BP-18 Transmission Rate Case Workshop

July 27, 2016

Agenda

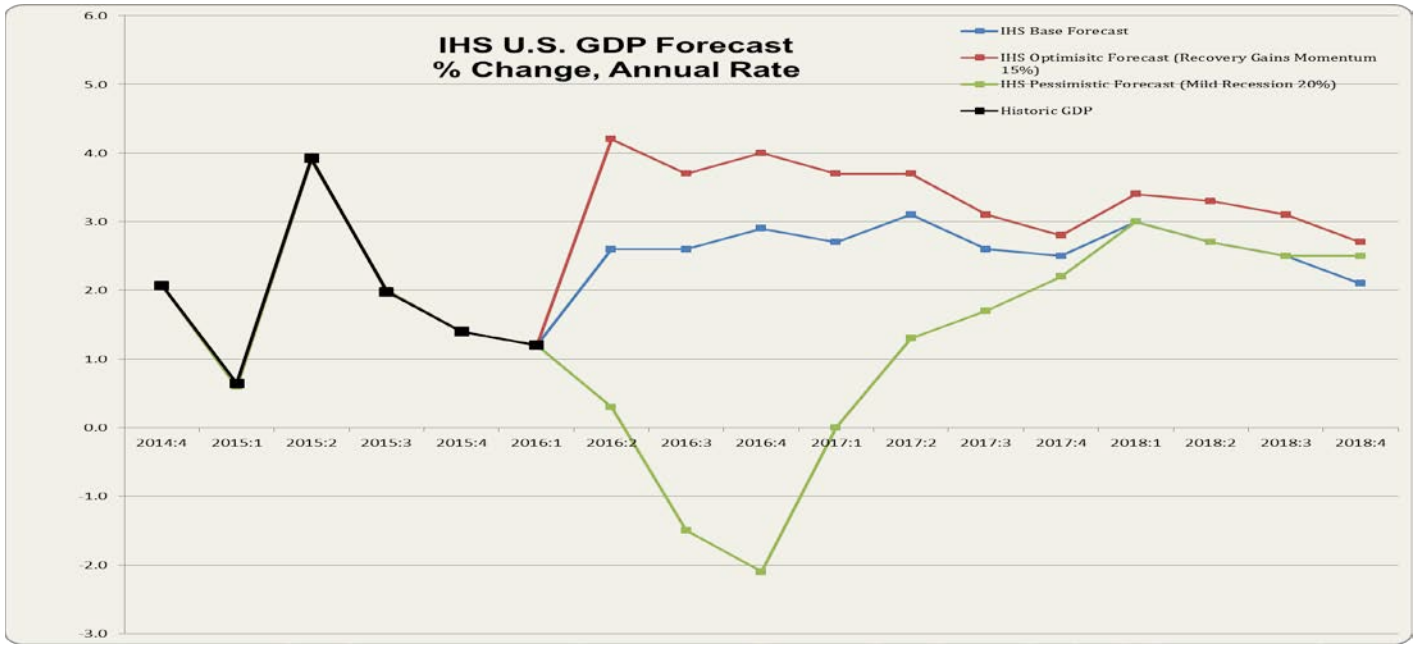
- NT Load Forecasts
- Sales Forecast
- LGIA
- Rates Model
- Proposed Rates Schedule Changes

NT Load Forecasts

NT Load Forecasts - items

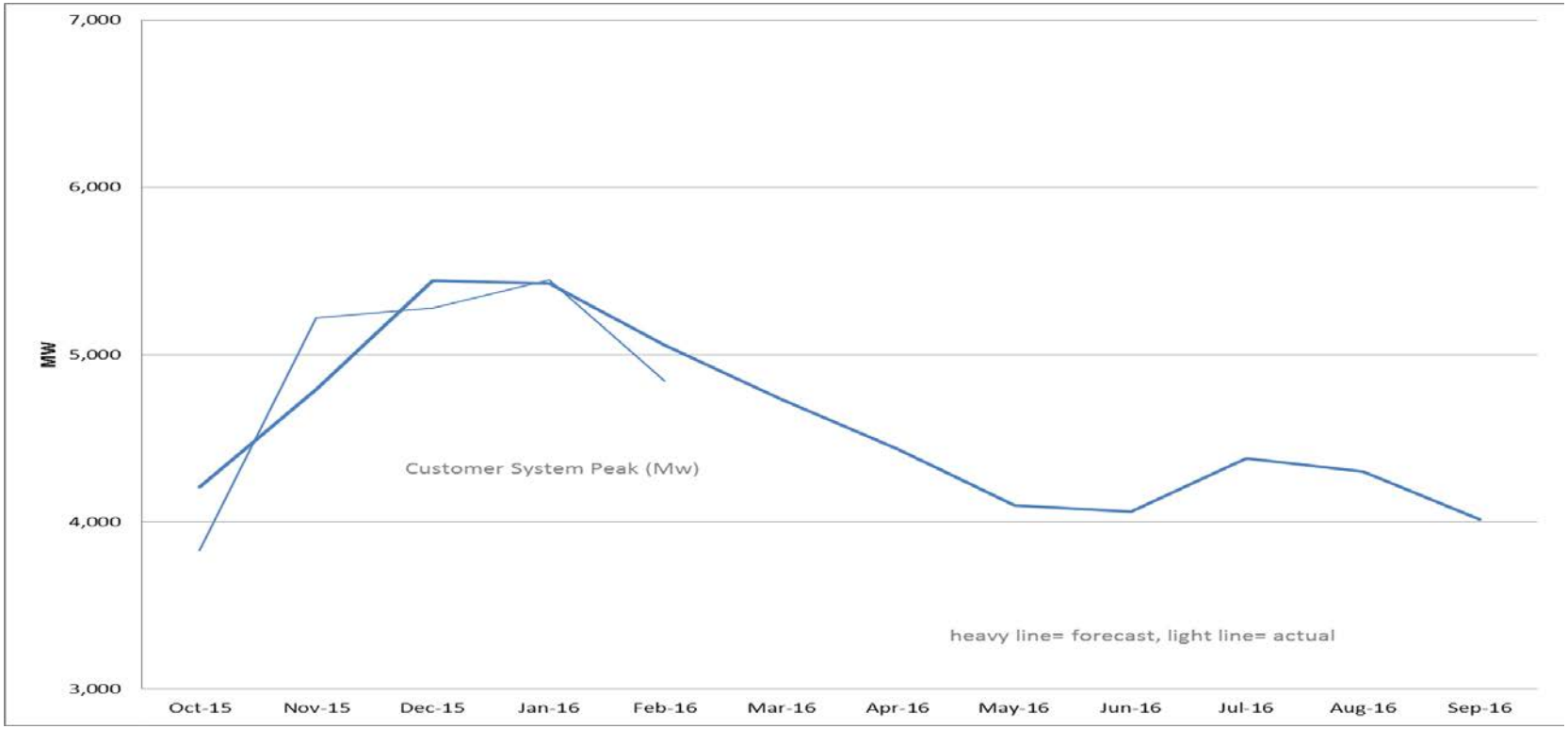
- Review economic conditions
- Review current model performance
- New forecast quantities

Forecasted Economic Conditions Continue from Last Year



- Somewhat positive GDP growth is still expected for the nation
- Regional unemployment has improved, under-employed or employee re-entry to workforce will be a drag on growth.
- Load continues with little significant growth
- World economic concerns continue
- Regular economic reports continue to indicate uncertainty as reports cycle between positive and negative updates

Current Models - Peaks



- Demand models are performing well after compensating for the ups and downs of the weather.

