TC-22, BP-22 and EIM Phase III Customer Workshop

July 29 & 30, 2020

Day 2 and 3

Pre-decisional. For Discussion Purposes Only.

AGENDA REVIEW

Agenda

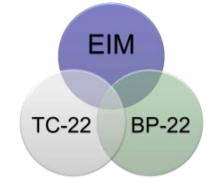
Day 2 – July 29, 2020		
TIME*	**TOPIC**	**Presenter**
9:00 to 9:30 a.m.	Transmission Rates • Sales • Loads • LGIA	Danny Chen Araceli Contreras Glen Booth Todd Foxall Angie Robertson
9:30 to 11:00 a.m.	Transmission Rates • Rates design ○ EIM Charge Code Cost Allocation Implementation	Miranda McGraw Derrick Pleger Libby Kirby Eric Taylor Alex Lennox
Day 3 – July 30, 2020		
TIME*	**TOPIC**	**Presenter**
9:00 to 11:30 a.m.	Power Rates • Tier 2 Rates • EIM Benefits and Charges in Power Rates	John Wellschlager Emily Traetow Daniel Fisher Emily Traetow James Vanden Bos John Wellschlager

** Times are approximate*

EIM Priority Issues

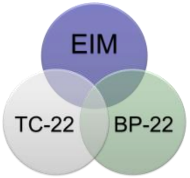
#	Issue	BP-22	TC-22	Future BP/TC
1	EIM Charge Code Allocation	X	?	X
2	EIM Losses	X	X	?
3	Resource Sufficiency	X	X	?
3a	- Balancing Area Obligations	X	X	?
3b	- LSE Performance & Obligations	X	X	?
3c	- Gen Input Impacts	X	X	?
4	Development of EIM Tariff Changes		X	?
5	Transmission Usage for Network	X	X	?
6	Requirements for Participating & Non-Participating Resources	X	X	?
6a	- Participating Resources: Base Scheduling Timeline			
7	Metering & Data Requirements		X	?
8	Evaluation of Operational Controls	X	X	?

Rates & Tariff Topics



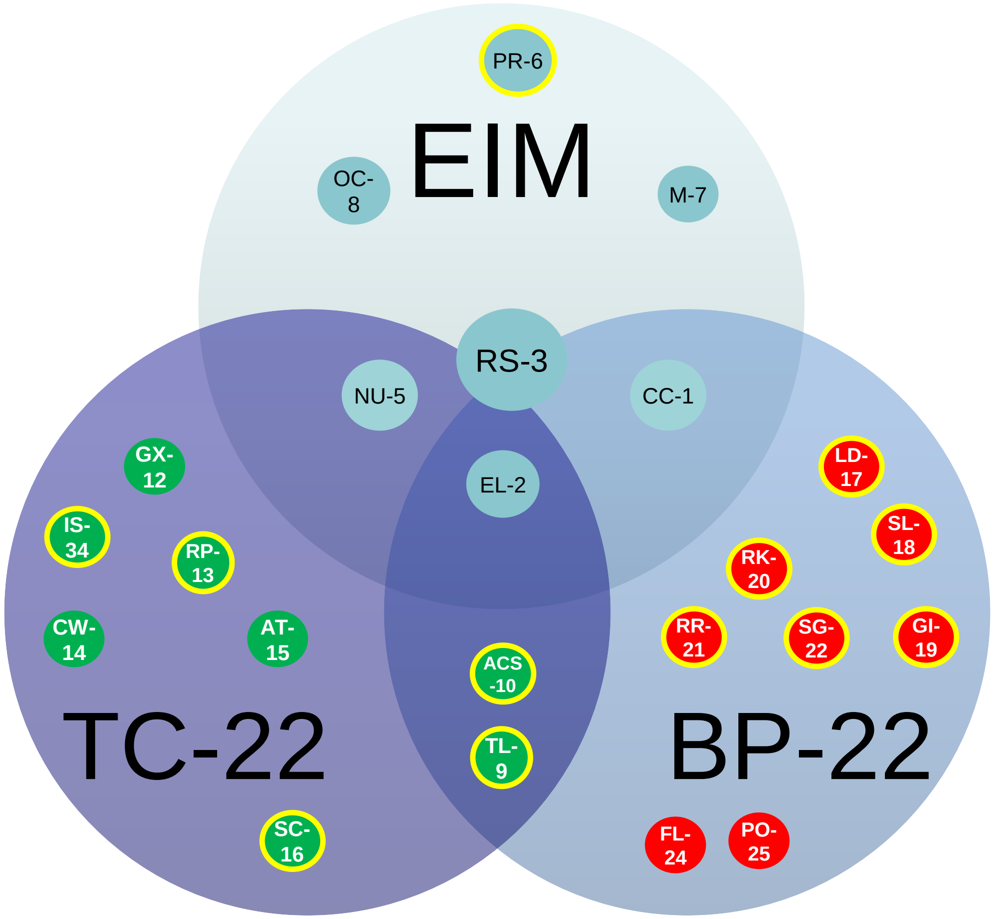
#	Topics	BP-22	TC-22	Future BP/TC
9	Transmission Losses	X	X	
10	Ancillary Services	X		?
11	Debt Management (Revenue Financing)	X		
12	Generator Interconnection		X	
13	Regional Planning		X	
14	Creditworthiness		X	
15	Incremental/Minor Changes to Agreement Templates		X	
16	Seller's Choice		X	
17	Loads	X		
18	Sales	X		
19	Generator Interconnection (assumed for BP-22)	X		
20	Risk	X		
21	Revenue Requirements	X		
22	Review of Segments	X		
23	Review of Sale of Facilities	X		
24	Financial Leverage Policy Implementation	X		
25	Power-Only issues	X		

Potential Future Rates & Tariff Issues



#	Issue	BP-22	TC-22	Future BP/TC
26	Simultaneous Submission Window			?
27	Study Process			?
28	Attachment C (Short-term & Long-term ATC)			?
29	Hourly Firm (TC-20 Settlement – Attachment 1: section 2.c.ii)			?
30	Required Undesignation			?
31	Reservation window for Hourly non-firm			?
32	Non-federal NT Redispatch			?
33	PTP/NT Agreement Templates			?
34	Intertie Studies			?
35	De minimus (TC-20 Settlement)			?

BP-22, TC-22 & EIM Integrated Scope



TC

TL-9	Transmission Losses
ACS-10	Ancillary Services
GX-12	Generator Interconnection
RP-13	Regional Planning
CW-14	Creditworthiness
AT-15	Agreement Templates
SC-16	Seller's Choice
IS-34	Intertie Studies

BP

LD-17	Loads
SL-18	Sales
GI-19	Gen Inputs
RK-20	Risk
RR-21	Revenue Requirements
SG-22	Segmentation
FL-24	Financial Leverage
PO-25	Power-only

EIM

CC-1	Charge Code Allocation
EL-2	EIM Losses
RS-3	Resource Sufficiency
NU-5	Network Usage
PR-6	Participating Resources
M-7	Metering
OC-8	Operational Controls

XX-#

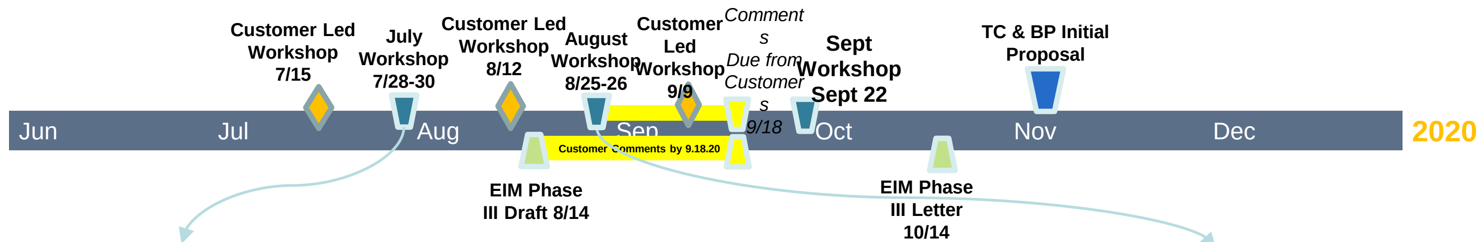
Yellow Outline Denotes Current Workshop Topics

WORKPLAN AND PROPOSAL

Engaging the Region on Issues

- After every workshop, BPA will provide a two-week feedback period for customers.
  - Input can be submitted via email to techforum@bpa.gov. Please copy your Power or Transmission Account Executive on your email.
- Issues will be presented according to the following process at workshops (multiple steps might be addressed in a single workshop):

Phase One: Approach Development	Phase Two: Evaluation	Phase Three: Proposal Development
Step 1: Introduction & Education Step 2: Description of the Issue	Step 3: Analyze the Issue Step 4: Discuss Alternatives	Step 5: Discuss Customer Feedback Step 6: Staff Proposal



July 28-30, 2020

- Seller's Choice (SC-16)
  - Steps 5-6
- Generator Interconnection (GX-12)
  - Steps 5-6
- Generation Inputs: Energy Imbalance, Generation Imbalance, Persistent Deviation and Intentional Deviation (ACS-10)
  - Steps 1-4
- Requirements for Participating Resources & Non-participating Resources (PR-6)
  - Steps 5-6 – Enabling Agreement
  - Steps 5-6 – Transmission Reservations
- Participating Resources: Base Schedule Timeline (PR-6)
  - Steps 5-6
- Review Tariff red line (GI-19)
- Revenue Requirement
- Transmission Rates (SL-18)
  - Sales
  - LGIA (LD-17)
  - EIM Charge Code Implementation
- Power Rates (RR-21)
  - Tier 2 Rates
  - EIM Benefits and Charges in Base Power Rates
- Southern Intertie Studies

Phase III EIM Draft Letter (8/14):

Decision Finalized in EIM Letter

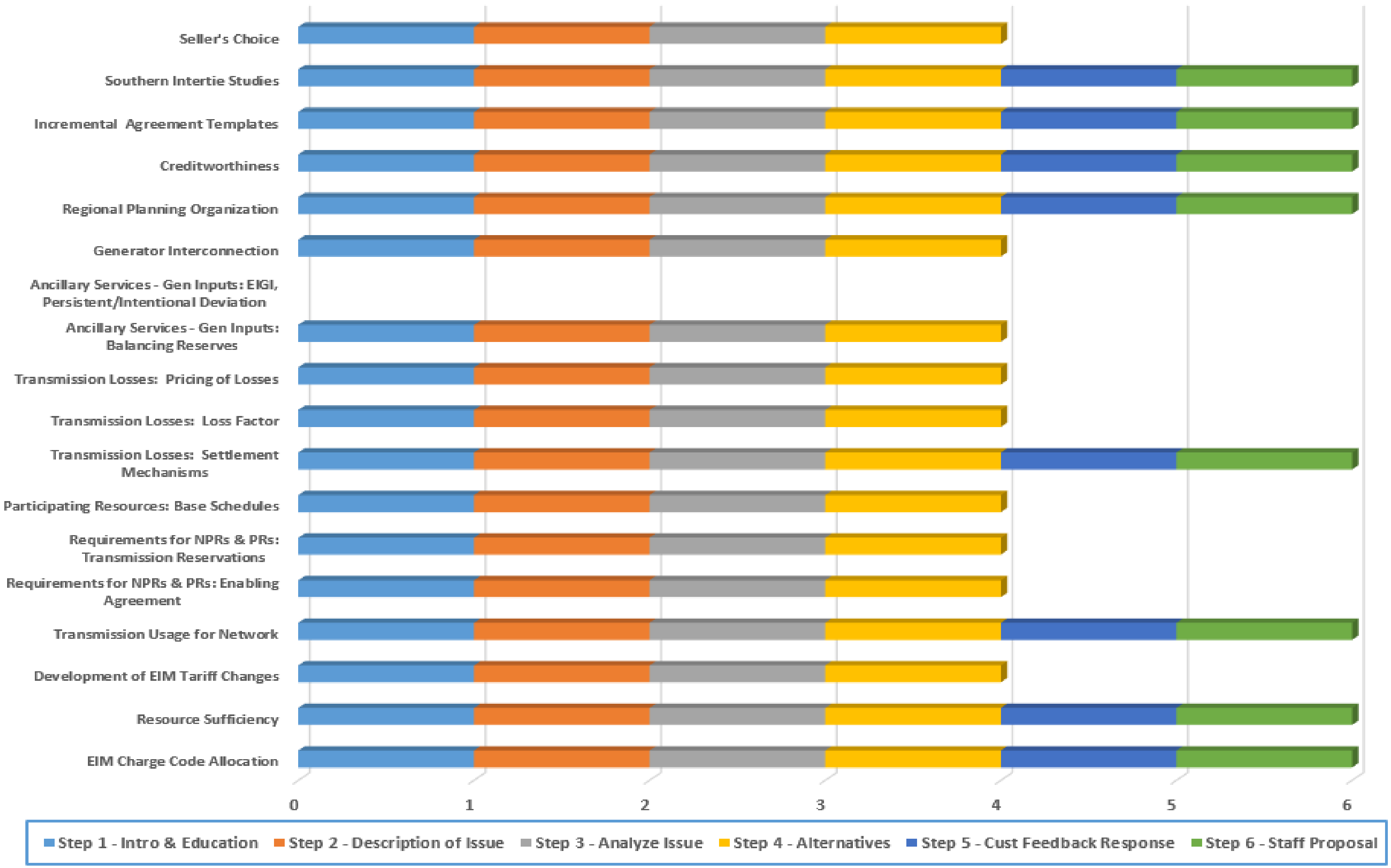
- Sub Allocation of Resource Sufficiency
- Non Federal Resource Participation
- Metering
- EIM Losses

