- Rates for the Network may increase to 11% in the next rate period; and thereafter, have an increase that is more modest in out-year rate periods.
- Rates for the Southern Intertie may decrease for the next rate period by 5%; and thereafter, increase modestly over the following rate periods. The out-year projections for the Southern Intertie show a possible increase due to investments needed to sustain the Southern Intertie rating.
- The major driver for the rates is the capital program to sustain our investments (see capital slide).
- BPA is engaging in COSA workshops and any rate implications are not yet known.

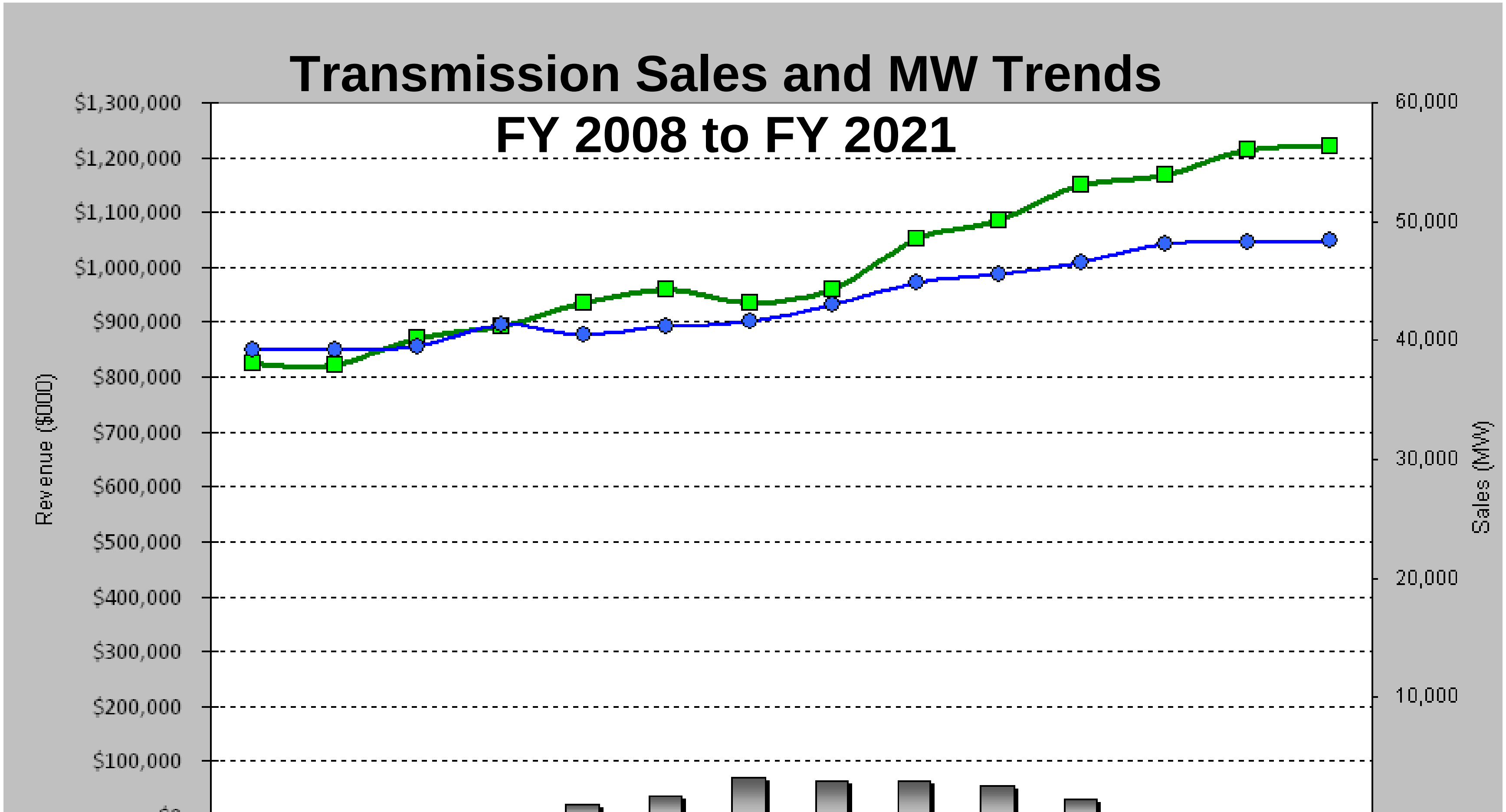
Transmission Initial Analysis of Rate Increase % FY 2014-21: IPR 2010