Forecasted Agency Loads Continue as Planned Last Year

	MWa				
	2016	2017	2018	2019	2020
Prior forecast (May 2015)	9,152	9,261	9,388	9,495	9,576
Current Forecast (Mar 2016)	8,978	9,129	9,244	9,361	9,459
change	-173	-133	-143	-134	-117
% change	-1.9%	-1.4%	-1.5%	-1.4%	-1.2%

- Downward bias in forecast adjustments
  - ~30% of the customers increased forecast over last year levels, ~70% reduced forecasts
  - Average change about 1aMW per customer
- Bulk of changes are the results of anticipated specific large customer adjustments with 80% of change coming from a few customers

Sales Forecast

Sales Forecast Assumptions

- Loads from Agency Load Forecast assumed a .7% level of load growth.
- Legacy products assumed to convert to Point-to-Point as they expire. Integration of Resources (IR) fully expires in FY 2019. Formula Power Transmission (FPT) has expirations through FY 2019.
- Network Point-to-Point (PTP LT) increase through FY 2019 from deferrals taking service and new service offers.
- There is no assumption of additional conditional firm offers in the forecast.
- There is an assumption of some generation and loads that match up with Power's assumption
- Intertie Point-to-Point (IS LT) include the sales from the PDCI upgrade.
- IS Hourly assumes rate design change to a 25 hour denominator from 80 hours. Sales reduced as a result of a rate change to $12 per MWh.

Sales Forecast

Sales in monthly average MW	FY 2017		FY 2018	FY 2019
Revenue Product	BP-16 Final	Proposed BP-18 Initial	Proposed BP-18 Initial	Proposed BP-18 Initial
Formula Power Transmission	981	909	884	839
Integration of Resources	266	266	244	0
Network Integration	6,392	6,299	6,330	6,388
Point-to-Point Long Term	26,620	25,759	26,485	27,218
Point-to-Point Short Term	949	1,127	1,083	1,058
Montana Intertie Long Term	16	16	16	16
Southern Intertie Long Term	6,012	6,000	6,042	6,042
Southern Intertie Short Term	204	103	52	51
Utility Delivery	160	166	164	164

Proposed BP-18 Initial Proposal Revenue Credits

REVENUE PRODUCT CATEGORY	FY 2017	FY 2018	FY 2019
FIBER - OTHER REIMBURSABLE REV	906,565	906,565	906,565
FIBER- OTHER REVENUE	8,429,156	8,429,156	8,429,156
WIRELESS/PCS - OTHER REVENUE	5,201,304	5,201,304	5,201,304
WIRELESS/PCS - REIMBURSABLE	4,032,000	4,032,000	4,032,000
AC-PNW PSW INTERTIE	1,774,800	1,774,800	1,774,800
DSI DELIVERY	1,914,696	1,914,696	1,914,696
LAND LEASES AND SALES	295,303	295,303	295,303
MISC SERVICES-LOSS-EXCH-AIR	42,912	42,912	42,912
NFP - DEPR PNW PSW INTERTIE	3,377,772	3,377,772	3,377,772
OPERATIONS & MAINTENANCE	869,864	869,864	869,864
OTHER MISC LEASES	104,859	104,859	104,859
OTHER REVENUE SOURCES	149,136	149,136	149,136
REMEDIAL ACTION SCHEME	26,916	26,916	26,916
RESERVATION FEES	1,196,150	893,400	670,050
TOWNSEND-GARRISON TRANS	12,420,708	12,420,708	12,420,708
TRANSMISSION SHARE OF IPP	245,697	245,697	245,697
USE OF FACILITIES	5,061,912	5,061,912	5,061,912

Proposed BP-18 Initial for FY 2017

FY 2017 (MW)	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	AVG
FPT	917	917	917	917	917	917	917	917	917	884	884	884	**909**
IR	266	266	266	266	266	266	266	266	266	266	266	266	**266**
PTP	25,652	25,652	25,652	26,570	26,570	26,611	26,611	26,711	26,711	26,743	26,843	26,846	**26,431**
PTP SDD	-672	-672	-672	-672	-672	-672	-672	-672	-672	-672	-672	-672	**-672**
PTP Total	**24,980**	**24,980**	**24,980**	**25,898**	**25,898**	**25,939**	**25,939**	**26,039**	**26,039**	**26,071**	**26,171**	**26,174**	**25,759**
IS	5,872	5,872	5,872	6,042	6,042	6,042	6,042	6,042	6,042	6,042	6,042	6,042	**6,000**
IM	16	16	16	16	16	16	16	16	16	16	16	16	**16**
NT, cp	5,753	6,943	7,939	7,515	7,259	6,472	5,845	5,421	5,755	6,248	6,227	5,640	**6,418**
NT SDD	-120	-118	-118	-118	-118	-118	-120	-120	-120	-120	-120	-120	**-119**
NT, cp Total	**5,633**	**6,825**	**7,821**	**7,397**	**7,141**	**6,354**	**5,725**	**5,301**	**5,635**	**6,128**	**6,107**	**5,520**	**6,299**
NT, ncp	6,878	7,919	8,864	8,822	8,400	7,702	7,304	6,584	6,490	6,930	6,816	6,424	**7,428**
NT, SDD	-120	-118	-118	-118	-118	-118	-120	-120	-120	-120	-120	-120	**-119**
NT, ncp Total	**6,758**	**7,801**	**8,745**	**8,704**	**8,282**	**7,584**	**7,185**	**6,464**	**6,370**	**6,810**	**6,697**	**6,304**	**7,309**
PTP ST Block 1	7	43	133	202	206	370	509	620	689	71	42	8	**242**
PTP ST Block 2	73	175	288	372	417	785	1,626	1,543	875	347	171	55	**561**
PTP ST Hourly	149	232	290	304	278	379	425	537	531	413	186	177	**325**
PTP ST Total	**228**	**450**	**711**	**878**	**901**	**1,533**	**2,560**	**2,699**	**2,096**	**832**	**399**	**241**	**1,127**
IS ST Block 1	0	0	7	12	17	12	0	0	10	5	0	0	**5**
IS ST Block 2	0	0	8	15	21	15	0	0	13	6	0	0	**6**
IS ST Hourly	97	90	70	96	85	75	94	111	145	99	57	76	**91**
IS ST Total	**97**	**90**	**84**	**123**	**123**	**101**	**94**	**111**	**168**	**111**	**57**	**76**	**103**