Other decisions that will be part of the Tariff or Rate Case

August 25-26, 2020

- Summary of Topics & Policy – Staff Leaning through the end of August
- Transmission Losses steps 5 & 6
  - Loss Factor
  - Pricing (TL-9)
- Draft Transmission Rates
  - Rate Schedules
  - Rates Modeling (RK-20)
  - EIM Charge Code Implementation (RR-21)
  - Cost Recovery of Losses (SG-22)
- Ancillary Services: Generation Inputs (ACS-10)
  - Steps 5-6
- Power Rates
  - Loads & Resources
  - Gas and Market Price Forecasts
  - Secondary Revenue Forecast
  - Transfer Service
  - Follow-up: Treatment of EIM Charge Codes
  - Follow-up: Section 7(f) Power Rate Options
  - Net Secondary Revenue Proposal

Status of Topics as of 7/27/20



ISSUE: TRANSMISSION RATES

Sales

Loads

LGIA

Rate Design – EIM Charge Code Cost Allocation Implementation

BP-22 Initial Proposal Preliminary Sales and Revenues Forecast

Transmission Preliminary Sales Forecast Assumptions

- No assumed rate design changes from BP-20 rate case.
- Loads from Agency Load Forecast assume load growth 0.9% through the BP-22 rate period.
- Deferral and Renewal forecast of point-to-point long term informed by AE inputs.
- New service related to TSEP and conditional firm service informed by subject matter experts and AE inputs.
- Network Conversions from PTP LT to NT service for customer(s) expressing interest.
- Short Term – average water from TDA hydro study and average price spreads from Aurora.

Transmission Preliminary Sales Forecast

			BP-20 RATE CASE			BP-22 INITIAL PROPOSAL				BP22 vs BP20
ProductGroup	ProductCategory	ProductName	2,020	2,021	AVG	2,021	2,022	2,023	AVG	Delta
NETWORK	FORMULA POWER TRANSMISSION	FPT 1YR LONG TERM FIRM	804	804	804	804	804	804	804	0
		FPT 3YR LONG TERM FIRM	76	76	76	76	76	76	76	0
	FORMULA POWER TRANSMISSION Total		**880**	**880**	**880**	**880**	**880**	**880**	**880**	**0**
	NETWORK INTEGRATION	NT SERVICE CHARGE	6,660	6,699	6,680	6,455	7,129	7,246	7,188	508
		NT SHORT DISTANCE DISCOUNT	(130)	(130)	(130)	(107)	(107)	(107)	(107)	23
	NETWORK INTEGRATION Total		**6,531**	**6,569**	**6,550**	**6,348**	**7,022**	**7,139**	**7,081**	**531**
	POINT-TO-POINT LONG TERM	PTP LONG TERM FIRM	25,389	26,787	26,088	26,455	26,093	26,262	26,177	89
		PTP LTF CANADIAN ENTITLEMENT	1,279	1,279	1,279	1,120	1,120	1,120	1,120	(159)
		PTP SHORT DISTANCE DISCOUNT	(312)	(312)	(312)	(290)	(290)	(290)	(290)	22
	POINT-TO-POINT LONG TERM Total		**26,356**	**27,754**	**27,055**	**27,285**	**26,923**	**27,091**	**27,007**	**(48)**
	POINT-TO-POINT SHORT TERM	PTP DAILY FIRM DAYS 1-5	284	276	280	280	267	274	270	(9)
		PTP DAILY FIRM DAYS 6+	744	723	733	769	763	729	746	13
		PTP HOURLY NONFIRM	245	240	242	258	255	240	248	5
	POINT-TO-POINT SHORT TERM Total		**1,273**	**1,239**	**1,256**	**1,308**	**1,285**	**1,244**	**1,264**	**8**
NETWORK Total			**35,039**	**36,442**	**35,741**	**35,820**	**36,109**	**36,355**	**36,232**	**491**
INTERTIE	MONTANA INTERTIE LONG TERM	IM LONG TERM FIRM	16	16	16	16	16	16	16	0
	MONTANA INTERTIE LONG TERM Total		**16**	**16**	**16**	**16**	**16**	**16**	**16**	**0**
	SOUTHERN INTERTIE LONG TERM	IS LONG TERM FIRM	6,025	6,025	6,025	6,023	6,023	6,027	6,025	0
	SOUTHERN INTERTIE LONG TERM Total		**6,025**	**6,025**	**6,025**	**6,023**	**6,023**	**6,027**	**6,025**	**0**
	SOUTHERN INTERTIE SHORT TERM	IS DAILY FIRM DAYS 1-5	1	1	1	1	1	1	1	0
		IS DAILY FIRM DAYS 6+	2	2	2	2	2	2	2	0
		IS HOURLY NONFIRM	54	54	54	50	52	50	51	(3)
	SOUTHERN INTERTIE SHORT TERM Total		**57**	**57**	**57**	**53**	**55**	**54**	**54**	**(3)**
INTERTIE Total			**6,098**	**6,098**	**6,098**	**6,093**	**6,094**	**6,096**	**6,095**	**(3)**
DELIVERY	UTILITY DELIVERY	UTILITY DELIVERY CHARGE	163	163	163	155	156	157	156	(7)
	UTILITY DELIVERY Total		**163**	**163**	**163**	**155**	**156**	**157**	**156**	**(7)**
DELIVERY Total			**163**	**163**	**163**	**155**	**156**	**157**	**156**	**(7)**

Transmission Preliminary Revenue Credits

	BP-20 FINAL		BP-22 INITIAL PROPOSAL		BP-22 - BP20
PRODUCT CATEGORY	2020	2021	2022	2023	AVG $
DSI DELIVERY	1,914,696	1,914,696	1,921,848	1,921,848	7,152
FIBER - OTHER REIMBURSABLE REV	1,578,025	1,583,150	1,425,192	1,416,257	(159,863)
FIBER- OTHER REVENUE	9,088,004	11,949,725	6,562,523	6,544,013	(3,965,596)
WIRELESS/PCS - OTHER REVENUE	5,966,466	5,966,466	6,244,373	6,244,373	277,907
WIRELESS/PCS - REIMBURSABLE	4,032,000	4,032,000	4,032,000	4,032,000	0
AC-PNW PSW INTERTIE	1,999,824	1,999,824	2,209,800	2,209,800	209,976
GENERATION INTEGRATION	13,577,000	13,671,000	13,623,996	13,623,996	(4)
LAND LEASES AND SALES	295,303	295,303	295,303	295,303	0
MISC SERVICES-LOSS-EXCH-AIR	42,912	42,912	42,912	42,912	0
NFP - DEPR PNW PSW INTERTIE	2,301,000	2,301,000	3,488,076	3,488,076	1,187,076
OPERATIONS & MAINTENANCE	657,752	657,752	565,112	565,112	(92,640)
OTHER MISC LEASES	104,859	104,859	104,859	104,859	0
OTHER REVENUE SOURCES	5,309,386	5,309,386	5,316,814	5,316,814	7,428
REMEDIAL ACTION SCHEME	56,268	56,268	38,112	38,112	(18,156)
RESERVATION FEES	1,801,975	257,425	413,910	413,910	(615,790)
TOWNSEND-GARRISON TRANS	12,420,708	12,420,708	12,420,708	12,420,708	0
TRANSMISSION SHARE OF IPP	245,697	245,697	245,697	245,697	0
USE OF FACILITIES	4,917,888	4,917,888	4,623,492	4,623,492	**(294,396)**
	66,309,763	**67,726,059**	**63,574,726**	**63,547,281**	**(3,456,907)**

Appendix: Sales and Revenues Forecast

Preliminary Sales by Month FY 2021

Product Group	Product Category	Product Name	1	2	3	4	5	6	7	8	9	10	11	12
NETWORK	FORMULA POWER TRANSMISSION	FPT 1YR LONG TERM FIRM	804	804	804	804	804	804	804	804	804	804	804	804
		FPT 3YR LONG TERM FIRM	72	84	95	90	81	81	74	69	62	69	69	68
	FORMULA POWER TRANSMISSION Total		**875**	**888**	**899**	**894**	**885**	**885**	**878**	**873**	**865**	**873**	**873**	**871**
	NETWORK INTEGRATION	NT SERVICE CHARGE	5,638	6,903	7,829	7,693	7,300	6,554	5,794	5,485	5,938	6,406	6,234	5,684
		NT SHORT DISTANCE DISCOUNT	-119	-127	-125	-135	-91	-93	-88	-50	-85	-112	-124	-134
	NETWORK INTEGRATION Total		**5,520**	**6,776**	**7,705**	**7,558**	**7,208**	**6,461**	**5,705**	**5,435**	**5,853**	**6,294**	**6,110**	**5,550**
	POINT-TO-POINT LONG TERM	PTP LONG TERM FIRM	25,466	25,472	25,539	26,755	26,775	26,774	26,774	26,484	26,521	26,521	26,521	26,521
		PTP LTF CANADIAN ENTITLEMENT	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120
		PTP LTF CONDITIONAL FIRM	71	71	71	121	121	121	121	121	129	129	129	129
		PTP SHORT DISTANCE DISCOUNT	-290	-290	-290	-290	-290	-290	-290	-290	-290	-290	-290	-290
	POINT-TO-POINT LONG TERM Total		**26,367**	**26,373**	**26,440**	**27,706**	**27,726**	**27,725**	**27,725**	**27,435**	**27,480**	**27,480**	**27,480**	**27,480**
	POINT-TO-POINT SHORT TERM	PTP DAILY FIRM DAYS 1-5	0	0	19	243	305	170	753	663	780	396	28	0
		PTP DAILY FIRM DAYS 6+	0	0	609	596	595	289	1,597	2,146	2,066	527	466	344
		PTP HOURLY NONFIRM	203	472	184	331	287	133	504	322	374	217	30	45
	POINT-TO-POINT SHORT TERM Total		**203**	**472**	**811**	**1,170**	**1,187**	**592**	**2,854**	**3,131**	**3,220**	**1,140**	**523**	**389**
NETWORK Total			**32,965**	**34,508**	**35,854**	**37,327**	**37,006**	**35,663**	**37,162**	**36,874**	**37,418**	**35,786**	**34,985**	**34,290**
INTERTIE	MONTANA INTERTIE LONG TERM	IM LONG TERM FIRM	16	16	16	16	16	16	16	16	16	16	16	16
	MONTANA INTERTIE LONG TERM Total		**16**	**16**	**16**	**16**	**16**	**16**	**16**	**16**	**16**	**16**	**16**	**16**
	SOUTHERN INTERTIE LONG TERM	IS LONG TERM FIRM	6,025	6,025	6,025	6,025	6,025	6,022	6,022	6,022	6,022	6,022	6,022	6,022
	SOUTHERN INTERTIE LONG TERM Total		**6,025**	**6,025**	**6,025**	**6,025**	**6,025**	**6,022**	**6,022**	**6,022**	**6,022**	**6,022**	**6,022**	**6,022**
	SOUTHERN INTERTIE SHORT TERM	IS DAILY FIRM DAYS 1-5	0	0	2	1	0	1	1	1	1	1	0	0
		IS DAILY FIRM DAYS 6+	3	3	1	2	3	2	3	2	2	2	3	3
		IS HOURLY NONFIRM	49	51	51	53	51	50	47	53	47	56	42	51
	SOUTHERN INTERTIE SHORT TERM Total		**53**	**54**	**54**	**56**	**55**	**54**	**50**	**56**	**50**	**59**	**46**	**54**
INTERTIE Total			**6,094**	**6,095**	**6,095**	**6,097**	**6,096**	**6,092**	**6,088**	**6,094**	**6,088**	**6,097**	**6,084**	**6,092**
DELIVERY	UTILITY DELIVERY	UTILITY DELIVERY CHARGE	133	167	193	185	176	160	141	128	139	155	150	131
	UTILITY DELIVERY Total		**133**	**167**	**193**	**185**	**176**	**160**	**141**	**128**	**139**	**155**	**150**	**131**
DELIVERY Total			**133**	**167**	**193**	**185**	**176**	**160**	**141**	**128**	**139**	**155**	**150**	**131**