	FY 14-15	FY 16-17	FY 18-19	FY 20-21
PTP/NT Rate	11.1%	4.6%	1.3%	4.6%
IS Rate	-4.9%	6.2%	6.8%	6.9%

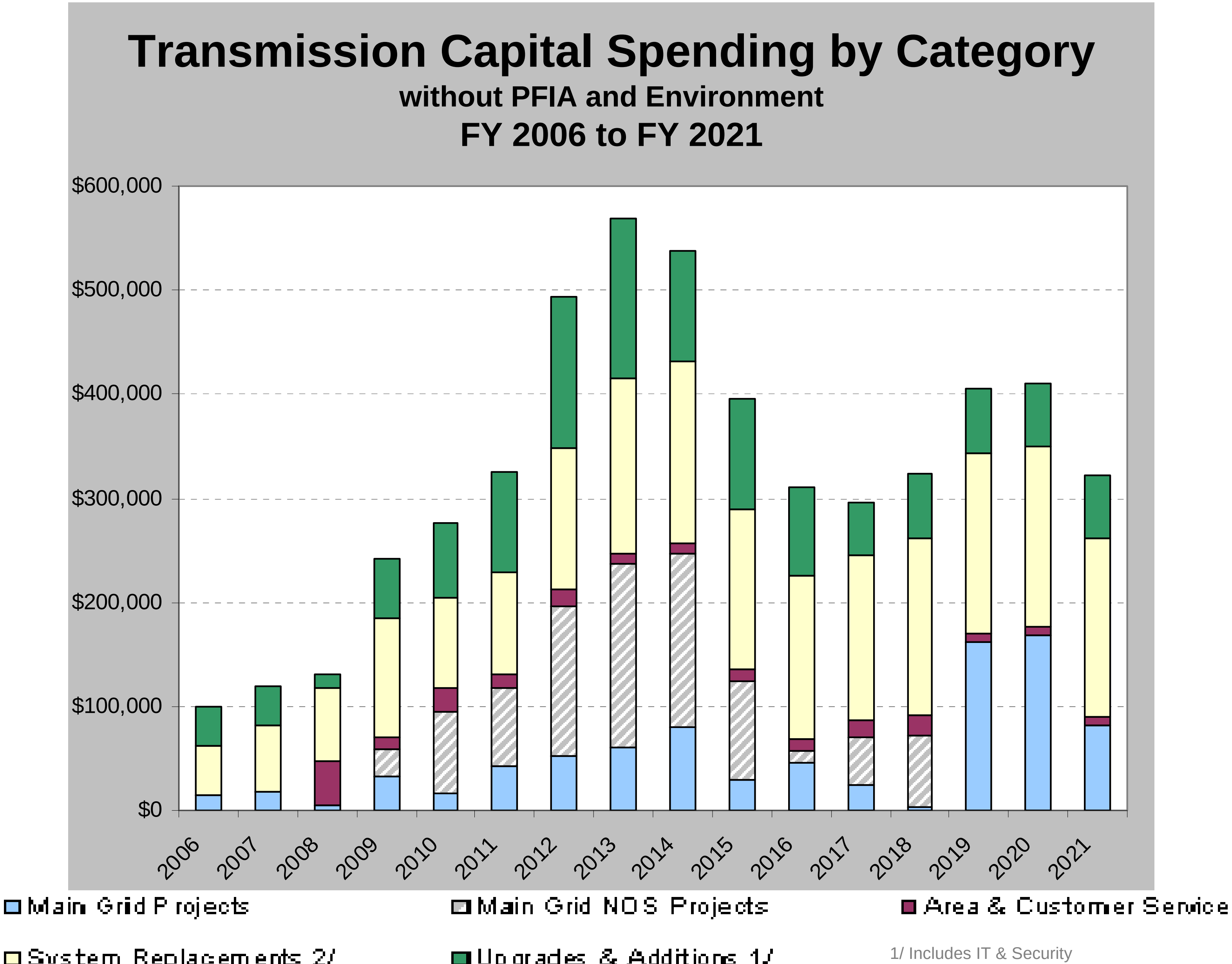
Rate Period

Assumes no PTP or NT rate design change.



	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021
Deferrals (Forecast)					1,042	1,768	3,258	3,018	3,026	2,600	1,453	50	0	0
Revenues (Actuals)	$825,591	$822,104	$869,750	$890,861	$936,384	$958,405	$936,209	$958,700	$1,052,337	$1,085,166	$1,149,755	$1,167,643	$1,213,174	$1,221,379
Sales (Actuals)	39,265	39,265	39,511	41,279	40,404	41,210	41,631	43,006	44,871	45,509	46,625	48,117	48,294	48,350

- Revenue dollars at current rates
- Assumes NOS builds and associated incremental revenues
- No assumption for Cross Cascade or B2H lost revenues
- Assumes deferrals related to PTSA
- Assumes rollovers
- Assumes no termination or defaults for PTSA0



1/ Includes IT & Security
2/ Includes Workplace Facilities Estimate

Finance

Transmission Financial Reserves

- Transmission ended FY 2011 with financial reserves of $532 million; a decrease of $74 million from the previous year. The rate case for FY 2011 planned to draw reserves down by $47 million. In 2012 and 2013 we plan to use almost $100 million to both minimize any rate impacts and fund capital investments of $30 million.
- Options for the use of financial reserves beyond what is needed to meet risk mitigation requirements include:
  - Offsetting rate increases until the reserve balance is equal to the amount needed for risk mitigation; slow or fast draw down over time.
  - Funding capital investments rather than using Treasury borrowing, contributing to long-term rate stability.

Power Financial Reserves

- Power rates could generate as much as $140 million in cash flow during the 2014-15 rate period because we expect non-cash expenses to exceed cash requirements for repayment of Treasury bonds and appropriations. Both Slice and non-Slice customers would contribute to this cash flow.