Proposed BP-18 Initial for FY 2018

FY 2018 (MW)	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	AVG
FPT	884	884	884	884	884	884	884	884	884	884	884	884	**884**
IR	266	266	266	266	266	266	266	266	266	266	266	0	**244**
PTP	27,003	27,003	27,012	27,012	27,012	27,012	27,012	27,112	27,262	27,262	27,462	27,723	**27,157**
PTP SDD	-672	-672	-672	-672	-672	-672	-672	-672	-672	-672	-672	-672	**-672**
PTP Total	**26,331**	**26,331**	**26,340**	**26,340**	**26,340**	**26,340**	**26,340**	**26,440**	**26,590**	**26,590**	**26,790**	**27,051**	**26,485**
IS	6,042	6,042	6,042	6,042	6,042	6,042	6,042	6,042	6,042	6,042	6,042	6,042	**6,042**
IM	16	16	16	16	16	16	16	16	16	16	16	16	**16**
NT, cp	5,752	6,915	7,932	7,534	7,307	6,515	5,885	5,463	5,803	6,309	6,286	5,690	**6,449**
NT SDD	-120	-118	-118	-118	-118	-118	-120	-120	-120	-120	-120	-120	**-119**
NT, cp Total	**5,632**	**6,797**	**7,813**	**7,415**	**7,189**	**6,397**	**5,765**	**5,343**	**5,683**	**6,189**	**6,166**	**5,570**	**6,330**
NT, ncp	6,911	7,948	8,880	8,851	8,467	7,754	7,338	6,623	6,526	6,997	6,898	6,502	**7,475**
NT, SDD	-120	-118	-118	-118	-118	-118	-120	-120	-120	-120	-120	-120	**-119**
NT, ncp Total	**6,791**	**7,830**	**8,762**	**8,733**	**8,348**	**7,636**	**7,219**	**6,503**	**6,406**	**6,877**	**6,778**	**6,382**	**7,356**
PTP ST Block 1	7	43	130	196	205	379	496	592	605	74	44	8	**232**
PTP ST Block 2	76	171	281	354	415	804	1,591	1,500	781	353	178	56	**546**
PTP ST Hourly	153	221	277	275	276	407	366	456	423	427	194	180	**305**
PTP ST Total	**236**	**434**	**687**	**825**	**895**	**1,590**	**2,453**	**2,548**	**1,809**	**854**	**415**	**245**	**1,083**
IS ST Block 1	0	0	7	12	17	12	0	0	10	5	0	0	**5**
IS ST Block 2	0	0	8	15	21	15	0	0	13	6	0	0	**6**
IS ST Hourly	36	36	38	37	41	45	39	42	48	46	37	37	**40**
IS ST Total	**36**	**36**	**53**	**64**	**79**	**72**	**39**	**42**	**71**	**57**	**37**	**37**	**52**

Proposed BP-18 Initial for FY 2019

FY 2019 (MW)	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	AVG
FPT	884	884	884	834	834	834	834	834	834	802	802	802	**839**
IR	0	0	0	0	0	0	0	0	0	0	0	0	**0**
PTP	27,828	27,828	27,828	27,878	27,878	27,878	27,878	27,878	27,878	27,910	28,010	28,020	**27,891**
PTP SDD	-672	-672	-672	-672	-672	-672	-672	-672	-672	-672	-676	-676	**-673**
PTP Total	**27,156**	**27,156**	**27,156**	**27,206**	**27,206**	**27,206**	**27,206**	**27,206**	**27,206**	**27,238**	**27,334**	**27,344**	**27,218**
IS	6,042	6,042	6,042	6,042	6,042	6,042	6,042	6,042	6,042	6,042	6,042	6,042	**6,042**
IM	16	16	16	16	16	16	16	16	16	16	16	16	**16**
NT, cp	5,841	7,015	8,034	7,580	7,346	6,558	5,912	5,497	5,858	6,372	6,338	5,737	**6,507**
NT SDD	-120	-118	-118	-118	-118	-118	-120	-120	-120	-120	-120	-120	**-119**
NT, cp Total	**5,722**	**6,897**	**7,916**	**7,462**	**7,227**	**6,439**	**5,792**	**5,377**	**5,739**	**6,253**	**6,218**	**5,617**	**6,388**
NT, ncp	7,030	8,076	9,006	8,890	8,510	7,783	7,374	6,673	6,588	7,043	6,944	6,537	**7,538**
NT, SDD	-120	-118	-118	-118	-118	-118	-120	-120	-120	-120	-120	-120	**-119**
NT, ncp Total	**6,910**	**7,958**	**8,888**	**8,772**	**8,392**	**7,665**	**7,254**	**6,553**	**6,468**	**6,923**	**6,825**	**6,417**	**7,419**
PTP ST Block 1	8	43	131	194	203	373	489	577	574	74	44	9	**227**
PTP ST Block 2	83	175	284	347	405	791	1,570	1,475	746	355	178	61	**539**
PTP ST Hourly	163	231	283	265	263	388	330	413	384	432	194	164	**293**
PTP ST Total	**253**	**449**	**699**	**806**	**871**	**1,552**	**2,389**	**2,465**	**1,703**	**861**	**416**	**235**	**1,058**
IS ST Block 1	0	0	7	12	17	12	0	0	10	5	0	0	**5**
IS ST Block 2	0	0	8	15	21	15	0	0	13	6	0	0	**6**
IS ST Hourly	39	36	39	36	40	42	38	41	44	47	37	37	**40**
IS ST Total	**39**	**36**	**53**	**63**	**78**	**68**	**38**	**41**	**67**	**58**	**37**	**37**	**51**

LGIA

LGIA Background

- LGIA (and COI) deposits are considered advanced payment of future revenues. The deposited funds are used for construction of assets. These funds earn interest from the first day of deposit until the advance is fully repaid. The LGIA customer receives a transmission credit on their bill until the deposit is repaid.

- The revenue requirement effect of LGIA is equal to the total annual revenue credit. The effect appears in three places in the revenue requirement. The sum of all three, the net effect on the revenue requirement, is equal to the total credit.

Revenue Requirement Effect of LGIA =

(1) Interest accrued on outstanding deposit balances
(2) Depreciation on the LGIA assets
(3) Minimum Required Net Revenues (MRNR = revenue credit minus #1 & #2)

- The LGIA transmission credits are repaid in a much shorter timeframe than the useful life of the assets. Credits tend to be repaid in 8-12 years while the assets may have much longer service lives.