Preliminary Sales by Month FY 2022

Product Group	Product Category	Product Name	1	2	3	4	5	6	7	8	9	10	11	12
NETWORK	FORMULA POWER TRANSMISSION	FPT 1YR LONG TERM FIRM	804	804	804	804	804	804	804	804	804	804	804	804
		FPT 3YR LONG TERM FIRM	72	84	95	90	81	81	74	69	62	69	69	68
	FORMULA POWER TRANSMISSION Total		**875**	**888**	**899**	**894**	**885**	**885**	**878**	**873**	**865**	**873**	**873**	**871**
	NETWORK INTEGRATION	NT SERVICE CHARGE	5,730	7,501	8,575	8,787	8,347	7,461	6,342	5,905	6,659	7,135	6,968	6,139
		NT SHORT DISTANCE DISCOUNT	-119	-127	-125	-135	-91	-93	-88	-50	-85	-112	-124	-134
	NETWORK INTEGRATION Total		**5,611**	**7,373**	**8,450**	**8,652**	**8,255**	**7,368**	**6,253**	**5,855**	**6,574**	**7,023**	**6,844**	**6,005**
	POINT-TO-POINT LONG TERM	PTP LONG TERM FIRM	25,815	25,815	25,733	25,834	26,038	26,058	26,058	26,058	26,058	26,058	26,058	26,055
		PTP LTF CANADIAN ENTITLEMENT	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120
		PTP LTF CONDITIONAL FIRM	129	129	129	129	129	129	129	114	114	114	114	114
		PTP SHORT DISTANCE DISCOUNT	-290	-290	-290	-290	-290	-290	-290	-290	-290	-290	-290	-290
	POINT-TO-POINT LONG TERM Total		**26,774**	**26,774**	**26,692**	**26,793**	**26,997**	**27,017**	**27,017**	**27,002**	**27,002**	**27,002**	**27,002**	**26,999**
	POINT-TO-POINT SHORT TERM	PTP DAILY FIRM DAYS 1-5	0	0	13	127	173	369	176	642	915	739	47	0
		PTP DAILY FIRM DAYS 6+	0	0	631	340	396	627	372	2,076	2,422	984	796	512
		PTP HOURLY NONFIRM	315	422	183	204	220	289	117	312	478	406	50	67
	POINT-TO-POINT SHORT TERM Total		**315**	**422**	**826**	**671**	**789**	**1,285**	**664**	**3,029**	**3,816**	**2,128**	**894**	**578**
NETWORK Total			**33,575**	**35,457**	**36,867**	**37,009**	**36,926**	**36,555**	**34,812**	**36,759**	**38,256**	**37,026**	**35,612**	**34,454**
INTERTIE	MONTANA INTERTIE LONG TERM	IM LONG TERM FIRM	16	16	16	16	16	16	16	16	16	16	16	16
	MONTANA INTERTIE LONG TERM Total		**16**	**16**	**16**	**16**	**16**	**16**	**16**	**16**	**16**	**16**	**16**	**16**
	SOUTHERN INTERTIE LONG TERM	IS LONG TERM FIRM	6,023	6,023	6,023	6,023	6,023	6,023	6,023	6,023	6,023	6,023	6,023	6,023
	SOUTHERN INTERTIE LONG TERM Total		**6,023**	**6,023**	**6,023**	**6,023**	**6,023**	**6,023**	**6,023**	**6,023**	**6,023**	**6,023**	**6,023**	**6,023**
	SOUTHERN INTERTIE SHORT TERM	IS DAILY FIRM DAYS 1-5	0	0	2	1	0	1	1	1	1	1	0	0
		IS DAILY FIRM DAYS 6+	3	3	1	2	3	2	3	2	2	2	3	3
		IS HOURLY NONFIRM	51	51	51	54	52	51	44	56	53	59	45	53
	SOUTHERN INTERTIE SHORT TERM Total		**54**	**54**	**54**	**57**	**55**	**54**	**47**	**59**	**56**	**62**	**49**	**56**
INTERTIE Total			**6,094**	**6,093**	**6,094**	**6,096**	**6,094**	**6,093**	**6,086**	**6,098**	**6,095**	**6,101**	**6,088**	**6,095**
DELIVERY	UTILITY DELIVERY	UTILITY DELIVERY CHARGE	134	168	194	186	177	161	142	128	140	156	151	132
	UTILITY DELIVERY Total		**134**	**168**	**194**	**186**	**177**	**161**	**142**	**128**	**140**	**156**	**151**	**132**
DELIVERY Total			**134**	**168**	**194**	**186**	**177**	**161**	**142**	**128**	**140**	**156**	**151**	**132**

Preliminary Sales by Month FY 2023

Product Group	Product Category	Product Name	1	2	3	4	5	6	7	8	9	10	11	12
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		FPT 3YR LONG TERM FIRM	72	84	95	90	81	81	74	69	62	69	69	68
	FORMULA POWER TRANSMISSION Total		**875**	**888**	**899**	**894**	**885**	**885**	**878**	**873**	**865**	**873**	**873**	**871**
	NETWORK INTEGRATION	NT SERVICE CHARGE	6,284	7,634	8,745	8,861	8,416	7,529	6,366	5,964	6,720	7,200	7,034	6,204
		NT SHORT DISTANCE DISCOUNT	-119	-127	-125	-135	-91	-93	-88	-50	-85	-112	-124	-134
	NETWORK INTEGRATION Total		**6,165**	**7,507**	**8,620**	**8,726**	**8,325**	**7,436**	**6,278**	**5,914**	**6,635**	**7,088**	**6,909**	**6,070**
	POINT-TO-POINT LONG TERM	PTP LONG TERM FIRM	25,954	25,894	26,094	26,149	26,149	26,225	26,225	26,225	26,225	26,210	26,210	26,210
		PTP LTF CANADIAN ENTITLEMENT	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120
		PTP LTF CONDITIONAL FIRM	114	114	114	114	114	114	114	114	114	114	114	114
		PTP SHORT DISTANCE DISCOUNT	-290	-290	-290	-290	-290	-290	-290	-290	-290	-290	-290	-290
	POINT-TO-POINT LONG TERM Total		**26,898**	**26,838**	**27,038**	**27,093**	**27,093**	**27,169**	**27,169**	**27,169**	**27,169**	**27,154**	**27,154**	**27,154**
	POINT-TO-POINT SHORT TERM	PTP DAILY FIRM DAYS 1-5	0	0	18	200	343	125	724	647	808	404	24	0
		PTP DAILY FIRM DAYS 6+	0	0	499	490	632	211	1,536	2,093	2,138	538	395	221
		PTP HOURLY NONFIRM	223	356	153	272	286	97	484	314	422	222	25	29
	POINT-TO-POINT SHORT TERM Total		**223**	**356**	**670**	**962**	**1,262**	**433**	**2,745**	**3,054**	**3,368**	**1,163**	**443**	**249**
NETWORK Total			**34,161**	**35,588**	**37,227**	**37,675**	**37,564**	**35,923**	**37,069**	**37,010**	**38,037**	**36,277**	**35,379**	**34,345**
INTERTIE	MONTANA INTERTIE LONG TERM	IM LONG TERM FIRM	16	16	16	16	16	16	16	16	16	16	16	16
	MONTANA INTERTIE LONG TERM Total		**16**	**16**	**16**	**16**	**16**	**16**	**16**	**16**	**16**	**16**	**16**	**16**
	SOUTHERN INTERTIE LONG TERM	IS LONG TERM FIRM	6,023	6,023	6,023	6,028	6,028	6,028	6,028	6,028	6,028	6,028	6,028	6,028
	SOUTHERN INTERTIE LONG TERM Total		**6,023**	**6,023**	**6,023**	**6,028**	**6,028**	**6,028**	**6,028**	**6,028**	**6,028**	**6,028**	**6,028**	**6,028**
	SOUTHERN INTERTIE SHORT TERM	IS DAILY FIRM DAYS 1-5	0	0	2	1	0	1	1	1	1	1	0	0
		IS DAILY FIRM DAYS 6+	3	3	1	2	3	2	3	2	2	2	3	3
		IS HOURLY NONFIRM	50	49	49	55	53	49	45	55	51	57	41	48
	SOUTHERN INTERTIE SHORT TERM Total		**53**	**53**	**52**	**58**	**56**	**53**	**49**	**58**	**55**	**60**	**45**	**51**
INTERTIE Total			**6,092**	**6,092**	**6,091**	**6,102**	**6,100**	**6,097**	**6,093**	**6,102**	**6,099**	**6,104**	**6,089**	**6,096**
DELIVERY	UTILITY DELIVERY	UTILITY DELIVERY CHARGE	135	169	195	187	178	162	143	129	141	157	152	132
	UTILITY DELIVERY Total		**135**	**169**	**195**	**187**	**178**	**162**	**143**	**129**	**141**	**157**	**152**	**132**
DELIVERY Total			**135**	**169**	**195**	**187**	**178**	**162**	**143**	**129**	**141**	**157**	**152**	**132**

Transmission Loads

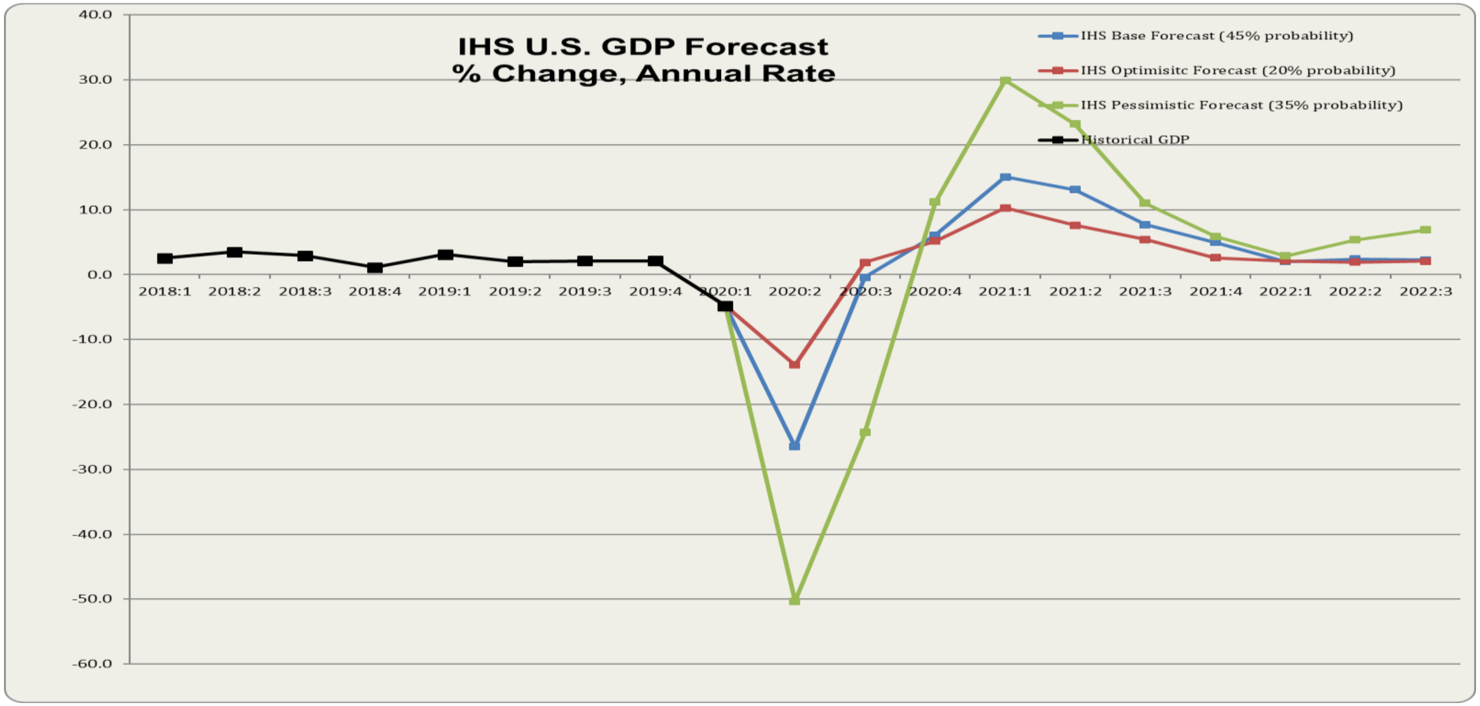
Load Forecasting Process

- Annual forecast updates are developed within the Agency Load Forecasting tool (ALF)
- Each customer/POD/Bus element is individually forecasted
  - Statistical based regression models using up to 10 years of historical data
  - All energy and non-coincidental models are independent models
  - All coincidental peaks are dependent on non-coincident peak model using historical factors
- Normal weather continues to be a 34 year average value
- Continuation of trend is expected augmented with known changes

