BP-20 Rate Case Workshop: Transmission Rates

July 18, 2018

Agenda

- Sales Forecast
- LGIA
- SCD Rate Design
- Proposed Rate Schedule Changes
- Next Steps

Sales Forecast

Sales Forecast Assumptions

- Loads from Agency Load Forecast assume load growth less than 1%.
- Integration of Resources (IR) expires in FY 2018 with PTP LT conversion.
- Formula Power Transmission (FPT) have expirations through FY 2021 without conversion to PTP LT or NT.
- Network Point-to-Point (PTP LT) increase through FY 2021 from deferrals taking service and the forecast of conditional firm.

Sales Forecast

Sales in Monthly average MW	FY 2019		FY 2020	FY 2021
Revenue Product	BP-18 Final	Proposed BP-20 Initial	Proposed BP-20 Initial	Proposed BP-20 Initial
FORMULA POWER TRANSMISSION	901	913	873	873
NETWORK INTEGRATION	6,440	6,477	6,531	6,569
POINT-TO-POINT LONG TERM	26,226	26,037	26,491	27,110
POINT-TO-POINT SHORT TERM	1,234	1,305	1,209	1,177
MONTANA INTERTIE LONG TERM	16	16	16	16
SOUTHERN INTERTIE LONG TERM	6,002	6,050	6,025	6,025
SOUTHERN INTERTIE SHORT TERM	83	134	132	131
UTILITY DELIVERY	167	162	163	163

Note: IR last contract expired in August 2018.

Proposed BP-20 Initial Proposal Revenue Credits

Product Group	Product Category	2019	2020	2021
AC-PNW PSW INTERTIE	SINT AC NON FEDERAL O&M	1,999,824	1,999,824	1,999,824
DSI DELIVERY	DSI DELIVERY CHARGE	1,914,696	1,914,696	1,914,696
FAILURE TO COMPLY	FAILURE TO COMPLY PENALTY	0	0	0
FIBER - OTHER REIMBURSABLE REV	FIBER OPERATIONS & MAINTENANCE	1,533,134	1,578,025	1,583,150
FIBER- OTHER REVENUE	FIBER LEASES	6,960,867	9,088,004	11,949,725
LAND LEASES AND SALES	LAND USE/LEASE/SALE	216,103	216,103	216,103
	RIGHT-OF-WAY LEASE	79,200	79,200	79,200
MISC SERVICES-LOSS-EXCH-AIR	FPS REAL POWER LOSSES	0	0	0
	LATE PAYMENT - INTEREST	0	0	0
	MISC SERVICE FEES	3,312	3,312	3,312
	SERVICE PROCESSING FEES	0	0	0
	TRANSMISSION PROCESSING FEE	39,600	39,600	39,600
NFP - DEPR PNW PSW INTERTIE	AMORT NONFED PNW AC INTERTIE	2,301,420	2,301,420	2,301,420
OPERATIONS & MAINTENANCE	O&M FEDERAL FACILITY	280,976	280,976	280,976
	O&M NON-FEDERAL FACILITY	376,776	376,776	376,776
OTHER MISC LEASES	MISC LEASES	104,859	104,859	104,859
OTHER REVENUE SOURCES	BPA EQUIPMENT USE	178,956	178,956	178,956
REMEDIAL ACTION SCHEME	3RD AC RAS GENERATION DROPPING	56,268	56,268	56,268
RESERVATION FEES	CF RESERVATION FEE	0	0	0
	IS RESERVATION FEE	0	0	0
	PTP RESERVATION FEE	2,463,925	1,801,975	257,425
TOWNSEND-GARRISON TRANS	TGT FIRM DEMAND	12,420,708	12,420,708	12,420,708
TRANSMISSION SHARE OF IPP	TS SHARE OF RES ENRGY - BOR	0	0	0
	TS SHARE OF RES ENRGY/WHLG-COE	245,697	245,697	245,697
UNAUTHORIZED INCREASE	NT UNAUTHORIZED INCREASE	0	0	0
	PTP UNAUTHORIZED INCREASE	0	0	0
USE OF FACILITIES	UFT FIXED DOLLAR AMOUNT	4,681,977	4,676,244	4,676,244
	UFT VARIABLE SERVICE AMT	241,644	241,644	241,644
WIRELESS/PCS - OTHER REVENUE	PCS WIRELESS LEASES	5,966,466	5,966,466	5,966,466
WIRELESS/PCS - REIMBURSABLE	PCS CONSTRUCTION	3,720,000	3,720,000	3,720,000
	PCS DECOMMISSIONING FEE	0	0	0
	PCS OPERATIONS & MAINTENANCE	312,000	312,000	312,000
Grand Total		**46,098,408**	**47,602,753**	**48,925,049**