- Without any change in direction this would simply increase available financial reserves. However, since reserves are the basis for non-Slice risk mitigation, Slice customers would be contributing a share of that risk mitigation.
- A couple of options this cash flow could serve include:
  - Near-term rate reduction for all customers.
  - Funding for capital investments rather than using Treasury borrowing, contributing to long-term rate reduction.
- From what we know there will be a cash deficit in post 2024.

2014-15 Debt Service

- Actions BPA Plans to Take
  - Include DOE fuel settlement to reduce EN debt service
  - Refinance Federal and Non Federal debt for Savings
  - Tune-up debt service forecasting methodologies

- Actions BPA Plans to Explore Further
  - Revise variable rate debt and investment practices
  - Assess overall debt and investment portfolio management to minimize interest expense
  - Additional debt management opportunities such as debt restructuring actions
  - Revise funding contributions to the CGS decommissioning fund

Where We Go From Here

- **Today – Building the Framework for the 2012 IPR**
- **March-April – Capital Investment Review (CIR) Public Process**
- **June-July – 2012 Integrated Program Review (IPR) Public Process**
- **November 2012 – Power and Transmission Initial Rate Proposal for FY 2014-2015**
- **July 2013 - Power and Transmission Final Rate Proposal for FY 2014-2015**

Questions / Comments

- If you have questions pertaining to this meeting or future public processes, please contact BPAFinance@bpa.gov or your Account Executive.

Feedback

- Please take a few minutes to fill out a short survey pertaining to this meeting. https://www.surveymonkey.com/s/9P88KWM