Load Forecasting Process, continued

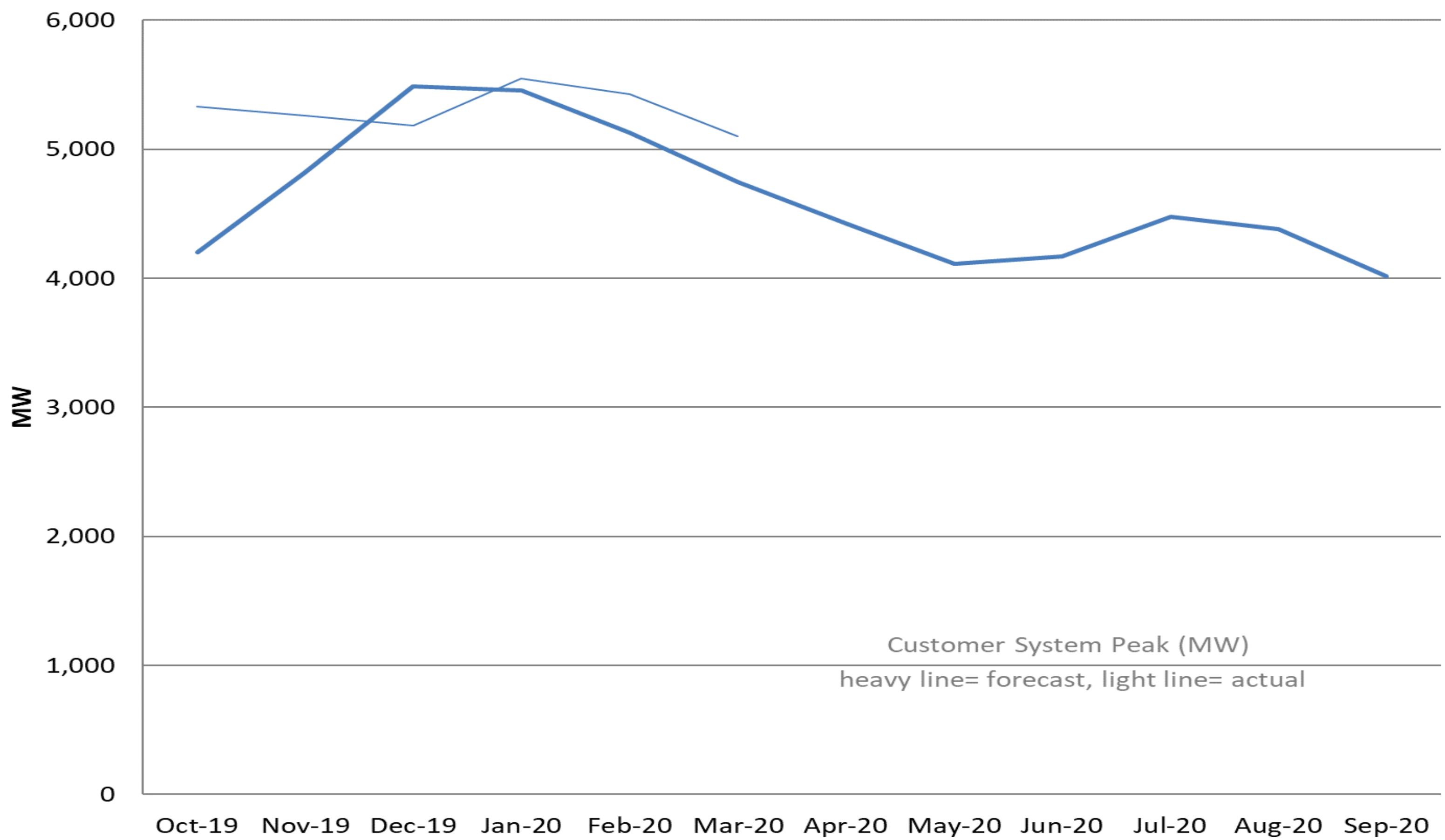
- Preliminary forecast reviewed by Customer, and other interested parties for
  - Regional economic conditions
    - Migration patterns
    - Individual industrial plant activity
    - Changing consumer behavior
  - Demographic conditions
    - Birth and Death Rates
    - Age and Gender
  - Off trend growth is added to trend
  - Off trend examples
    - New large industrial or commercial loads
    - New large subdivision additions

Current Forecasted Economic Conditions



- Negative GDP growth is expected for the nation
- Regional unemployment has increased significantly
- Load continues to remain flat
- World economic concerns continue

Current Models - Peaks



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

Forecasted Agency Loads

	Mwa				
	2020	2021	2022	2023	2024
Prior Forecast (April 2018)	9,631	9,944	10,137	10,435	10,348
Current Forecast (April 2019)	9,605	9,741	9,863	9,952	10,017
change	-26	-203	-274	-483	-331
% change	-0.3%	-2.0%	-2.7%	-4.6%	-3.2%

- ~30% of the customers increased forecast over last year levels, ~ 40% reduced forecast, ~ 30% no change
- Average change about 2 aMW per customer

- Bulk of changes are the results of anticipated specific large customer adjustments with most of the change coming from a few customers.

- We continue to monitor the economic conditions and how likely they are to reach out to 2022.

Interconnection Credits
(GI and Non-GI)

Interconnection Credit Background

- A customer may request that BPA advance the completion of Network Upgrades that are necessary to enable the customer's project and that would otherwise not be completed in time to support the project's timeline, provided that customer commits to advance any associated expediting costs. This construct results in transmission credits, for any expediting costs paid.

- Interconnection deposits are considered advanced payment of future revenues. The deposited funds are used for construction or upgrades to network facilities. Advanced funds earn interest from the day of deposit and for the duration of the repayment period. The customer receives a transmission credit until the deposit is repaid or forfeit at the end of the repayment period.

- The net effect of Interconnection Credits 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.

Interconnection Credits Effect on Revenue Requirement =

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

- Generally, credits are repaid in a shorter timeframe than the useful life of the assets. Credits tend to be repaid in 5-12 years while the assets may have much longer service lives.

Credit Policies

- Interconnection credits are managed under two policies:
  - Generator Interconnection (see GI Transmission Credits Business Practice)
    - SGI/LGI
  - Non-GI (see Transmission Credits for Non-GI Transmission Upgrades Business Practice)
    - LLI
- Each policy has its own unique requirements that must be considered in developing the forecast.

GI vs. Non-GI Credit Plans

	GI	Non-GI
Repayment Rate	Dollar-for-dollar at current rate for reserved Transmission Service (Method 1) or Generator Nameplate * Capacity Factor * Current Rate (Method 2)	Metered Incremental POD Demand per Credit Agreement (NT), or Eligible Incremental Transmission Service (PTP)
Repayment Term	20 Year	
Interest Rate	USD Government Agency BVAL Curve	
Start Date	Transmission Service Commencement Date (Method 1) or Commercial Operation Date in LGIA/SGIA (Method 2)	Energization Date of Network Upgrades
20-Year Balance	Cash refund (Tariff Requirement)	Forfeit

Transmission Credits Rate Case Forecast Process

- The Generation Interconnection (GI) and Line and Load Interconnection (LLI) Queues are assessed to determine which projects have a high likelihood to be completed prior to or during the upcoming rate period.
- To the extent possible, projects are tied to a request(s) in the Transmission Queue to forecast sales eligible to receive Transmission Credits.
- When a request in the queue cannot be tied to a request(s) in the Transmission Queue, a percentage of the nameplate is used to forecast the sales eligible to receive credits based on historical models.
    - 30% - Year 1
    - 50% - Year 2
    - 70% - Year 3
- For NT LLI requests, a load shape is applied to the forecast for the project.
- The dollar value of the Transmission Credits is forecasted based upon historical transmission credit averages, TSRs at the LT PTP rate, or projected new generation/load.
- Interest expense is calculated based on the applicable interest rate at the time of deposit or, for forecast deposits, based on the average interest rates of the most recent 12-month period.

BP-22 Transmission Credit Preliminary Forecast Results

- BPA currently holds $167 million in funds advanced for Network Upgrades. Of this total:
  - $125 million is currently in the repayment period, with customers actively receiving Transmission Credits
  - $42 million is pending project completion and are accruing interest.
- For the BP-22 rate period, BPA is forecasting approximately $45 million in additional funds to be advanced for Network Upgrades for continuing and future interconnection projects.
- The average transmission credit is $26.7 million per year in FY 22-23.
- The average interest expense is $4.5 million per year in FY 22-23.

BP-22 Transmission Credit and Interest Preliminary Forecast

The following slide shows the credit and interest forecast for GI and LLI projects in two categories:

1. Projects where customers are currently receiving Transmission Credits
   - GI – rows 1-8
   - LLI – rows 21-27
2. Projects where the credit repayment forecast is based on TSRs, Generator Nameplate or load forecast
   - GI – rows 9-20
   - LLI – rows 28-35

Projects highlighted in green are currently in their repayment period; projects in white are not yet in their repayment period and deposits are earning interest only.

BP-22 GI & LLI Credit and Interest Forecast

#	Request	Tx Credit Balance as of 6/1/2020	Upgrade Deposits During FY21-23	Forecasted Credits ($000) FY 2021	Forecasted Credits ($000) FY 2022	Forecasted Credits ($000) FY 2023	Forecasted Interest ($000) FY 2021	Forecasted Interest ($000) FY 2022	Forecasted Interest ($000) FY 2023
1	GI Request 1	$ 1,088	$ -	$ 795	$ -	$ -	$ 15	$ -	$ -
2	GI Request 2	$ 57,676	$ -	$ 6,223	$ 6,223	$ 7,094	$ 1,926	$ 1,770	$ 1,603
3	GI Request 3	$ 1,854	$ -	$ 954	$ 664	$ -	$ 41	$ 8	$ -
4	GI Request 4	$ 9,949	$ -	$ 705	$ 705	$ 705	$ 360	$ 347	$ 334
5	GI Request 5	$ 2,660	$ -	$ 1,075	$ -	$ -	$ 2	$ -	$ -
6	GI Request 6	$ 2,092	$ -	$ 129	$ 129	$ 129	$ 66	$ 64	$ 62
7	GI Request 7	$ 1,397	$ -	$ 129	$ 129	$ 129	$ 41	$ 39	$ 36
8	GI Request 8	$ 1,452	$ -	$ 184	$ 184	$ 184	$ 42	$ 38	$ 33
9	GI Request 9	$ 14,380	$ -	$ 1,410	$ 2,146	$ 2,575	$ 349	$ 311	$ 256
10	GI Request 10	$ 6,814	$ -	$ 331	$ 552	$ 773	$ 202	$ 195	$ 181
11	GI Request 11	$ 2,809	$ -	$ 276	$ 445	$ 644	$ 65	$ 58	$ 46
12	GI Request 12	$ 1,821	$ 4,829	$ 1,656	$ 2,759	$ 2,586	$ 182	$ 117	$ 23
13	GI Request 13	$ 469	$ 1,047	$ -	$ 101	$ 178	$ 50	$ 50	$ 47
14	GI Request 14	$ 2,172	$ 8,993	$ -	$ 2,223	$ 3,219	$ 196	$ 234	$ 174
15	GI Request 15	$ 3,856	$ -	$ -	$ -	$ 1,012	$ 79	$ 80	$ 72
16	GI Request 16	$ 754	$ 19,000	$ -	$ 1,548	$ 2,477	$ 256	$ 339	$ 308
17	GI Request 17	$ 153	$ 3,147	$ -	$ 375	$ 1,376	$ 40	$ 63	$ 45
18	GI Request 18	$ -	$ 300	$ -	$ -	$ 419	$ 25	$ 56	$ 53
19	GI Request 19	$ -	$ 4,000	$ -	$ 1,012	$ 1,778	$ 62	$ 66	$ 40
20	GI Request 20	$ -	$ 3,988	$ -	$ 110	$ 184	$ 74	$ 74	$ 73
21	LLI Request 1	$ 593	$ -	$ 348	$ 159	$ -	$ 8	$ 0	$ -
22	LLI Request 2	$ 140	$ -	$ 109	$ -	$ -	$ 0	$ -	$ -
23	LLI Request 3	$ 37,892	$ -	$ 1,275	$ 2,022	$ 2,975	$ 681	$ 665	$ 628
24	LLI Request 4	$ 674	$ -	$ 128	$ 204	$ 298	$ 16	$ 12	$ 5
25	LLI Request 5	$ 6,867	$ -	$ 5,531	$ -	$ -	$ 72	$ -	$ -
26	LLI Request 6	$ 534	$ -	$ 154	$ 239	$ 128	$ 11	$ 6	$ 1
27	LLI Request 7	$ 240	$ -	$ 128	$ 82	$ -	$ 4	$ 1	$ -
28	LLI Request 8	$ 771	$ -	$ 533	$ 263	$ -	$ 14	$ 1	$ -
29	LLI Request 9	$ 53	$ -	$ 8	$ 31	$ 18	$ 1	$ 1	$ 0
30	LLI Request 10	$ 53	$ -	$ -	$ -	$ -	$ 17	$ 18	$ 18
31	LLI Request 11	$ 533	$ -	$ 70	$ 113	$ 149	$ 16	$ 14	$ 10
32	LLI Request 12	$ 53	$ -	$ -	$ 70	$ 117	$ 2	$ -	$ -
33	LLI Request 13	$ 81	$ 20	$ -	$ 81	$ 24	$ 2	$ 1	$ 0
34	LLI Request 14	$ 6,361	$ -	$ -	$ 478	$ 985	$ 215	$ 215	$ 197
35	LLI Request 15	$ 697	$ -	$ 48	$ 90	$ 128	$ 13	$ 12	$ 10
	Total Forecast	**$ 166,938**	**$ 45,325**	**$ 22,198**	**$ 23,135**	**$ 30,282**	**$ 5,145**	**$ 4,855**	**$ 4,252**