Proposed BP-20 Initial for FY 2019

FY 2019 (MW)	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	AVG
FPT	935	948	959	934	925	925	918	913	905	866	866	864	**913**
PTP LT	26,247	26,347	26,317	26,307	26,307	26,328	26,328	26,328	26,328	26,328	26,328	26,328	**26,318**
PTP SDD	-288	-288	-280	-280	-280	-280	-280	-280	-280	-280	-280	-280	**-281**
PTP LT Total	**25,959**	**26,059**	**26,037**	**26,027**	**26,027**	**26,048**	**26,048**	**26,048**	**26,048**	**26,048**	**26,048**	**26,048**	**26,037**
IS	6,075	6,075	6,075	6,075	6,075	6,075	6,025	6,025	6,025	6,025	6,025	6,025	**6,050**
IM	16	16	16	16	16	16	16	16	16	16	16	16	**16**
NT, cp	5,887	7,162	8,117	7,855	7,422	6,703	5,934	5,542	5,993	6,479	6,399	5,787	**6,607**
NT SDD	-140	-149	-148	-151	-121	-113	-163	-80	-90	-128	-132	-141	**-130**
NT, CP Total	**5,747**	**7,012**	**7,969**	**7,704**	**7,301**	**6,590**	**5,772**	**5,462**	**5,904**	**6,351**	**6,267**	**5,647**	**6,477**
NT, ncp	7,055	8,163	9,140	9,133	8,549	7,883	7,350	6,629	6,642	7,134	6,996	6,555	**7,603**
NT, SDD	-140	-149	-148	-151	-121	-113	-163	-80	-90	-128	-132	-141	**-130**
NT, ncp Total	**6,915**	**8,014**	**8,992**	**8,982**	**8,428**	**7,770**	**7,187**	**6,549**	**6,552**	**7,006**	**6,864**	**6,414**	**7,473**
PTP ST Block 1	0	0	46	231	298	217	269	563	741	630	70	0	**256**
PTP ST Block 2	0	0	844	583	618	368	571	1,822	1,962	839	1,182	421	**767**
PTP ST Hourly	418	556	275	333	315	170	180	274	387	346	75	55	**282**
PTP ST Total	**418**	**556**	**1,165**	**1,148**	**1,231**	**755**	**1,020**	**2,660**	**3,090**	**1,814**	**1,328**	**476**	**1,305**
IS ST Block 1	14	6	45	23	7	28	21	19	35	30	14	11	**21**
IS ST Block 2	66	76	34	56	81	50	62	60	47	50	65	71	**60**
IS ST Hourly	54	53	55	53	55	51	50	53	55	54	52	52	**53**
IS ST Total	**134**	**134**	**134**	**132**	**143**	**129**	**132**	**132**	**137**	**134**	**131**	**134**	**134**

Note: last IR contract expired in August 2018.

Proposed BP-20 Initial for FY 2020

FY 2020 (MW)	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	AVG
FPT	868	881	892	887	878	878	871	866	858	866	866	864	**873**
PTP LT	26,544	26,727	26,727	26,727	26,721	26,721	26,721	26,821	26,881	26,856	26,856	26,947	**26,771**
PTP SDD	-280	-280	-280	-280	-280	-280	-280	-280	-280	-280	-280	-280	**-280**
PTP LT Total	**26,264**	**26,447**	**26,447**	**26,447**	**26,441**	**26,441**	**26,441**	**26,541**	**26,601**	**26,576**	**26,576**	**26,667**	**26,491**
IS	6,025	6,025	6,025	6,025	6,025	6,025	6,025	6,025	6,025	6,025	6,025	6,025	**6,025**
IM	16	16	16	16	16	16	16	16	16	16	16	16	**16**
NT, cp	5,896	7,181	8,118	7,943	7,506	6,782	5,986	5,587	6,057	6,546	6,468	5,854	**6,660**
NT SDD	-140	-149	-148	-151	-121	-113	-163	-80	-90	-128	-132	-141	**-130**
NT, cp Total	**5,756**	**7,032**	**7,970**	**7,791**	**7,385**	**6,669**	**5,823**	**5,507**	**5,968**	**6,418**	**6,336**	**5,714**	**6,531**
NT, ncp	7,040	8,133	9,110	9,199	8,646	7,943	7,408	6,687	6,701	7,206	7,072	6,632	**7,648**
NT, SDD	-140	-149	-148	-151	-121	-113	-163	-80	-90	-128	-132	-141	**-130**
NT, ncp Total	**6,901**	**7,984**	**8,961**	**9,048**	**8,525**	**7,830**	**7,245**	**6,608**	**6,611**	**7,078**	**6,940**	**6,492**	**7,519**
PTP ST Block 1	0	0	46	198	261	219	257	553	727	614	66	0	**245**
PTP ST Block 2	0	0	622	489	514	371	544	1,788	1,923	818	1,119	376	**714**
PTP ST Hourly	349	468	216	273	249	171	171	269	380	337	71	49	**250**
PTP ST Total	**349**	**468**	**884**	**961**	**1,024**	**761**	**972**	**2,610**	**3,030**	**1,770**	**1,256**	**425**	**1,209**
IS ST Block 1	14	6	45	24	8	28	21	19	35	30	14	11	**21**
IS ST Block 2	66	76	34	56	81	50	62	60	47	50	65	71	**60**
IS ST Hourly	55	53	49	49	53	49	49	50	53	54	51	51	**51**
IS ST Total	**134**	**134**	**128**	**129**	**142**	**128**	**132**	**128**	**135**	**134**	**130**	**132**	**132**