Non-Cash Revenues: Effect on Revenue Requirements

- To achieve cost recovery, which is demonstrated on a cash basis, the Revenue Requirement is normally the sum of all of cash requirements
- A basic premise for setting rates is that Revenues from Proposed Rates must be greater than or equal to the Revenue Requirement
- However, if there will be non-cash (accrual) revenues in the revenue forecast, then the Revenues from Proposed Rates must be greater than the Cash Requirements to demonstrate cost recovery
- To capture this in determining the Revenue Requirement, then, the Revenue Requirement is the sum of all Cash Requirements and Non-Cash Revenues
- In the context of rate setting, then, LGIA credits function more like a cost than a revenue:
  - LGIA credits are based on rates that must recover in full the projected rate period costs
  - Until the LGIA credits are exhausted, interconnection customers do not contribute cash revenues and therefore do not contribute to the recovery of rate period costs
  - Consequentially, the remaining customers have to make up the difference

Transmission Credits Overview

- Customers who have advanced for the construction of Network Upgrades necessary to enable generation interconnection are eligible to recover their funds through two methods. (See Transmission Credits Business Practice – Version 8 for more details)
  - **Method 1:** Application of transmission credits against eligible transmission bills.
    - PTP Service: Transmission credits applied in a given month is based on the amount of transmission capacity reserved at the generator.
    - NT Service: Transmission credit applied in a given month is based on a ratio of the customer's maximum hourly scheduled energy from a generating resource to their maximum Network load set on the hour of the transmission peak over the last 12 months.
  - **Method 2:** Cash payment based on the Generating Facility Capacity, multiplied by an average plant capacity factor, multiplied by the current PTP Long-Term rate.

- Customers earn interest on funds advanced for Network Upgrades. Interest is accrued quarterly from the date of deposit.
  - LGIAs signed prior to July 15, 2009, the FERC rate is applied or a fixed interest rate is specified in the contract.
  - LGIAs signed on or after July 15, 2009, the interest rate is the USD Government Agency BVAL Curve (identified by Bloomberg BVAL curve "BS131".

Transmission Credits Rate Case Process

- The Generation Interconnection (GI) Queue was assessed to determine which generation projects were likely to be completed prior to or during the rate period.
- To the extent possible, each GI project was tied to requests in the Transmission Queue to forecast sales eligible to receive Transmission Credits.
  - When a request in the GI Queue could not be tied to requests in the Transmission Queue, a percentage of the nameplate was used to forecast the sales eligible to receive credits.
    - 30% - Year 1
    - 50% - Year 2
    - 70% - Year 3
- Projects begin receiving Transmission Credits on the later of the forecasted commercial operation date on their TSR start date (if applicable).
- The dollar value of the Transmission Credits is forecasted based upon TSRs or historical transmission credit average and the LT PTP rate.
- Interest expense was calculated based on the applicable interest rate and existing/forecasted cash deposits for Network Upgrades.

BP-18 Transmission Credit Forecast Results

- BPA currently holds $140 million in funds advanced for Network Upgrades that are currently receiving Transmission Credits. BPA holds an additional $5 million in funds advanced for Network Upgrades for projects that have not begun receiving Transmission Credits.
- For the BP-18 rate period, BPA is forecasting approximately $23 million in additional funds advanced for Network Upgrades for continuing and future interconnection projects.
- The average interest expense is $4 million per year in FY 18-19.
- The average transmission credit is $16 million per year in FY 18-19.

BP-18 Transmission Credit and Interest Forecast

The following charts show credit and interest forecasts for GI projects in two different groups:

1. Projects where customers are currently receiving Transmission Credits (rows 1-23)
2. Projects where the credit repayment forecast is based on TSRs or Generator Nameplate (rows 24-32)
3. Some projects in forecast only receive interest during rate period.

BP-18 Transmission Credit and Interest Forecast

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(I)	(J)
	Requests Currently Taking Credits	Tx Credit Balance as of 6/1/2016	Upgrade Deposits During FY17 - FY19	Forecasted Transmission Credits ($000)			Forecasted Interest ($000)		
				FY17	FY18	FY19	FY17	FY18	FY19
1	GI Request 1	$ 7,040	$ -	$ 3,867	$ -	$ -	$ 16	$ -	$ -
2	GI Request 2	$ 2,080	$ -	$ 1,108	$ 792	$ -	$ 64	$ 15	$ -
3	GI Request 3	$ 13,254	$ -	$ 674	$ 674	$ 674	$ 486	$ 479	$ 471
4	GI Request 4	$ 4,844	$ -	$ 893	$ 893	$ 893	$ 163	$ 135	$ 105
5	GI Request 5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	GI Request 6	$ 1,246	$ -	$ 845	$ -	$ -	$ 9	$ -	$ -
7	GI Request 7	$ 4,468	$ -	$ 990	$ 990	$ 990	$ 196	$ 182	$ 136
8	GI Request 8	$ 72,382	$ -	$ 6,071	$ 6,071	$ 6,071	$ 2,466	$ 2,336	$ 2,201
9	GI Request 9	$ 19,740	$ -	$ 4,771	$ 4,771	$ 4,771	$ 584	$ 432	$ 275
10	GI Request 10	$ 898	$ -	$ 650	$ 113	$ -	$ 21	$ 0	$ -
11	GI Request 11	$ 898	$ -	$ 650	$ 113	$ -	$ 21	$ 0	$ -
12	GI Request 12	$ 69	$ -	$ 50	$ 9	$ -	$ 2	$ 0	$ -
13	GI Request 13	$ 1,588	$ -	$ 1,151	$ 200	$ -	$ 36	$ 0	$ -
14	GI Request 14	$ 70	$ -	$ 44	$ 18	$ -	$ 40	$ -	$ -
15	GI Request 15	$ 1,168	$ -	$ 731	$ 296	$ -	$ 40	$ -	$ -
16	GI Request 16	$ 1,168	$ -	$ 731	$ 296	$ -	$ 22	$ 1	$ -
17	GI Request 17	$ 350	$ -	$ 219	$ 89	$ -	$ 56	$ 4	$ -
18	GI Request 18	$ 280	$ -	$ 175	$ 71	$ -	$ 42	$ 3	$ -
19	GI Request 19	$ 904	$ -	$ 570	$ 223	$ -	$ 2	$ 0	$ -
20	GI Request 20	$ 2,317	$ -	$ 1,462	$ 573	$ -	$ 28	$ 2	$ -
21	GI Request 21	$ 1,714	$ -	$ 1,082	$ 424	$ -	$ 28	$ 2	$ -
22	GI Request 22	$ 1,967	$ -	$ 1,462	$ 199	$ -	$ 9	$ 1	$ -
23	GI Request 23	$ 1,967	$ -	$ 1,462	$ 199	$ -	$ 7	$ 0	$ -