Appendix

Non-Cash Revenues: Effect on Revenue Requirements

- A basic premise for setting rates is that Revenues from Proposed Rates must be greater than or equal to the Revenue Requirement, as measured on both an accrual and cash perspective.
- If there will be non-cash 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

Rate Design – EIM Charge Code Cost Allocation Implementation

Steps 1-4

Charge Code Implementation

- Policy Direction Summary
- Contextual Background
- Sub-Allocation Methodology Alternatives
- Unallocated Cost Recovery Alternatives
- Scenarios for EIM

Plan for Today

Process Framework

Phases One and Two: Approach and Evaluation	Phase Three: Proposal Development
Step 1: Introduction & Education Step 2: Description of the Issue Step 3: Analyze the Issue Step 4: Discuss Alternatives	Step 5: Customer Feedback Step 6: Staff Proposal
Today's Workshop	August 25-26 Workshop

Policy Direction for BP-22 Initial Proposal

- BPA staff propose to begin the BP-22 Initial Proposal development pursuing a phased in charge code allocation approach.
- For BP-22, staff propose to begin with BPA-defined partial sub-allocation.
- This presentation outlines sub-allocation methodology alternatives for codes that staff propose to sub-allocate for BP-22, as well as discussing cost recovery alternatives for unallocated codes.

Staff Proposed Phased In Approach

BP-22

Begin Charge Code Allocation and Modify Existing Rate Structures (as needed)

BP-24

Leverage Preliminary Data to Modify Charge Code Allocation and/or Rate Structures (as needed)

BP-26

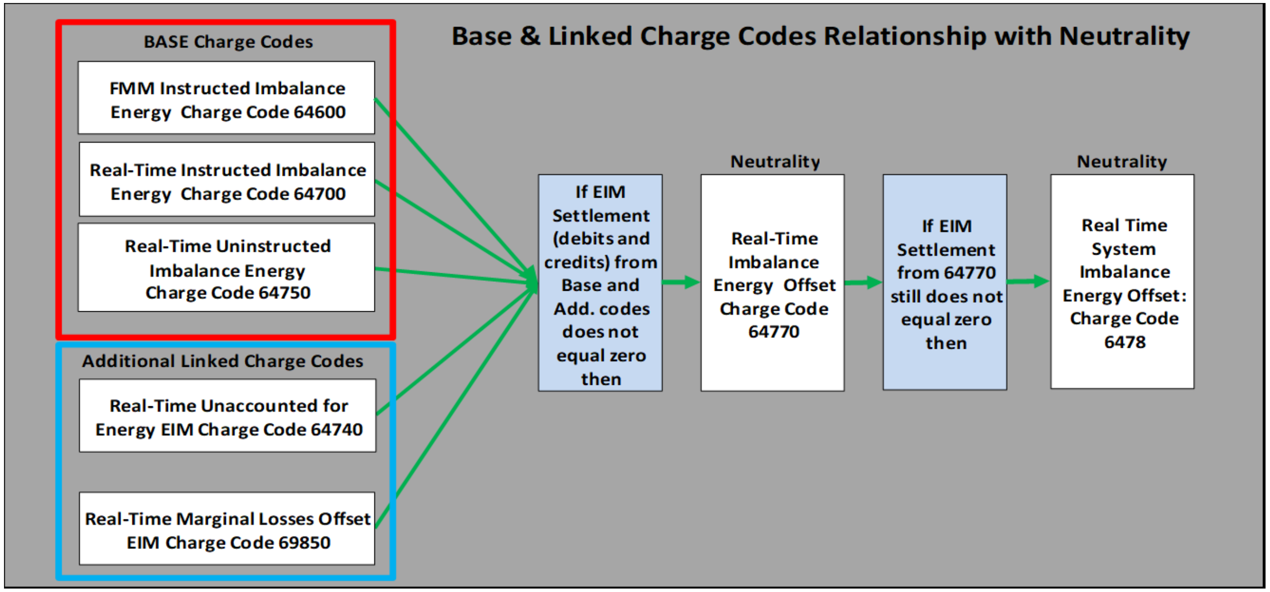
Utilize Two Years of Data to Complete Refinement of Charge Code Allocation and/or Rate Structures (as needed)

Approach implementation is subject to change by rate period, given factors such as information availability and market changes.

Context: FERC-Approved Methods

- There is no *pro forma* method for allocating the various charge codes.
- While most EIM entities have followed similar cost allocation methodologies, that is not always the case.
- For example, PGE sub-allocates the real time cost of marginal loss offset charges based on measured demand, but PAC does not sub-allocate these charges.
- While FERC-approved methods are considered as a starting point, there may be rationale to modify methods to align with cost-causation.

Context: Neutrality Codes



- Neutrality codes are designed to financially settle the CAISO EIM market and are connected to the base EIM charge codes.
- EIM entities typically sub-allocate these codes through measured demand, given the market design complexities.
- Sub-allocating neutrality codes at the time of the settlement works to align the charges/credits with the behaviors within the market.
- Alternatives for BPA to sub-allocate neutrality codes will be discussed later in this presentation.

SUB-ALLOCATED CODES

Staff Proposed Charge Codes for BP-22 Sub-Allocation

Base Codes	Neutrality Codes + Congestion Offset Code	Scheduling Penalty Codes

Charge Codes Excluded from Proposed Sub-Allocation for BP-22:

Bid Cost Recovery Codes
Flexible Ramp Codes
Grid Management Charge Codes
Enforcement Protocol (EP) Penalty Code
Administrative Codes

Sub-Allocation Methods Considered

- Direct Assignment
- Measured Demand vs. Metered Demand vs. Imbalance
- Magnitude vs. Direction vs. Imbalance Use
- See Appendix for Descriptions

Base Codes

Code Number	Description	FERC Allocation Method
64750	Uninstructed Imbalance Energy (Schedule 4 and Schedule 9)	Direct Assignment
64600	FMM Instructed Imbalance Energy (Energy Imbalance)	Direct Assignment
64700	Real-Time Instructed Imbalance Energy (Energy Imbalance)	Direct Assignment

RECOMMENDATION: Direct Assignment for All Base Codes

Rationale: Aligned with cost-causation, consistent with other entities/approved approach

Definition: Direct allocation of the charges and credits to customers based on customer behavior in the CAISO EIM. The charges and credits are based on granular customer level detail behind the CAISO settlements to the EESC.

Neutrality Codes

Code Number	Description	FERC Allocation Method
64770	Real Time Imbalance Energy Offset EIM	Measured Demand
64740	Real Time Unaccounted for EIM Energy Settlement	Measured Demand
69850	Real Time Marginal Losses Offset EIM	Measured Demand
6478	Real Time Imbalance Energy Offset	Measured Demand
67740	Real Time Congestion Offset EIM	Measured Demand

RECOMMENDED OPTIONS:
Measured Demand by Magnitude or Imbalance by Magnitude for ALL Codes

Rationale:
- **Measured Demand by Magnitude:** Consistent with other entities/approved approach, mirrors CAISO BAA allocation, other methods not recommended did not provide additional cost-causation alignment
- **Imbalance by Magnitude:** Costs are allocated to customers with the largest imbalances, because they are the most active participants in the EIM market

Definition:
- **Measured Demand by Magnitude:** Takes each customer's load ratio share, measured as the customer's Measured Demand (Metered Demand + Export Schedules) divided by the Total BAA Measured Demand multiplied by the amount billed to the BAA under each neutrality charge code. The Metered Demand for each customer is their metered load, including losses.
- **Imbalance by Magnitude:** Takes each customer's imbalance, regardless of direction, divided by the absolute value of the total customer imbalance multiplied by the amount billed to the BAA under each neutrality charge code. Those customers without any imbalance are not allocated any costs.

Over/Under Scheduling Codes

Code Number	Description	FERC Allocation Method
6045	Under/Over Schedule Load Charge	Imbalance by Direction
6046	Under/Over Schedule Load Allocation	Metered Demand by Magnitude

RECOMMENDATION (6045): Imbalance by Direction

Rationale: Allocates costs only to those that caused the penalty

Definition: Takes each customer's imbalance in the same direction as the BAA imbalance, divided the sum of the customer imbalances in the same direction as the BAA multiplied by the amount billed to the BAA under code 6045

RECOMMENDED OPTIONS (6046*):

Metered Demand by Magnitude or Metered Demand by Magnitude with Imbalance Threshold

Rationale:

- **Metered Demand by Magnitude:** Mirrors CAISO BAA Allocation, consistent with most other EIM entities, allows credits to be allocated based on the size of each customer's overall demand within the BAA.
- **Metered Demand by Magnitude with Imbalance Threshold:** In addition to rationale above, incentivizes individual customer scheduling accuracy in order to receive share of credit

Definition:

- **Metered Demand by Magnitude:** Takes each customer's load ratio share, measured as the customer's Metered Demand (metered load, including losses) divided by the Total BAA Metered Demand multiplied by the amount credited to the BAA under code 6046
- **Metered Demand by Magnitude with Imbalance Threshold:** Same as above, but only allocates to those customers with imbalance at or below a predetermined imbalance tolerance (e.g. within 5-percent of schedule)

**Note that code 6046 is a credit to EIM entities on days in which they did not receive any penalty charges associated with code 6045, but other EIM entities did*

Examples for Neutrality & Over/Under Scheduling

	LSE 1	LSE 2	LSE 3	LSE 4	Total
Schedules (Internal)	500	1000	2000	1000	4500
Export Schedules	600	0	0	0	600
Metered Demand	550	950	2010	1000	4510
Measured Demand	1150	950	2010	1000	5110
Imbalance	+50	-50	+10	0	+10

- Measured Demand Magnitude
  - Total measured demand = 1150 + 950 + 2010 + 1000 = 5510
  - LSE1 = X *1150/5110 = X * 22%
  - LSE2 = X * 950/5110 = X * 19%
  - LSE3 = X * 2010/5110 = X * 39%
  - LSE4 = X * 1000/5110 = X * 21%

- Imbalance Magnitude
  - Total absolute imbalance = abs(+50) + abs(-50) + abs(10) + abs(0) = 110
  - LSE1 = X * abs(+50)/110 = X * 45%
  - LSE2 = X * abs(-50)/110 = X * 45%
  - LSE3 = X * abs(+10)/110 = X * 9%
  - LSE4 = 0

- Imbalance by Direction
  - Total imbalance in applicable direction = +50 + (-50) + (10) + (0) = 60
  - LSE1 = X * 50/60 = X * 83%
  - LSE2 = 0
  - LSE3 = X * 10/60 = X * 17%
  - LSE4 = 0

- Metered Demand Magnitude
  - Total metered demand = 550 + 950 + 2010 + 1000 = 4510
  - LSE1 = X * 550/4510 = X * 12%
  - LSE 2 = X * 950/4510 = X * 21%
  - LSE 3 = X * 2010/4510 = X * 45%
  - LSE 4 = X * 1000/4510 = X * 22%

  (Additionally, BPA could elect to only allocate credits to those customers below a certain imbalance threshold)

Note: Assume X is the charge or credit received from the CAISO

UNALLOCATED CODES

Rationale for Unallocated Codes

Administrative

- Not directly tied to customer behavior
- Some fees could be forecast
- Some codes would not be forecast (e.g. penalty fees or rarely used administrative codes)

Flexible Ramping

- EESCs are billed costs to fund resources to address future interval forecast ramp needs (interchange schedule ramps, change in net load forecast) and uncertainty (net load forecast error).
- Payments to resources respects the opportunity cost of awarding flexible ramping, so prices are marginal or the delta between resource's bid and LMP.