Note: last IR contract expired in August 2018.

Proposed BP-20 Initial for FY 2021

FY 2021 (MW)	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	AVG
FPT	868	881	892	887	878	878	871	866	858	866	866	864	**873**
PTP LT	27,038	27,138	27,138	27,463	27,463	27,463	27,486	27,486	27,485	27,485	27,485	27,546	**27,390**
PTP SDD	-280	-280	-280	-280	-280	-280	-280	-280	-280	-280	-280	-280	**-280**
PTP LT Total	**26,758**	**26,858**	**26,858**	**27,183**	**27,183**	**27,183**	**27,206**	**27,206**	**27,205**	**27,205**	**27,205**	**27,266**	**27,110**
IS	6,025	6,025	6,025	6,025	6,025	6,025	6,025	6,025	6,025	6,025	6,025	6,025	**6,025**
IM	16	16	16	16	16	16	16	16	16	16	16	16	**16**
NT, cp	5,946	7,188	8,117	7,910	7,464	6,787	6,005	5,659	6,164	6,661	6,570	5,916	**6,699**
NT SDD	-141	-150	-149	-152	-122	-113	-164	-80	-90	-129	-133	-141	**-130**
NT, cp Total	**5,806**	**7,038**	**7,968**	**7,758**	**7,342**	**6,674**	**5,841**	**5,579**	**6,074**	**6,532**	**6,437**	**5,775**	**6,569**
NT, ncp	7,110	8,160	9,145	9,190	8,671	7,965	7,498	6,845	6,875	7,369	7,231	6,756	**7,735**
NT SDD	-141	-150	-149	-152	-122	-113	-164	-80	-90	-129	-133	-141	**-130**
NT, ncp Total	**6,970**	**8,010**	**8,996**	**9,038**	**8,549**	**7,852**	**7,334**	**6,765**	**6,785**	**7,241**	**7,098**	**6,615**	**7,604**
PTP ST Block 1	0	0	46	195	257	224	232	543	719	596	63	0	**240**
PTP ST Block 2	0	0	599	479	503	380	492	1,755	1,902	794	1,062	327	**691**
PTP ST Hourly	359	471	210	267	242	175	155	264	376	327	67	43	**246**
PTP ST Total	**359**	**471**	**854**	**941**	**1,002**	**779**	**879**	**2,561**	**2,996**	**1,717**	**1,193**	**370**	**1,177**
IS ST Block 1	14	6	45	23	7	28	21	19	35	30	14	11	**21**
IS ST Block 2	65	76	35	56	81	50	62	60	47	50	65	71	**60**
IS ST Hourly	53	52	47	49	51	48	45	50	52	52	49	51	**50**
IS ST Total	**132**	**134**	**127**	**128**	**139**	**127**	**127**	**128**	**134**	**131**	**128**	**132**	**131**

Note: last IR contract expired in August 2018.

LGIA

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-20 Transmission Credit Forecast Results

- BPA currently holds $112 million in funds advanced for Network Upgrades that are currently receiving Transmission Credits. BPA holds an additional $3.5 million in funds advanced for Network Upgrades for projects that have not begun receiving Transmission Credits.

- For the BP-20 rate period, BPA is forecasting approximately $26 million in additional funds advanced for Network Upgrades for continuing and future interconnection projects.

- The average interest expense is $4.1 million per year in FY 20-21.