BP-18 Transmission Credit and Interest Forecast

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(I)	(J)
	Requests Currently Taking Credits	Tx Credit Balance as of 6/1/2016	Upgrade Deposits During FY17 - FY19	Forecasted Transmission Credits ($000)			Forecasted Interest ($000)		
				FY17	FY18	FY19	FY17	FY18	FY19
24	GI Request 25	$ -	$ 5,950	$ -	$ 179	$ 1,191	$ 98	$ 171	$ 155
25	GI Request 26	$ 52	$ -	$ -	$ -	$ -	$ 2	$ 2	$ 2
26	GI Request 27	$ -	$ 17,333	$ -	$ -	$ 89	$ 51	$ 348	$ 503
27	GI Request 28	$ 1,108	$ -	$ -	$ -	$ -	$ 39	$ 40	$ 41
28	GI Request 29	$ 1,287	$ -	$ 112	$ 268	$ 268	$ 51	$ 43	$ 35
29	GI Request 30	$ 659	$ -	$ -	$ -	$ -	$ 35	$ 43	$ 48
30	GI Request 31	$ 1,680	$ -	$ -	$ -	$ -	$ 89	$ 110	$ 121
31	GI Request 32	$ 50	$ -	$ -	$ -	$ -	$ 3	$ 3	$ 4
32	GI Request 33	$ 663	$ -	$ -	$ -	$ -	$ 35	$ 44	$ 48

Tx Credit Balance as of 6/1/2016	Network Upgrade Deposits Furing FY17 - FY19 ($000)
$ 145,909	$ 23,283

	FY17	FY18	FY19
Credits ($000)	$ 29,772	$ 17,461	$ 14,947
Interest ($000)	$ 4,738	$ 4,397	$ 4,146

Pre-decisional. For discussion purposes only.

Rates Model

BP-18 Rates Model: Assumptions

- We used the same methodologies used in BP-16 for all rates, except for the Hourly rates on the Southern Intertie rate design changes.
- For this workshop, we used the BP-16 Final Proposal numbers to illustrate the rate design changes in the rates model due to the Southern Intertie Hourly rate design change.
  - This version is posted to the BP-18 Meetings and Workshops page for customers to review.

BP-18 Rates Model Changes

- The BP-18 rates model was updated to reflect the rate design change for the Hourly rates on the Southern Intertie.
  - We changed the denominator from 16 hours to 5 hours (as seen on the next slide).
  - There was no change to the SCD denominator (as seen on the next slide).
- There are no other rate design changes proposed at this time.

Table 8
Calculation of Intertie Rates

	(A)	(B)	(C)	(D)	(E)
	FY 2018/2019	**Source**	**Costs**	**Sales**	**Rates**
1	**Intertie Costs**		$000/Yr	aMW	
2	Rate Development Costs	Table 3, line 33 (D)	**93,085**		
3	**Southern Intertie Sales**				
4	Long-term agreements	Table 4, line 66 (O)		5,976	
5	Short-term daily block 1	Table 5, line 42 (O)		57	
6	Short-term daily block 2	Table 5, line 43 (O)		49	
7	Hourly	Table 5, line 44 (O)		95	
8	**Sales used for cost allocation**				
9	Long-term agreements	Line 4		5,976	
10	Daily block 1 (day 1 through 5)	Line 5 x (7/5)		80	
11	Daily block 2 (day 6 and beyond)	Line 6		49	
12	Hourly	Line 7 x (7/5) x (24/5)		641	
13	Total cost allocation sales	Sum of lines 9 through 12		**6,746**	
14	**IS rate calculation**				
15	Annual ($/kW-yr)	Line 2 / line 13			13.80
16	Monthly ($/kW-mo)	Line 15 / (12)			**1.150**
17	Daily block1 ($/kW-day)	Line 15 / (365) x (7/5)			**0.053**
18	Daily block2 ($/kW-day)	Line 15 / (365)			**0.038**
19	Hourly (mills/kWh)	Line 15 / (8.772) x (7/5) x (24/5)			**10.57**

Table 10.1
Calculation of Ancillary Service Rates

	(A) FY 2018/2019	(B) Source	(C) FY16	(D) FY17	(E) FY16/17	(F) Sales	(G) Percentage	(H) Rates	(I) Units
			$000/Yr	$000/Yr	$000/Yr	(MW)			
1	**Scheduling, System Control & Dispatch**								
2	Direct O&M	Rev Rqmt	68,057	68,953	68,505				
3	Overheads	Rev Rqmt	57,791	59,843	58,817				
4	Total O&M		125,848	128,796	127,322				
5	Depreciation	Rev Rqmt	28,124	31,617	29,870				
6	Financing costs	Rev Rqmt	4,432	5,155	4,793				
7	Planned net revenue	Rev Rqmt	2,640	2,811	2,726				
8	Total segmented SCD		161,043	168,380	**164,711**				
9	Revenue Credits	Table 3, lines 3 (H) & 14 (H)	-2,662	-2,656	-2,659				
10	WECC Costs	Table 3, lines 4 (H) & 15 (H)	-2,326	-2,363	-2,345				
11	Peak Costs	Table 3, lines 5 (H) & 16 (H)	-2,697	-2,741	-2,719				
12	Eastern Intertie Adjustment	Table 3, lines 9 (H) & 20 (H)	-24	-32	-28				
13	Industry Delivery Adjustment	Table 3, lines 10 (H) & 21 (H)	-34	-38	-36				
14	Subtotal SCD Costs	Sum of lines 8 through 13	153,299	160,549	**156,924**				
15	FPT revenue for SCD	Table 6, line 40 (D)			3,231				
16	Net SCD Costs	Line 14 - line 15			**153,693**				
17	**Sales Used for Cost Allocation**								
18	IR contract demand	Table 4, line 43 (O)				266			
19	PTP contract demand w/o SDD	Table 4, line 45 (O)				26,968			
20	Network Load Service	Table 4, line 52 (O)				7,530			
21	Southern Intertie	Table 4, line 66 (O)				5,976			
22	Montana Intertie	Table 4, line 72 (O)				16			
23	Network Short-term	Table 7, line 22 & line 23 & line 24				1,448			
24	Intertie Daily (Blocks 1 & 2)	Table 8, line 10 & line 11				129			
25	Intertie Hourly	Table 8, line 7 * 7/5 * 24/16				200			
26	Total Sales, SCD	Sum of lines 18 through 25				**42,533**			

BP-18 Rates Model: Next steps

- We will include in the rates model the BP-18 revenue requirements and sales information and share it with customers by the end of September.

Proposed Transmission Rate Schedule Changes

Proposed Rate Schedule Changes

- A draft redline version of the proposed BP-18 Transmission Rates Schedule changes is posted on the BP-18 Meetings and Workshops page.
  - Southern Intertie Hourly Non-Firm S>N Discount

Next Steps

- Next BP-18 Transmission Workshop is Wednesday, August 10
- By Wednesday, August 17:
  - Please review the draft BP-18 Transmission Rates Model and provide feedback
  - Please send any proposed language or comments on the BP-18 Transmission Rate Schedules
- Please submit comments to techforum@bpa.gov with the subject line “BP-18 Transmission Rates Model Comments” or “BP-18 Transmission Rate Schedules Comments” respectively.