Real Time Bid Cost Recovery

- Recovers daily "Shortfalls" (net non-zero positive amounts) for units dispatched in the RTM.
- Charges to the EESC are based on non-zero positive amounts for units within the BAA and the BAA's pro-rata share of EIM transfers in.

Unallocated charge codes do not impact financial settlement chains of proposed set of sub-allocated charge codes. While these codes are not primary drivers of customer behavior in the EIM, they will be further reviewed as part of phased-in approach for BP-24.

Forecastability

CC #	Charge Code Name
701	Forecasting Service Fee
1592	EP Penalty Allocation Payment
2999	Default Invoice Interest Payment
3999	Default Invoice Interest Charge
4564	GMC-EIM Transaction Charge
4575	SMCR -Settlements, Metering, and Client Relations
4989	Daily Rounding Adjustment
4999	Monthly Rounding Adjustment
5024	Invoice Late Payment Penalty
5025	Financial Security Posting (Collateral) Late Payment Penalty

CC #	Charge Code Name
5900	Shortfall Receipt Distribution
5901	Shortfall Allocation Reversal
5910	Shortfall Allocation
5912	Default Loss Allocation
7070	Flexible Ramp Forecast Movement Settlement
7071	Daily Flexible Ramp Up Uncertainty Capacity Settlement
7076	Flexible Ramp Forecast Movement Allocation
7077	Daily Flexible Ramp Up Uncertainty Award Allocation
7078	Monthly Flexible Ramp Up Uncertainty Award Allocation
7081	Daily Flexible Ramp Down Uncertainty Capacity Settlement

CC #	Charge Code Name
7087	Daily Flexible Ramp Down Uncertainty Award Allocation
7088	Monthly Flexible Ramp Down Uncertainty Award Allocation
7989	Invoice Deviation Interest Distribution
7999	Invoice Deviation Interest Allocation
8526	Generator Interconnection Process GIP Forfeited Deposit Allocation
8989	Daily Neutrality Adjustment
8999	Monthly Neutrality Adjustment
66200	Bid Cost Recovery EIM Settlement
66780	Real Time Bid Cost Recovery Allocation EIM

- Codes highlighted in green are ones that BPA would not forecast.
  - One (701) is for a service that BPA already performs at lower cost and plans to request exemption.
  - Two (7071 & 7081) are charged directly to the PRSC.
  - The rest are penalty charges or rarely used administrative charges.
- The remaining codes could, theoretically, be forecast.

Forecastability

- Of the forecastable codes, two are based on fixed monthly charges or posted rates.
- 4575 (Settlements, Metering & Client Relations) is a flat $1,000/month charge.
- 4564 (Grid Management Charge) has two defined rates within it
  - EIM Market Service Charge Rate: $0.0841/MWh (2019 Rate)
  - EIM System Operations Charge Rate: $0.1091/MWh (2019 Rate)
  - The EIM ROD includes estimates of the 5 minute and 15 minute purchases and sales as simulated by E3.
  - The base scenario estimates a total of 791.9 aMW or about 6.9 million MWh.
  - This would produce an annual cost of $1.34 million.
- Total cost of these codes = $1.35 million/year.

Forecastability

- There is limited data on the remaining codes.
- CAISO provided data on the range of monthly costs of other EESCs of our size.

		Maxium Monthly Average	Minimum Monthly Average
7070	Flexible Ramp Forecast Movement Settlement	$49,000.00	($7,000.00)
7076	Flexible Ramp Forecast Movement Allocation	$7,000.00	($13,000.00)
7077	Daily Flexible Ramp Up Uncertainty Award Allocation	$34,000.00	$0.00
7087	Daily Flexible Ramp Down Uncertainty Award Allocation	$8,000.00	($1,000.00)
66780	Real Time Bid Cost Recovery Allocation EIM	$510,000.00	$0.00
	Total	$608,000.00	($21,000.00)

- Continuing to further evaluate these codes to determine the best approach.
- Potential Options Under Review:
  - Risk Assessment – Integrate into Risk Assessment for Transmission
  - Forecast Options:
    - With the uncertainty in ranges, could forecast as zero
    - Could develop a nominal forecast amount around expectations

Allocating Forecasted Costs

- Costs are allocated through the segmented revenue requirement.
- O&M is generally segmented using a 7-year average of actual O&M spending.
- Costs can be directly assigned to a segment (see next slide for segment discussion)

Review and Recommendation

Segments	Considerations
Network	Directly affected by EIM. Consistent with how others segment those costs
Southern Intertie	Consistent with how others segment those costs
Eastern Intertie	Consistent with how others segment those costs
Utility Delivery	Delivery fee for use of facilities
DSI Delivery	Delivery fee for use of facilities
Generation Integration	Charge for Federal generating plants connecting to BPA transmission facilities
Ancillary Services	Specialized fees/rates for specific services

RECOMMENDATION: Segment Costs to the Network, Southern Intertie, and Eastern Intertie

Leverage existing O&M percentages and adjust to distribute costs based on these three segments.

IMBALANCE CHARGE SCENARIOS

Scenario Interpretation

- Each scenario will have a table that looks similar to the table below, which shows:
  - MW numbers:
    - Base Schedule(s) submitted by the base scheduling deadline (highlighted in red)
    - 15-minute market (FMM) expectation (highlighted in orange)
    - 5-minute market (RTD) expectation (highlighted in yellow)
    - Measured Actual (highlighted in green)
  - $
    - FMM Instructed* Imbalance (highlighted in blue)
      - FMM LMP multiplied by the difference between base schedule and FMM expectation
    - RTD Instructed* Imbalance (highlighted in purple)
      - RTD LMP multiplied by the difference between FMM expectation and RTD expectation
    - RTD Uninstructed Imbalance** (highlighted in pink)
      - RTD LMP multiplied by the difference between RTD expectation and measured output

	Non-Participating Resource Generation – Assumed LMP = $40**											
BPA Base Schedule	100											
FMM Market Run Occurs	T-37.5			T-22.5			T-7.5			T+7.5		
	101			101			101			101		
RTD Market Run Occurs	T-2.5	T+2.5	T+7.5	T+12.5	T+17.5	T+22.5	T+27.5	T+32.5	T+37.5	T+42.5	T+47.5	T+52.5
	101	101	101	101	101	101	101	101	101	101	101	101
Metered Actuals	102	102	102	102	102	102	102	102	102	102	102	102
FMM IIE	-$10.00			-$10.00			-$10.00			-$10.00		
RTD IIE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RTD UIE	-$3.33	-$3.33	-$3.33	-$3.33	-$3.33	-$3.33	-$3.33	-$3.33	-$3.33	-$3.33	-$3.33	-$3.33
Total Imbalance	**-$80*** **											

- * Note that while the term “instructed” sounds as though it only refers to dispatches ordered by the market, for NPRs and interchanges, “instructed” really means “was communicated to the market and thus is expected imbalance”
- **In the scenarios that follow, a single LMP was applied to a given resource for all 15-minute and 5-minute intervals. In reality, LMPs in each interval will vary according to the necessary amount of generation, locational congestion, losses, etc. Remember that LAPs, on the other hand, are hourly values.
- *** Note that in these scenarios, a positive value in the table represents a charge and a negative value represents a credit

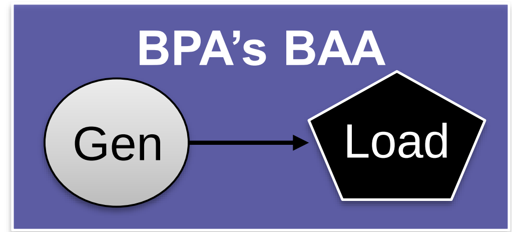
Here’s what it boils down to…

- You can create imbalance if you
  - Operate/consume off of your schedule
    - Generation/Load
  - Change your schedule after T-57
    - Generation and Interchange

Note that the scenarios in this section of the slide deck will deal only with charges and credits due directly to the imbalance energy, and do not include neutrality charges/credits, unallocated charges, or associated penalties.

Scenario 1: Non-federal NPR* Serving Load in BA; Example 1: Perfection (Concept Baseline)

- Resource Sufficiency Timeframe (by T-57):
  - NPR Base schedule = 200 MW
- Pre-Real time:
  - No changes
- Real time:
  - Output = Base Schedule
- After-The-Fact:
  - No Generator Imbalance** Charges

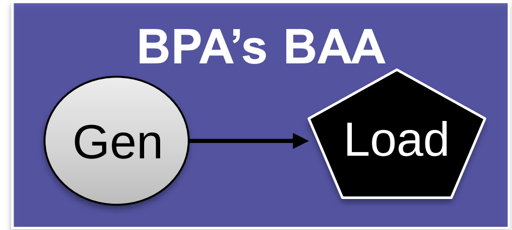


	Non-Participating Resource Generation											
BPA Base Schedule	200											
FMM Market Run Occurs	T-37.5			T-22.5			T-7.5			T+7.5		
	200***			200			200			200***		
RTD Market Run Occurs	T-2.5	T+2.5	T+7.5	T+12.5	T+17.5	T+22.5	T+27.5	T+32.5	T+37.5	T+42.5	T+47.5	T+52.5
	200***	200***	200	200	200	200	200	200	200	200	200***	200***
Metered Actuals	200	200	200	200	200	200	200	200	200	200	200	200
FMM IIE	$ -			$ -			$ -			$ -		
RTD IIE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RTD UIE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Imbalance	**$0**											

* Note that dispatchable NPRs receive no dispatch awards from the EIM, and are expected to stay on their submitted schedule
** Note that the examples in scenario 1 focus on the imbalance exposure of the generator, but do not reflect the imbalance exposure of the load that generator is serving.
*** Note that EIM FMM and RTD runs will reflect standard 20-minute top-of-hour ramping between differing hourly base schedules

Scenario 1: Non-federal NPR Serving Load in BA; Example 2a: Actual Output Below Schedule

- RS Timeframe (by T-57):
  - NPR Base schedule = 200 MW
- Pre-Real time:
  - No changes
- Real time:
  - Output = 10 MW below schedule
- ATF:
  - Gen. Imbalance Charge – UIE (difference between 5-minute market expectation and actual output)

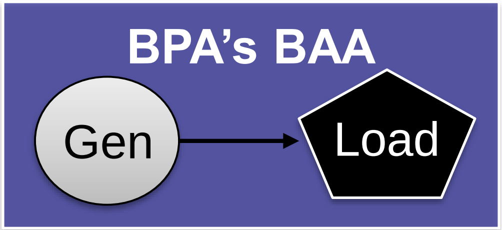


	Non-Participating Resource Generation – Assumed LMP = $40											
BPA Base Schedule	200											
FMM Market Run Occurs	T-37.5			T-22.5			T-7.5			T+7.5		
	200			200			200			200		
RTD Market Run Occurs	T-2.5	T+2.5	T+7.5	T+12.5	T+17.5	T+22.5	T+27.5	T+32.5	T+37.5	T+42.5	T+47.5	T+52.5
	200	200	200	200	200	200	200	200	200	200	200	200
Metered Actuals	190	190	190	190	190	190	190	190	190	190	190	190
FMM IIE	$ -			$ -			$ -			$ -		
RTD IIE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RTD UIE	$33.33	$33.33	$33.33	$33.33	$33.33	$33.33	$33.33	$33.33	$33.33	$33.33	$33.33	$33.33
Total Imbalance	**$400**											

- Footnote 1: Note that, while PRs will receive charges and credits directly from the market operator, and likely will not have their FMM and RTD awards equal to their base schedule, the concept that actual output differing from 5-minute market expectation results in UIE applies to PRs as well as NPRs

Scenario 1: Non-federal NPR Serving Load in BA; Example 3a: Schedule Decrease

- RS Timeframe (by T-57):
  - NPR Base schedule = 200 MW
- Pre-Real time:
  - Decrease to schedule by T-20
- Real time:
  - Equal to T-20 schedule
- ATF:
  - Gen. Imbalance Charge – FMM IIE (difference between BS and FMM run), RTD IIE (difference between FMM run and RTD run)

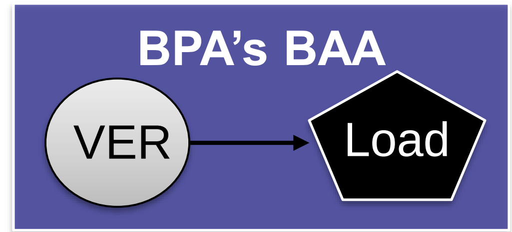


	Non-Participating Resource Generation – Assumed LMP = $40											
BPA Base Schedule	200											
FMM Market Run Occurs	T-37.5			T-22.5			T-7.5			T+7.5		
	200			200			190			190		
RTD Market Run Occurs	T-2.5	T+2.5	T+7.5	T+12.5	T+17.5	T+22.5	T+27.5	T+32.5	T+37.5	T+42.5	T+47.5	T+52.5
	190	190	190	190	190	190	190	190	190	190	190	190
Metered Actuals	190	190	190	190	190	190	190	190	190	190	190	190
FMM IIE	$ -			$ -			$100.00			$100.00		
RTD IIE	$33.33	$33.33	$33.33	$33.33	$33.33	$33.33	$ -	$ -	$ -	$ -	$ -	$ -
RTD UIE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Imbalance	**$400**											