- The average transmission credit is $17.1 million per year in FY 20-21.

BP-20 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 1-9)
2. Projects where the credit repayment forecast is based on TSRs or Generator Nameplate (rows 10-20)
3. Some projects in forecast only receive interest during rate period.

BP-20 Transmission LGIA Credit and Interest Forecast

				Forecasted Transmission Credit			Forecasted Interest		
#	Request	Tx Credit Balance as of 6/1/2018	Upgrade Deposits During FY19-22	FY 2019	FY 2020	FY 2021	FY 2019	FY 2020	FY 2021
1	GI Request 1	$ 11,689	$ -	$ 4,663	$ 4,663	$ 1,420	$ 283	$ 124	$ 6
2	GI Request 2	$ 12,855	$ -	$ 728	$ 728	$ 728	$ 471	$ 462	$ 451
3	GI Request 3	$ 3,439	$ -	$ 873	$ 873	$ 873	$ 107	$ 77	$ 46
4	GI Request 4	$ 2,848	$ -	$ 958	$ 958	$ 937	$ 134	$ 82	$ 25
5	GI Request 5	$ 65,460	$ -	$ 5,938	$ 5,938	$ 5,938	$ 2,221	$ 2,087	$ 1,947
6	GI Request 6	$ 849	$ -	$ 318	$ 318	$ 160	$ 23	$ 12	$ 1
7	GI Request 7	$ 646	$ -	$ 265	$ 265	$ 17	$ 24	$ 8	$ -
8	GI Request 8	$ 1,231	$ -	$ 281	$ 281	$ 281	$ 65	$ 52	$ 37
9	GI Request 9	$ 12,855	$ -	$ 353	$ 1,294	$ 2,001	$ 434	$ 420	$ 381
10	GI Request 10	$ -	$ 14,260	$ -	$ 471	$ 1,883	$ 466	$ 543	$ 515
11	GI Request 11	$ -	$ 848	$ -	$ 147	$ 925	$ 24	$ 34	$ 15
12	GI Request 12	$ -	$ 5,700	$ -	$ -	$ 1,080	$ 195	$ 234	$ 222
13	GI Request 13	$ -	$ 200	$ 111	$ 97	$ -	$ 5	$ 1	$ -
14	GI Request 14	$ -	$ 250	$ 9	$ 118	$ 143	$ 9	$ 7	$ 2
15	GI Request 15	$ -	$ 250	$ 9	$ 118	$ 138	$ 5	$ 6	$ 2
16	GI Request 16	$ -	$ 2,000	$ 9	$ 118	$ 188	$ 86	$ 138	$ 137
17	GI Request 17	$ -	$ 370	$ -	$ 118	$ 188	$ 8	$ 11	$ 6
18	GI Request 18	$ -	$ 1,520	$ -	$ 118	$ 188	$ 33	$ 51	$ 48
19	GI Request 19	$ -	$ 300	$ 9	$ 118	$ 188	$ 6	$ 8	$ 3
20	GI Request 20	$ -	$ 208	$ -	$ 29	$ 188	$ 3	$ 7	$ 5
21	**Total**	**$ 111,872**	**$ 25,906**	**$ 14,523**	**$ 16,768**	**$ 17,465**	**$ 4,602**	**$ 4,363**	**$ 3,849**

	Forecasted Credit	Forecasted Intertest
FY 2019	$14,523	$4,602
FY 2020	$16,768	$4,363
FY 2021	$17,465	$3,849
Total	**$48,756**	**$12,814**

SCD Rate Design

Opportunity for the SCD Rate Design

Background:

The Scheduling, System Control and Dispatch (SCD) charge was originally designed and settled in the TR-02 rate case. In our initial proposal BPA looked at several options based on cost causation. BPA was originally leaning toward using a schedule based charge, but eventually settled on using reservations and meters due to ease and simplicity to implement.

Opportunity:

With the changing environment, markets and technology, along with BPA's Agency Strategy goal to implement polices, pricing and procedures for regional planning that incentivize grid optimization and efficient regional resource development, we thought now was an opportunity to review the pricing for the SCD. It has been over 16 years since we last reviewed the SCD rate design, and we want to ensure it is priced on the value it brings based on the function the services provide.

Principles for Rate Design

- Full and timely cost recovery.
- Lowest possible rates consistent with sound business principles.
- Cost causation – fairly allocate costs to customers based on proportionate use.
- Statutory requirement of equitable allocation.
- Simplicity, understandability, public acceptance, and feasibility of application.
- Avoid rate shock and maintain rate stability from rate period to rate period (e.g., magnitude of rates and rate design).