Future Customer Meetings

Date	BP-18 Rate Case	Other Workshops
Aug 9 (T)	• Power Rates o Overviews: Market Prices/Loads & Resources o TCMS for NT Secondary o Other	• RHWM Process
Aug 10 (W)	• Transmission Rates • Customer presentation on Cost Allocation • BPA response to proposed error correction process • Risk	

For the most up-to-date calendar of events, please visit the BPA Event Calendar.

Future Customer Meetings

Date	BP-18 Rate Case	Other Workshops
Aug 24 (W)	• Transmission Rates (Tentative) • Power Rates (Tentative)	
Aug 25 (Th)	• Generation Inputs (Tentative)	
Sept 7 (W)	• Transmission Rates (Tentative)	

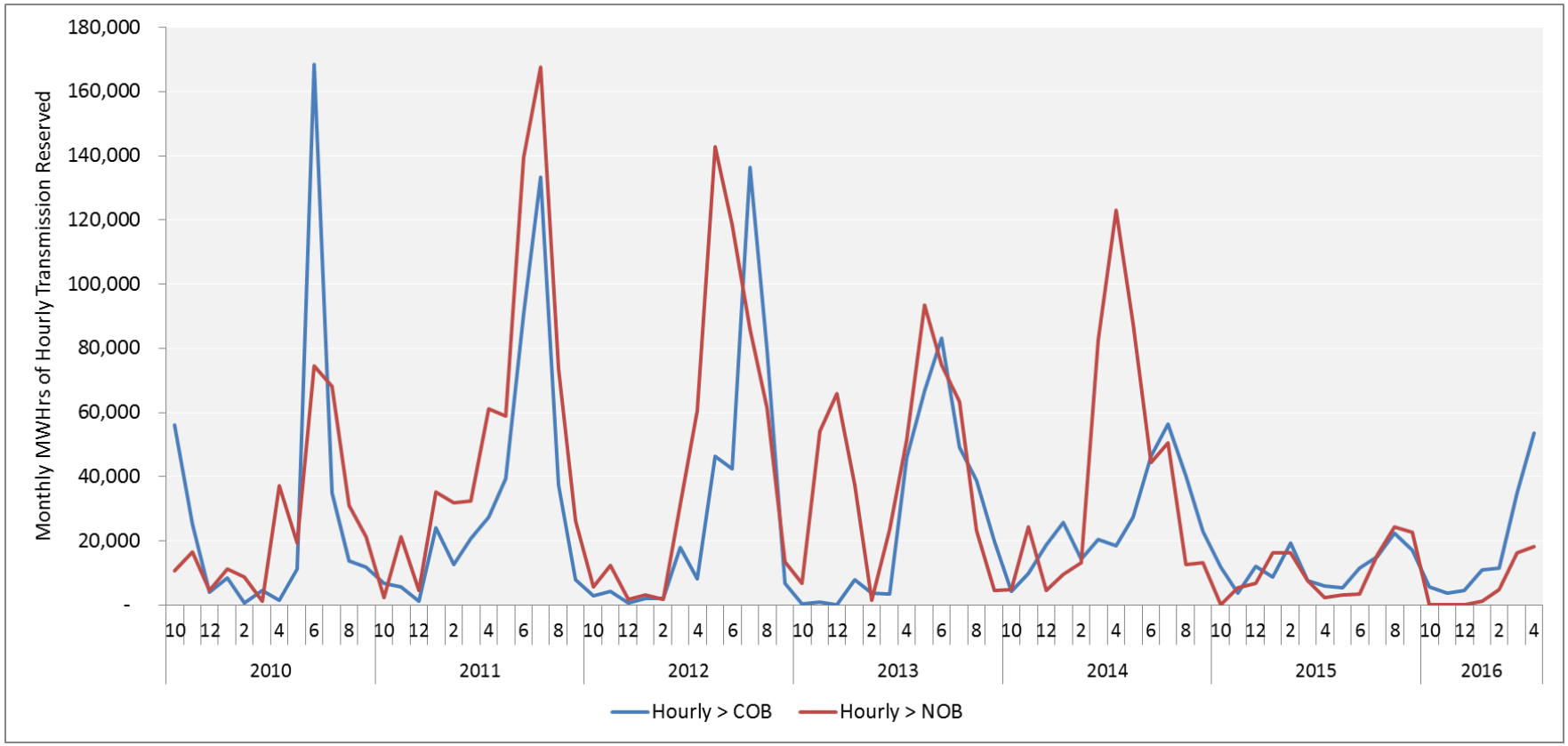
For the most up-to-date calendar of events, please visit the BPA Event Calendar.

Appendix

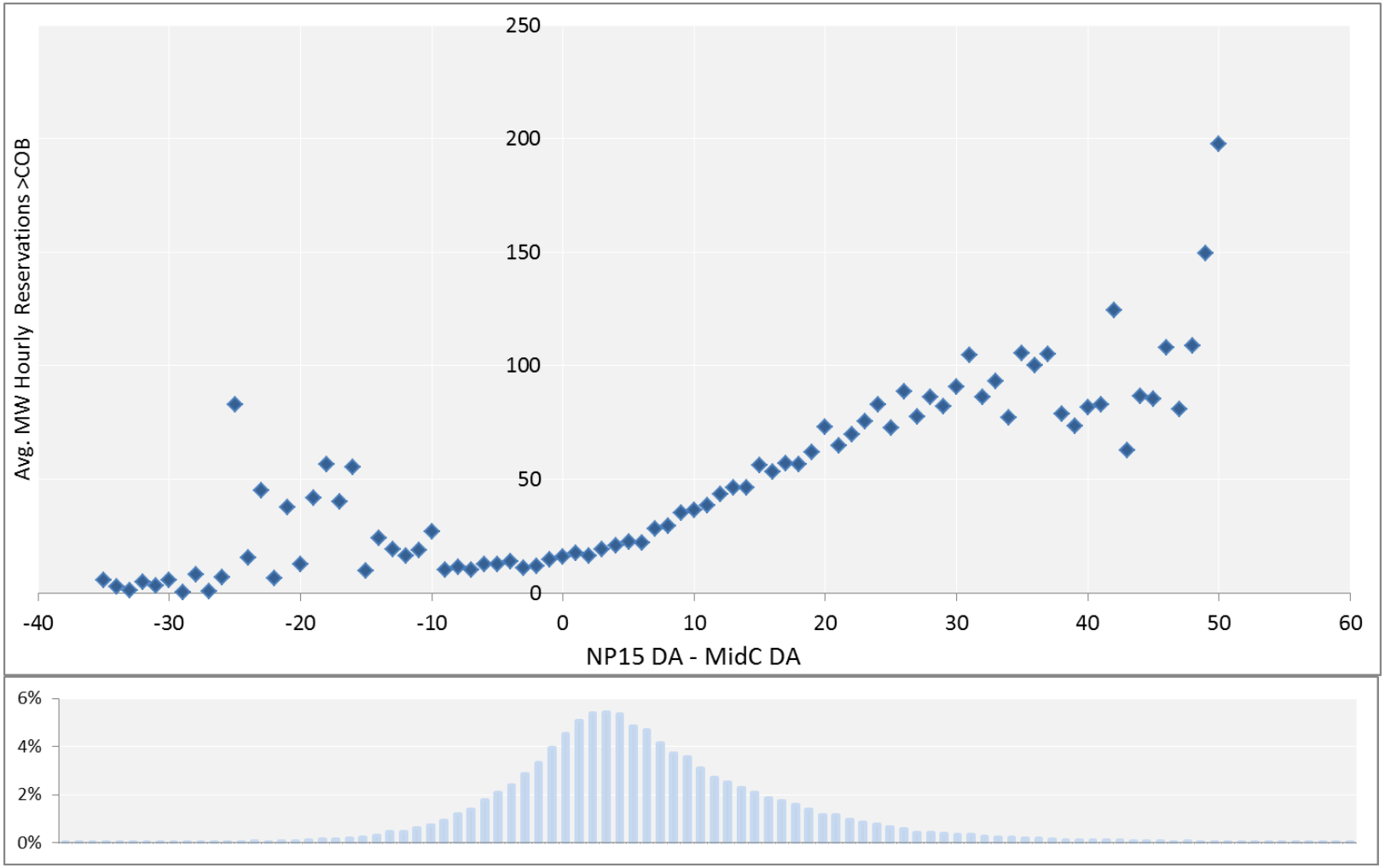
Forecasting Hourly Southern Intertie Transmission