- Footnote 1: Note that, while PRs will receive charges and credits directly from the market operator, and likely will not have their FMM and RTD awards equal to their base schedule, the concept that changes to base schedules result in IIE can apply to PRs as well as NPRs
- Footnote 2: Note that a curtailment to a schedule after T-20 will result in a similar outcome. The main difference is the timing; the adjustment to the schedule will be reflected in the EIM optimization once that information becomes available. For instance, if a curtailment occurs 3 minutes into an hour, the 4 FMM optimizations and the first 2 RTD optimizations have already run and will not reflect that changed schedule, but the subsequent RTD optimizations will

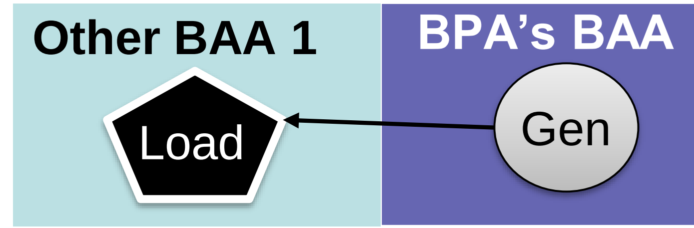
Scenario 1: Non-federal NPR VER Serving Load in BA; Example 4: Differences for VERs

- RS Timeframe (by T-57):
  - NPR Base schedule = 200 MW
- Pre-Real time:
  - No changes
- Real time:
  - CAISO Optimization automatically reflects updated 15- and 5-minute VER forecasts in FMM/RTD schedules
- ATF:
  - Gen. Imbalance Charges and Credits:
    - FMM IIE (difference between T-40 Base Schedule and 15-minute market forecast)
    - RTD IIE (difference between 15-minute market forecast and 5-minute market forecast)
    - RTD UIE (difference between 5-minute market expectation and actual output)



	Non-Participating Resource Generation – Assumed LMP = $40											
BPA Base Schedule	200											
FMM Market Run Occurs	T-37.5			T-22.5			T-7.5			T+7.5		
	150			180			215			200		
RTD Market Run Occurs	T-2.5	T+2.5	T+7.5	T+12.5	T+17.5	T+22.5	T+27.5	T+32.5	T+37.5	T+42.5	T+47.5	T+52.5
	153	159	150	162	168	180	178	192	208	210	199	192
Metered Actuals	150	162	168	180	178	192	208	210	199	192	174	165
FMM IIE	$500			$200			-$150			$ -		
RTD IIE	-$10.00	-$30.00	$ -	$60.00	$40.00	$ -	$123.33	$76.67	$23.33	-$33.33	$3.33	$26.67
RTD UIE	$10.00	-$10.00	-$60.00	-$60.00	-$33.33	-$40.00	-$100.00	-$60.00	$30.00	$60.00	$83.33	$90.00
Total Imbalance	**$740**											

Scenario 2: Non-federal NPR Serving Load outside BA; Example 1: Schedule Decrease*

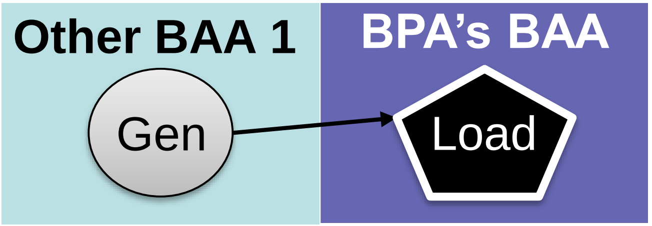


- RS Timeframe (by T-57):
  - Exporting NPR Base schedule = 150 MW
- Pre-Real time:
  - Decrease to schedule by T-20
- Real time:
  - Equal to T-20 schedule
- ATF:
  - Gen. Imbalance Charge – FMM IIE (difference between BS and FMM), RTD IIE (difference between FMM run and RTD) on NPR
  - Tag Imbalance Credit – FMM IIE, RTD IIE at interchange
    - BPA is currently reviewing to whom charges/credits associated with tag imbalance will be sent; currently under consideration is the tag Purchasing/Selling Entity (PSE)
  - Difference between charge and credit due to difference in LMPs

	Non-Participating Resource Generation – Assumed LMP = $40											
BPA Base Schedule	150											
FMM Market Run Occurs		T-37.5			T-22.5			T-7.5			T+7.5	
		150			150			145			145	
RTD Market Run Occurs	T-2.5	T+2.5	T+7.5	T+12.5	T+17.5	T+22.5	T+27.5	T+32.5	T+37.5	T+42.5	T+47.5	T+52.5
	145	145	145	145	145	145	145	145	145	145	145	145
Metered Actuals	145	145	145	145	145	145	145	145	145	145	145	145
FMM IIE		$ -			$ -			$50.00			$50.00	
RTD IIE	$16.67	$16.67	$16.67	$16.67	$16.67	$16.67	$ -	$ -	$ -	$ -	$ -	$ -
RTD UIE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Imbalance	**$200**											
	Interchange Point 1 (Export) – Assumed LMP = $42											
BPA Base Schedule	150											
FMM Market Run Occurs		T-37.5			T-22.5			T-7.5			T+7.5	
		150			150			145			145	
RTD Market Run Occurs	T-2.5	T+2.5	T+7.5	T+12.5	T+17.5	T+22.5	T+27.5	T+32.5	T+37.5	T+42.5	T+47.5	T+52.5
	145	145	145	145	145	145	145	145	145	145	145	145
Interchange Actuals												
FMM IIE		$ -			$ -			-$52.50			-$52.50	
RTD IIE	-$17.50	-$17.50	-$17.50	-$17.50	-$17.50	-$17.50	$ -	$ -	$ -	$ -	$ -	$ -
Total Imbalance	**-$210**											

* Note that an example with a schedule increase would result in credits for the generator and charges for the interchange

Scenario 3: External Resource Serving Load inside BA; Example 1: Schedule Decrease*



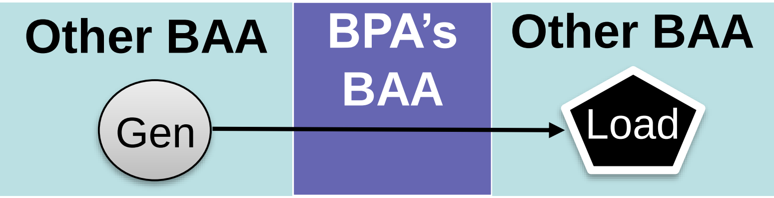
- RS Timeframe (by T-57):
  - Import Base schedule = 150 MW
- Pre-Real time:
  - Decrease to schedule by T-20
- Real time:
  - Equal to T-20 schedule
- ATF:
  - Tag Imbalance Charge – FMM IIE (difference between BS and FMM), RTD IIE (difference between FMM run and RTD) on interchange
    - BPA is currently reviewing to whom charges/credits associated with tag imbalance will be sent; currently under consideration is the tag Purchasing/Selling Entity (PSE)
  - Load Imbalance Credit – UIE at load
  - Difference between charge and credit due to difference in LMP/LAP

	Interchange Point 2 – Assumed LMP = $45											
BPA Base Schedule	-150											
FMM Market Run Occurs	T-37.5			T-22.5			T-7.5			T+7.5		
	-150			-150			-145			-145		
RTD Market Run Occurs	T-2.5	T+2.5	T+7.5	T+12.5	T+17.5	T+22.5	T+27.5	T+32.5	T+37.5	T+42.5	T+47.5	T+52.5
	-145	-145	-145	-145	-145	-145	-145	-145	-145	-145	-145	-145
FMM IIE	$ -			$ -			$56.25			$56.25		
RTD IIE	$18.75	$18.75	$18.75	$18.75	$18.75	$18.75	$ -	$ -	$ -	$ -	$ -	$ -
Interchange Total	**$225**											

	BPA Imbalance (Load) – Assumed LAP = $46											
BPA Base Schedule	150											
Metered Actuals	145											
RTD UIE	-$19.17	-$19.17	-$19.17	-$19.17	-$19.17	-$19.17	-$19.17	-$19.17	-$19.17	-$19.17	-$19.17	-$19.17
Load Total	**-$230**											

* Note that an example with a schedule increase would result in credits for the interchange

Scenario 3: External Resource Serving Load outside BA (Wheel-through); Example 2: Schedule Decrease*



- RS Timeframe (by T-57):
  - Wheeling Base schedule = 150 MW (import schedule = export schedule)
- Pre-Real time:
  - Decrease to wheeling schedule by T-20
- ATF:
  - Tag Imbalance Charge – FMM IIE (difference between BS and FMM), RTD IIE (difference between FMM and RTD) on import interchange
    - BPA is currently reviewing to whom charges/credits associated with tag imbalance will be sent; currently under consideration is the tag Purchasing/Selling Entity (PSE) (of this leg if different than second leg)
  - Tag Imbalance Credit – FMM IIE (difference between BS and FMM), RTD IIE (difference between FMM and RTD) on export interchange
    - BPA is currently reviewing to whom charges/credits associated with tag imbalance will be sent; currently under consideration is the tag Purchasing/Selling Entity (PSE) (of this leg if different than first leg)
  - Difference between charge and credit due to difference in LMPs at interchanges

	Interchange Point 1 (Import) – Assumed LMP = $42											
BPA Base Schedule	-150											
FMM Market Run Occurs	T-37.5			T-22.5			T-7.5			T+7.5		
	-150			-150			-145			-145		
RTD Market Run Occurs	T-2.5	T+2.5	T+7.5	T+12.5	T+17.5	T+22.5	T+27.5	T+32.5	T+37.5	T+42.5	T+47.5	T+52.5
	-145	-145	-145	-145	-145	-145	-145	-145	-145	-145	-145	-145
FMM IIE	$ -			$ -			$52.50			$52.50		
RTD IIE	$17.50	$17.50	$17.50	$17.50	$17.50	$17.50	$ -	$ -	$ -	$ -	$ -	$ -
Interchange Total	**$210**											

	Interchange Point 2 (Export) – Assumed LMP = $45											
BPA Base Schedule	150											
FMM Market Run Occurs	T-37.5			T-22.5			T-7.5			T+7.5		
	150			150			145			145		
RTD Market Run Occurs	T-2.5	T+2.5	T+7.5	T+12.5	T+17.5	T+22.5	T+27.5	T+32.5	T+37.5	T+42.5	T+47.5	T+52.5
	145	145	145	145	145	145	145	145	145	145	145	145
FMM IIE	$ -			$ -			-$56.25			-$56.25		
RTD IIE	-$18.75	-$18.75	-$18.75	-$18.75	-$18.75	-$18.75	$ -	$ -	$ -	$ -	$ -	$ -
Interchange Total	**-$225**											

* Note that an example with a schedule increase would result in credits for the import interchange and charges for the export interchange

Scenario 4: Slice Customer in BPA BA

- RS Timeframe (by T-57):
  - Slice customer-owned NPR Base schedule = 200 MW
  - Import Base Schedule = 300 MW
  - Slice Take (RTP) Schedule = 400 MW
  - Block Schedule = 500 MW
  - Total Schedules = 200+300+400+500 = 1400 MW
- Pre-Real time:
  - Decrease to NPR schedule by T-20
  - Decrease to Import schedule by T-20
- Real time:
  - NPR output equal to T-20 schedule
- ATF:
  - NPR: Gen. Imbalance Charge – FMM IIE and RTD IIE
  - Import: Imbalance Charge – FMM IIE and RTD IIE
  - Load: Load Imbalance Credit – UIE

- Footnote 1: Note that the same construct applies to block-only customers.

Scenario 4: Slice Customer in BPA BA (cont.)