What is the Current SCD Rate Design?

- SCD is an Ancillary Service required to schedule the movement of power through, out of, within, or into a Control Area.
- Transmission customers must purchase this service from the control area.
- The segmented revenue requirement calculates the costs for SCD after taking revenue credits and other adjustments into account.
- The adjusted SCD is then prorated to the NT, PTP and IR for the Network and the Interties.
- The costs allocated to the NT, PTP and IR are then divided by their billing determinant to get the associated rate.
- All costs for SCD are fully recovered.

What Alternatives were Considered?

- **Status quo:** SCD is segmented and then allocated to the Network and Interties based on reserved PTP capacity and NT load.

- **Option 1: Segmented with allocation to Network only:** SCD is segmented and then allocated to the Network only, based on reserved PTP capacity and NT load.

- **Option 2: Transmission schedules and energy without segments:** SCD is allocated based on transmission schedules or total energy on a cost per MWh basis. This alternative does not charge twice for a schedule over multiple segments.

- **Option 3: Transmission schedules and energy including segments:** SCD is allocated based on transmission schedules or total energy on a cost per MWh basis. This alternative does charge twice for a schedule over multiple segments.

Rate Impacts of SCD Alternatives

- Analysis is based on FY 2017 billing quantities, schedule data and meter data.
- We analyzed how the different SCD alternatives would have shifted costs of SCD among customers.
- Customer level impacts and historical data are posted on the BP-20 Meetings and Workshops page.

Analysis Methodology

Option 1 – Recalculated BP-16 Final Proposal rates assuming that the Southern Intertie and Montana Intertie are not allocated any costs. Used actual FY 2017 billing quantities to calculate rates.

Option 2 & 3 – Calculated a $/MWh charge required to hold SCD revenues equal to FY 2017 actuals.

Rate Impacts by Customer Type

SCD Revenue by Customer Type ($000)

Customer Type	Status Quo Revenue	Option 1 Revenue	Option 2 Revenue	Option 3 Revenue
NT_Only	$ 19,096	$ 22,395	$ 23,062	$ 20,841
PTP_Only	$ 61,717	$ 72,269	$ 56,591	$ 49,779
PTP_&_NT	$ 9,775	$ 11,464	$ 11,167	$ 10,090
IS_Only	$ 3,132	$ 107	$ 4,014	$ 5,650
Network_&_IS	$ 44,951	$ 30,887	$ 46,885	$ 56,499
Network_IS_&_IM	$ 14,770	$ 16,388	$ 11,498	$ 10,391
No_LongTermTx	$ 179	$ 112	$ 403	$ 370
Total	$ 153,621	$ 153,621	$ 153,621	$ 153,621