- Hourly reservations on the Southern Intertie are forecasted using a regression based model.
- Regression model estimates a conditional mean and conditional variance as a function of price spreads.
- Reservations to COB are based on price spreads between NP15 and Mid-C.
- Reservations to NOB are based on price spreads between SP15 and Mid-C.
- Raising the hourly non-firm rate has the same effect as a decreased price spread.

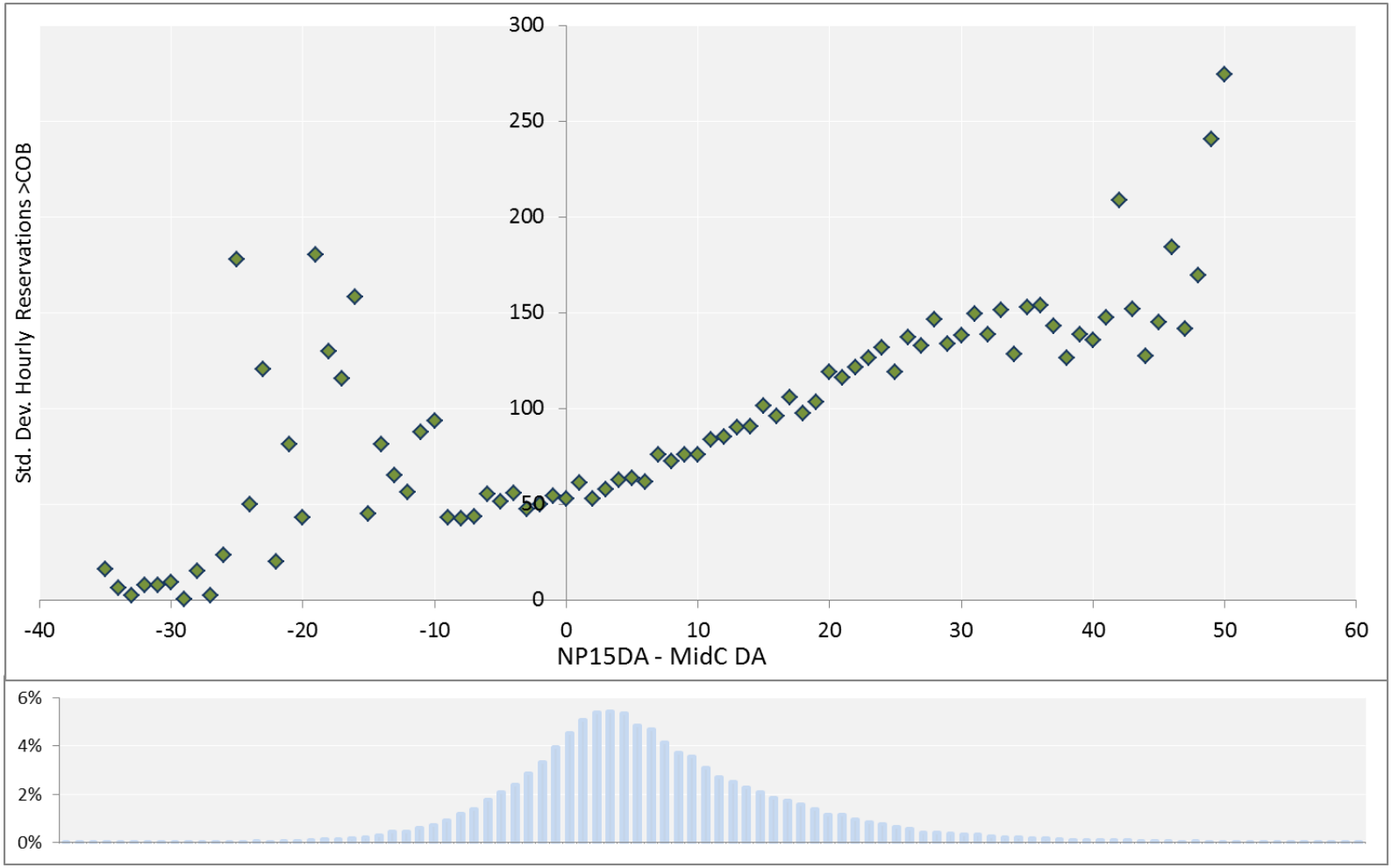
Historical Hourly Southern Intertie Transmission