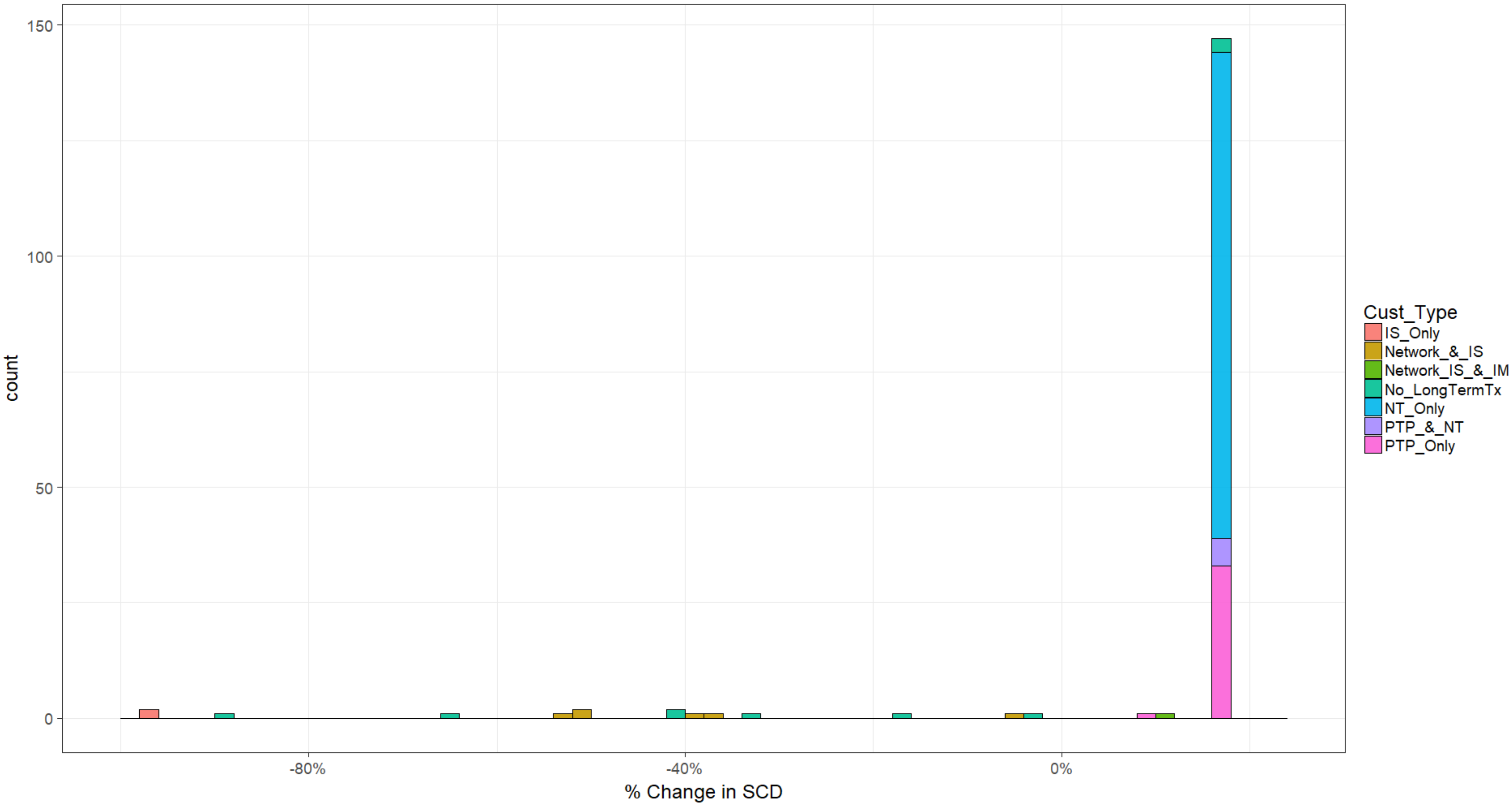
% Change in SCD Revenue by Customer Type

Customer Type	Option 1 Revenue	Option 2 Revenue	Option 3 Revenue
NT_Only	17.3%	20.8%	9.1%
PTP_Only	17.1%	-8.3%	-19.3%
PTP_&_NT	17.3%	14.2%	3.2%
IS_Only	-96.6%	28.2%	80.4%
Network_&_IS	-31.3%	4.3%	25.7%
Network_IS_&_IM	11.0%	-22.2%	-29.6%
No_LongTermTx	-37.4%	125.8%	106.9%

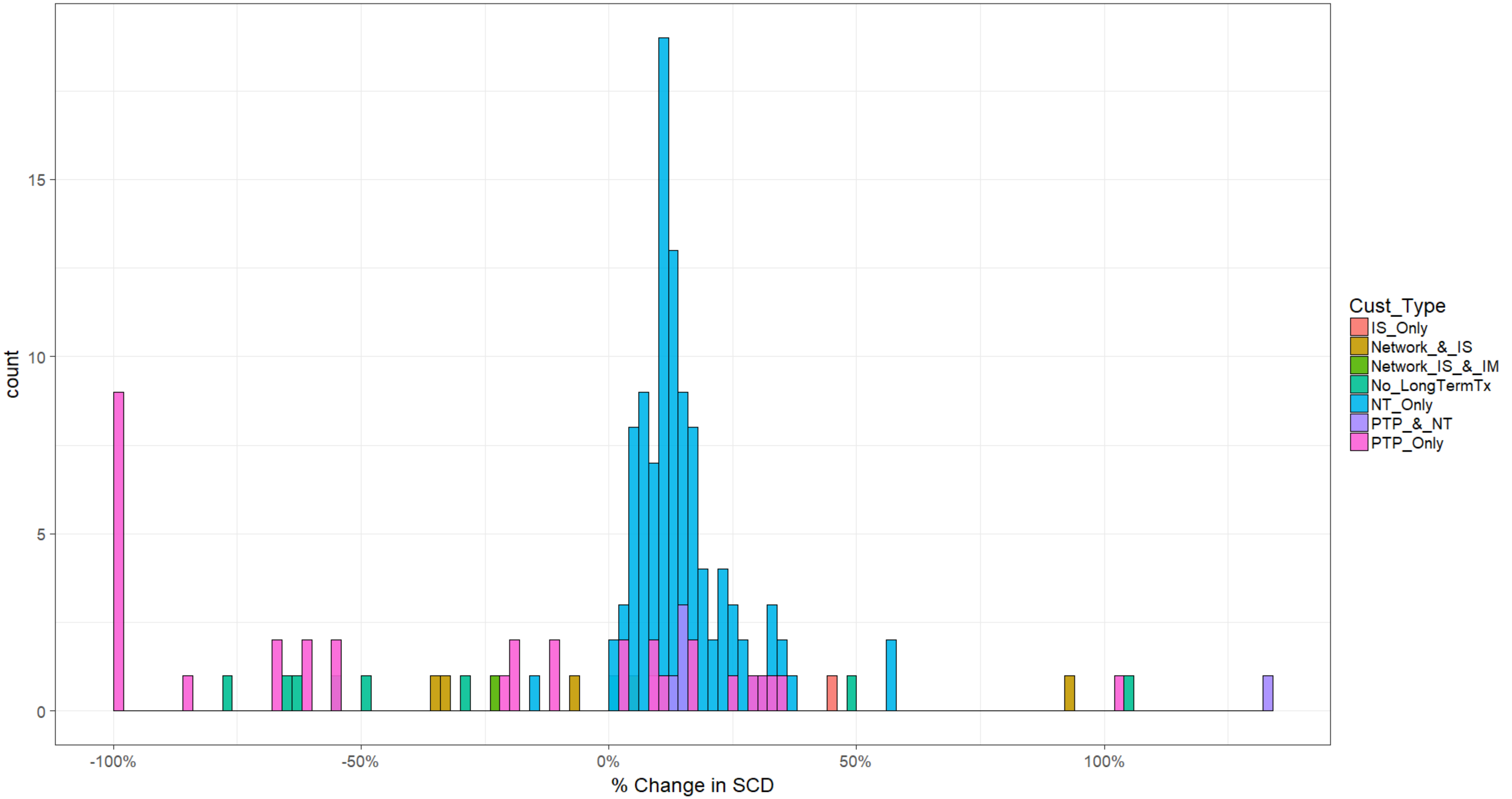
Customer Type Descriptions

NT Only - Customers that have NT service and do not have long term PTP or long term IS.
PTP Only - Customers that have PTP service and do not have NT service or long term IS.
PTP_&_NT - Customers that have NT service and PTP Service and do not have long term IS.
IS_Only - Customers that have long term IS and do not have long term PTP or NT service.
Network_&_IS - Customers that have IS long term and either NT service or PTP service.
Network_IS_&_IM - Customers that have IS long term, IM long term and either NT service or PTP service.
No_LongTermTx - Customers that do not have and long term PTP, long term IS or NT service.