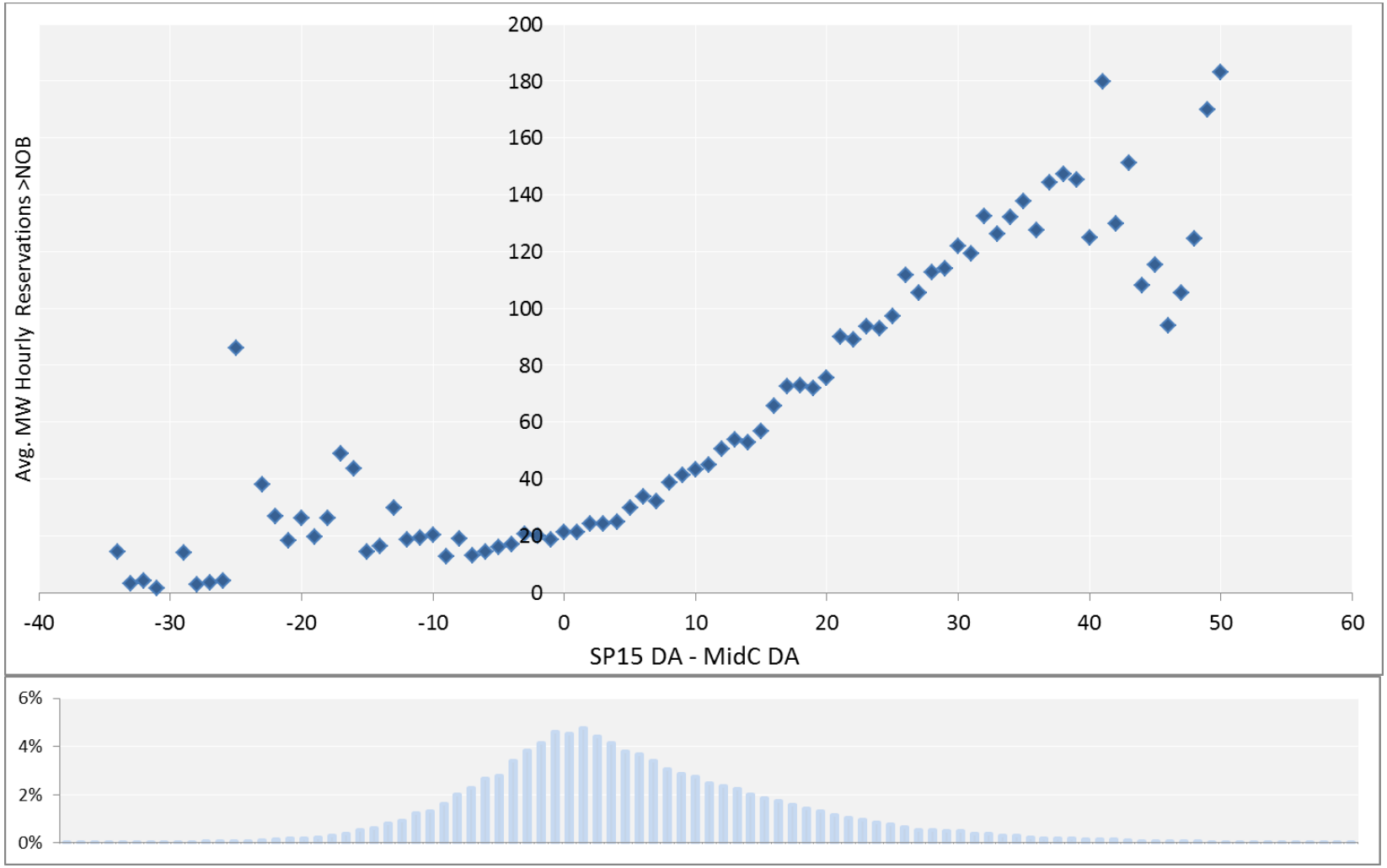
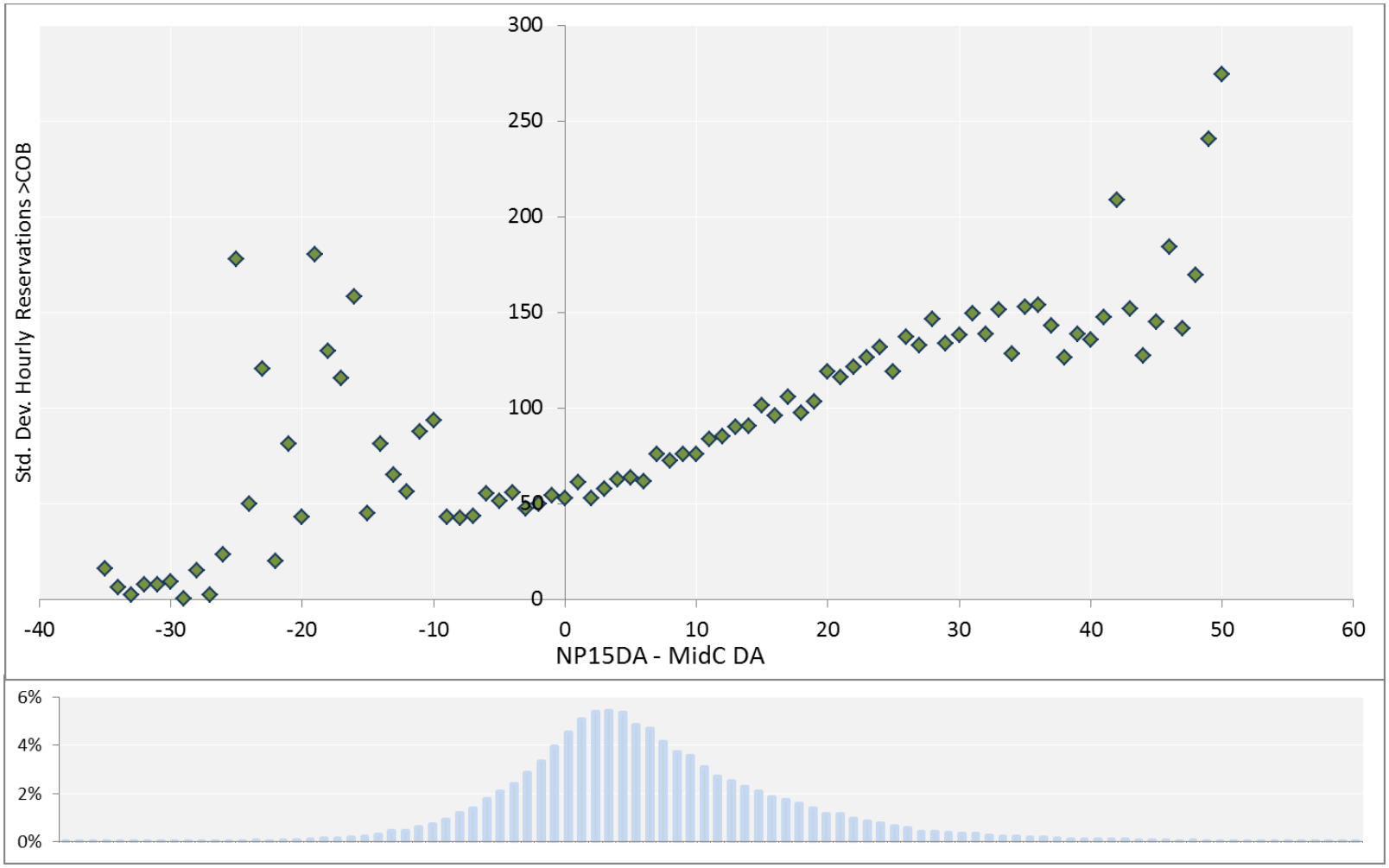
Hourly Average COB Reservations vs Price Spreads



Hourly St Dev of COB Reservations vs Price Spreads



Hourly Average NOB Reservations vs Price Spreads



Hourly St Dev of NOB Reservations vs Price Spreads