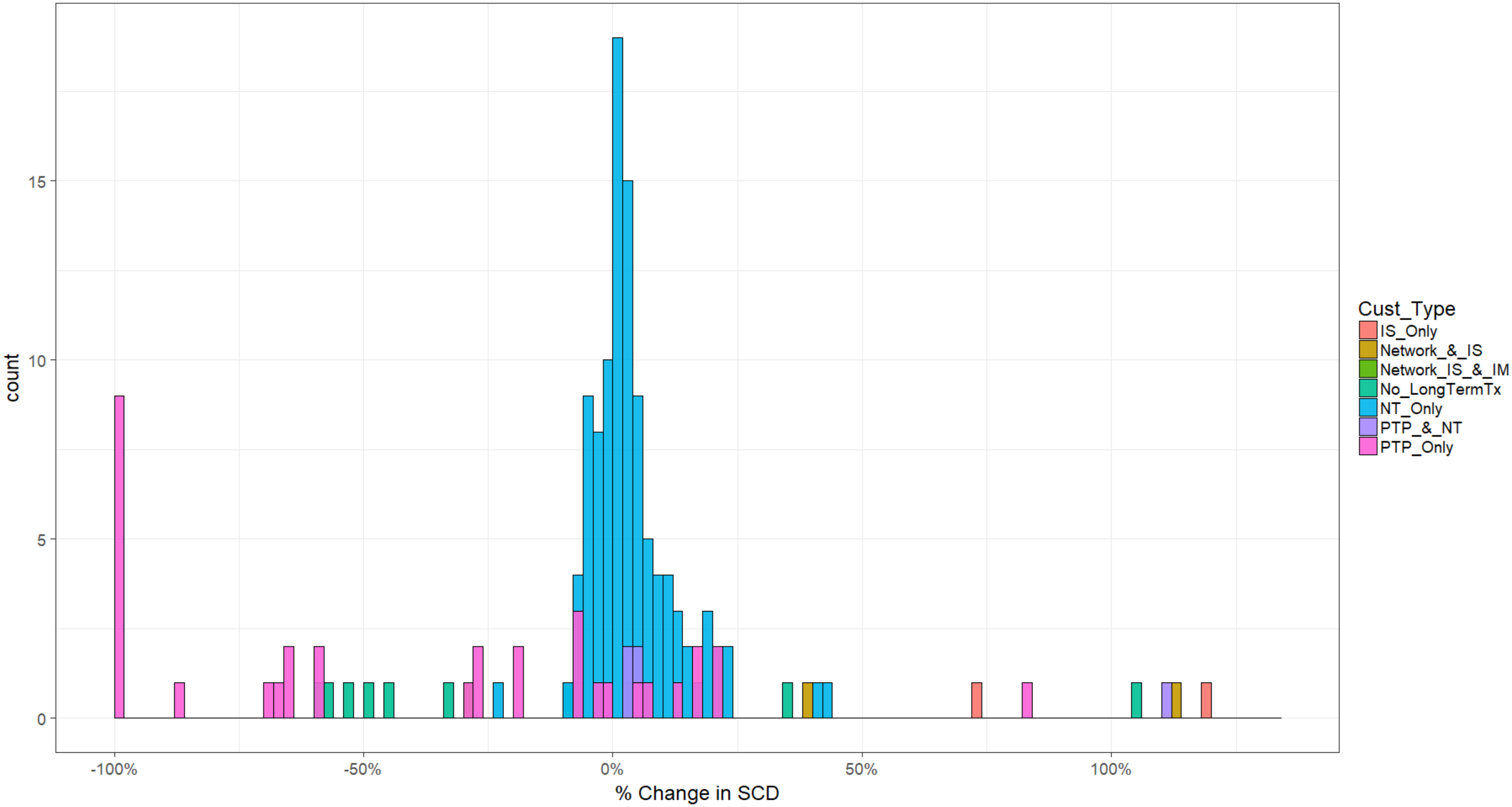
Option 1: Histogram of Rate Impacts



Option 2: Histogram of Rate Impacts



Option 3: Histogram of Rate Impacts



How do the Alternatives Meet the Rate Principles?

- All fully recover costs
- Some may be closer to cost causation than others
- All meet statutory requirements

What is Staff's Leaning?

- We appreciate and understand the questions and concerns customers raised in their comments.
- We believe there is an opportunity to design an SCD rate that will better reflect the value of the service.
- After review of the TR-02 Initial Proposal and consideration of customer comments, staff is leaning toward recommending charging the SCD based on use of the scheduling system (Option 2).
- Moving to a charge based on the use of the scheduling system is better aligned with cost causation.
- Customers will have an opportunity to submit feedback on the analysis and staff's leaning (see Next Steps slide).

Proposed Rate Schedule Changes

Proposed Rate Schedule Changes

- Customers supported the proposed rate schedule changes presented at the June 14 workshop.

- An updated draft redline version of the proposed changes to the BP-20 Transmission Rate Schedules is posted on the BP-20 Meetings and Workshops page. The updated draft adds the following change:
  - Elimination of the IR rate schedule since all IR contracts expired in the prior rate period and BPA is no longer offering any new IR contracts (Legacy); all future service offers are OATT based.

Next Steps

- The next BP-20 Rate Case Workshop is July 25, 2018.
  - Power Rates
  - Revenue Requirements for Power and Transmission
  - Preliminary Initial Proposal rate estimates for Power and Transmission
- SMUD will present on Southern Intertie concerns after the July 25, 2018 BP-20 Rate Case Workshop.
- Please submit comments to techforum@bpa.gov with the subject line “Rate Schedule Changes” or “SCD Staff Leaning” by August 1, 2018.

Future Customer Meetings

Date	BP-20 Rate Case Workshops	Other Meetings
July 23 (M)		• TC-20 Tariff Workshop
July 25 (W)	• Power Rates o Tier 2 pricing o Transmission Scheduling Service • Power and Transmission Rates o Revenue Requirements o Repayment modeling o Preliminary rate estimates for Initial Proposal • Other related discussion topics o Update on preferred capital financing scenario from May 22 workshop o SMUD presentation on the Southern Intertie	• RHWM Process (9am-10am)
Aug 8 (W)	• Risk • Power Rates • Transmission Rates • ACS Practices Workshop (tentative)	
Aug 22 (W)	• BP-20 Rate Case (if needed)	

Appendix

LGIA Background

- LGIA 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