	Non-Participating Resource Generation – Assumed LMP = $40											
BPA Base Schedule	200											
FMM Market Run Occurs	T-37.5			T-22.5			T-7.5			T+7.5		
	200			200			190			190		
RTD Market Run Occurs	T-2.5	T+2.5	T+7.5	T+12.5	T+17.5	T+22.5	T+27.5	T+32.5	T+37.5	T+42.5	T+47.5	T+52.5
	190	190	190	190	190	190	190	190	190	190	190	190
Metered Actuals	190	190	190	190	190	190	190	190	190	190	190	190
FMM IIE	$ -			$ -			$100.00			$100.00		
RTD IIE	$33.33	$33.33	$33.33	$33.33	$33.33	$33.33	$ -	$ -	$ -	$ -	$ -	$ -
RTD UIE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Imbalance	**$400**											

	Interchange Point (Import) – Assumed LMP = $45											
BPA Base Schedule	-300											
FMM Market Run Occurs	T-37.5			T-22.5			T-7.5			T+7.5		
	-300			-300			-285			-285		
RTD Market Run Occurs	T-2.5	T+2.5	T+7.5	T+12.5	T+17.5	T+22.5	T+27.5	T+32.5	T+37.5	T+42.5	T+47.5	T+52.5
	-285	-285	-285	-285	-285	-285	-285	-285	-285	-285	-285	-285
FMM IIE	$ -			$ -			$168.75			$168.75		
RTD IIE	$56.25	$56.25	$56.25	$56.25	$56.25	$56.25	$ -	$ -	$ -	$ -	$ -	$ -
Interchange Total	**$675**											

	BPA Imbalance (Load) – Assumed LAP = $45											
BPA Base Schedule	1,400											
Metered Actuals	1,370											
UIE	-$112.50	-$112.50	-$112.50	-$112.50	-$112.50	-$112.50	-$112.50	-$112.50	-$112.50	-$112.50	-$112.50	-$112.50
Load Total	**-$1,350**											

Next Steps

- Feedback on alternatives for sub-allocated and unallocated charge codes
  - Please submit to techforum@bpa.gov (with copy to your account executive) by Tuesday, August 12
- If interested in further discussion on Imbalance Charge Code Scenarios shared in today's presentation, please request this topic for the next Customer-Led Workshop
  - Additionally, previous scenarios could be reviewed (Dec. 2018, Apr. 2019, etc.), which can be found at the following link:
    - https://www.bpa.gov/Projects/Initiatives/EIM/Pages/Energy-Imbalance-Market.aspx
- August 25-26 Workshop:
  - Discuss Customer Feedback
  - Staff Proposal

APPENDIX: SUB ALLOCATION METHODS CONSIDERED

Sub-Allocation Methods Considered

- Direct Assignment
- Measured Demand vs. Metered Demand vs. Imbalance
  - The Metered Demand for each customer is their metered load, including losses.
  - The Measured Demand for each customer is their metered demand plus export schedules.
  - The Imbalance for each load customer is their imbalance as measured in the base codes.
- Magnitude vs. Direction vs. Imbalance Use
  - Magnitude allocation assigns a ratio share based on the magnitude of a given quantity (measured demand, metered demand or imbalance), regardless of the direction of their imbalance
  - Directional allocation assigns a ratio share based on the magnitude of a given quantity(measured demand, metered demand or imbalance), but only includes those customers whose imbalance is in the direction of the BA
  - Imbalance Use allocation assigns a ratio share based on the magnitude of a given quantity (measured demand, metered demand or imbalance), but only to those customers who had non-zero imbalance

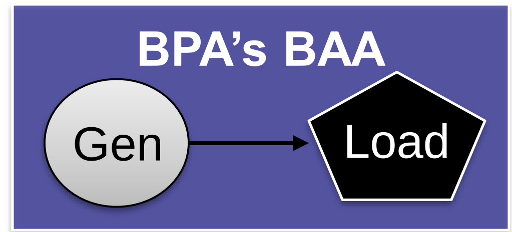
Sub-Allocation Methods Considered

	LSE 1	LSE 2	LSE 3	LSE 4	Total
Schedules (Internal)	500	1000	2000	1000	4500
Export Schedules	600	0	0	0	600
Metered Demand	550	950	2010	1000	4510
Export Schedules	600	0	0	0	600
Measured Demand	1150	950	2010	1000	5110
Imbalance	+50	-50	+10	0	+10

- **Metered Demand**
- Metered Demand Magnitude
  - Metered demand = 550 + 950 + 2010 + 1000 = 4510
  - LSE1 = X * 550/4510 = X * 12%
  - LSE2 = X * 950/4510 = X * 21%
  - LSE3 = X * 2010/4510 = X * 45%
  - LSE4 = X * 1000/4510 = X * 22%
- Metered Demand by Direction
  - Metered demand in the direction of BAA imbalance = 550 + 2010 = 2560
  - LSE1 = X * 550/2560 = X * 21%
  - LSE2 = 0
  - LSE3 = X * 2010/2560 = X * 79%
  - LSE4 = 0
- Metered Demand by Imbalance
  - Metered demand for LSEs with non-zero imbalance = 550 + 950 + 2010 = 3510
  - LSE1 = X * 550/3510 = X * 16%
  - LSE2 = X * 950/3510 = X * 27%
  - LSE3 = X * 2010/3510 = X * 57%
  - LSE4 = 0
- **Measured Demand**:
- Measured Demand Magnitude
  - Measured demand = 1150 + 950 + 2010 + 1000 = 5510
  - LSE1 = X *1150/5110 = X * 22%
  - LSE2 = X * 950/5110 = X * 19%
  - LSE3 = X * 2010/5110 = X * 39%
  - LSE4 = X * 1000/5110 = X * 21%
- Measured Demand by Direction
  - Measured demand in the direction of BAA imbalance = 1150 + 2010 = 3160
  - LSE1 = X * 1150/3160 = X * 36%
  - LSE2 = 0
  - LSE3 = X * 2010/3160 = X * 64%
  - LSE4 = 0
- Measured Demand by Imbalance
  - Measured demand for LSEs with non-zero imbalance = 1150 + 950 + 2010 = 4110
  - LSE1 = X * 1150/4110 = X * 28%
  - LSE2 = X * 950/4110 = X * 23%
  - LSE3 = X * 2010/4110 = X * 49%
  - LSE4 = 0
- **Imbalance**:
- Imbalance Magnitude
  - Total absolute imbalance = abs(+50) + abs(-50) + abs(10) + abs(0) = 110
  - LSE1 = X * abs(+50)/110 = X * 45%
  - LSE2 = X * abs(-50)/110 = X * 45%
  - LSE3 = X * abs(+10)/110 = X * 9%
  - LSE4 = abs(0)
- Imbalance by Direction
  - Total imbalance = +50 + (-50) + (10) + (0) = 60
  - LSE1 = X * 50/60 = X * 83%
  - LSE2 = X * (-50)/60 (to make whole – imbalance?) *OR* 0 (for penalties etc)
  - LSE3 = X * 10/60 = X * 17%
  - LSE4 = 0

Scenario 1: Non-federal NPR Serving Load in BA; Example 2b: Actual Output Above Schedule

- RS Timeframe (by T-57):
  - NPR Base schedule = 200 MW
- Pre-Real time:
  - No changes
- Real time:
  - Output = 10 MW above schedule
- ATF:
  - Gen. Imbalance Credit – UIE (difference between 5-minute market expectation and actual output)

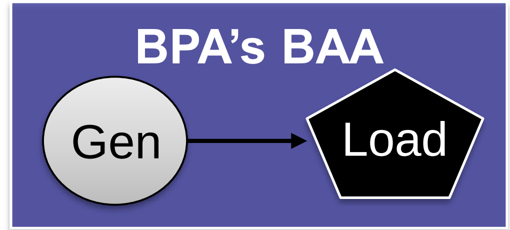


	Non-Participating Resource Generation – Assumed LMP = $40											
BPA Base Schedule	200											
FMM Market Run Occurs	T-37.5			T-22.5			T-7.5			T+7.5		
	200			200			200			200		
RTD Market Run Occurs	T-2.5	T+2.5	T+7.5	T+12.5	T+17.5	T+22.5	T+27.5	T+32.5	T+37.5	T+42.5	T+47.5	T+52.5
	200	200	200	200	200	200	200	200	200	200	200	200
Metered Actuals	210	210	210	210	210	210	210	210	210	210	210	210
FMM IIE	$ -			$ -			$ -			$ -		
RTD IIE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RTD UIE	-$33.33	-$33.33	-$33.33	-$33.33	-$33.33	-$33.33	-$33.33	-$33.33	-$33.33	-$33.33	-$33.33	-$33.33
Total Imbalance	**-$400**											

- Footnote 1: Note that, while PRs will receive charges and credits directly from the market operator, and likely will not have their FMM and RTD awards equal to their base schedule, the concept that actual output differing from 5-minute market expectation results in UIE applies to PRs as well as NPRs

Scenario 1: Non-federal NPR Serving Load in BA; Example 3b: Schedule Increase

- RS Timeframe (by T-57):
  - NPR Base schedule = 200 MW
- Pre-Real time:
  - Increase to schedule by T-20
- Real time:
  - Equal to T-20 schedule
- ATF:
  - Gen. Imbalance Credit – FMM IIE (difference between BS and FMM run), RTD IIE (difference between FMM run and RTD run)



	Non-Participating Resource Generation – Assumed LMP = $40											
BPA Base Schedule	200											
FMM Market Run Occurs	T-37.5			T-22.5			T-7.5			T+7.5		
	200			200			210			210		
RTD Market Run Occurs	T-2.5	T+2.5	T+7.5	T+12.5	T+17.5	T+22.5	T+27.5	T+32.5	T+37.5	T+42.5	T+47.5	T+52.5
	210	210	210	210	210	210	210	210	210	210	210	210
Metered Actuals	210	210	210	210	210	210	210	210	210	210	210	210
FMM IIE	$ -			$ -			-$100.00			-$100.00		
RTD IIE	-$33.33	-$33.33	-$33.33	-$33.33	-$33.33	-$33.33	$ -	$ -	$ -	$ -	$ -	$ -
RTD UIE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Imbalance	**-$400**											

- Footnote 1: Note that, while PRs will receive charges and credits directly from the market operator, and likely will not have their FMM and RTD awards equal to their base schedule, the concept that changes to base schedules result in IIE can apply to PRs as well as NPRs
- Footnote 2: Note that a curtailment to a schedule after T-20 will result in a similar outcome. The main difference is the timing; the adjustment to the schedule will be reflected in the EIM optimization once that information becomes available. For instance, if a curtailment occurs 3 minutes into an hour, the 4 FMM optimizations and the first 2 RTD optimizations have already run and will not reflect that changed schedule, but the subsequent RTD optimizations will

TC-22, BP-22 and EIM Phase III Customer Workshop

July 29 & 30, 2020

Day 2

ISSUE: POWER RATES

Tier 2 Rates

EIM Benefits and Charges in Power Rates

TIER 2 RATES

Agenda

- Review BP-20 Tier 2 rates
- Share our BP-22 Tier 2 Short Term and Load Growth rate proposals
- Discuss Tier 2 Vintage rates

Previous and current Tier 2 rates

- BP-12 through BP-20 Tier 2 Rates in $/MWh:

Fiscal Year	Rate Case	Short Term	Load Growth	VR1-2014	VR1-2016
2012	BP-12	$46.48	N/A	N/A	N/A
2013	BP-12	$48.69	$48.63	N/A	N/A
2014	BP-14	$35.58	$35.58	N/A	N/A
2015	BP-14	$39.65	$41.62	$41.56	N/A
2016	BP-16	$29.72	$45.18	$44.72	$40.60
2017	BP-16	$32.01	$49.60	$49.08	$43.18
2018	BP-18	$27.20	$47.68	$51.40	$46.50
2019	BP-18	$24.97	$45.42	$53.02	$48.02
2020	BP-20	$30.32	N/A	N/A	N/A
2021	BP-20	$33.00	N/A	N/A	N/A

- In BP-20, the only Tier 2 rate was the Short Term rate.
  - Vintage rates expired at the end of FY 2019.
  - Customers with the Tier 2 Load Growth rate election did not have Above-RHWM Load greater than 1 aMW.
  - The load shaping charge is applied to Above-RHWM Load less than 1 aMW.

BP-20 Tier 2 Short Term rate

- BP-20 Short Term rate components:

Fiscal Year	Forecast Power Price	Risk Adder	Losses	TSS	Overhead Adder	Short Term Rate	Short Term amounts
	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	annual aMW
2020	$28.27	$0.00	$0.87	$0.11	$1.07	$30.32	54.193
2021	$30.84	$0.00	$0.94	$0.11	$1.11	$33.00	63.497

- In BP-20 BPA did not make any power purchases to support its sales at Tier 2 rates; Tier 2 obligations were met with available Firm Surplus amounts (assuming 1937 water after meeting firm load obligations).
  - Current Tier 2 load estimates for FY 2022 and FY 2023 are higher than the Tier 2 amounts in FY 2020 and FY 2021.
  - Tier 2 loads will be set November 1, 2020 for BP-22.

BP-20 forecast power prices

- In BP-20, the forecast power prices (aka Remarketing Value) used to set the Short Term rates were based on:
  - Average ICE MID-C settlement prices that were pulled during two separate five-consecutive-business-day periods (the last full week of September 2018 and last full week of March 2019) for a flat block of power in FY 2020 and FY 2021;
  - Plus $0.50/MWh.
- The 50 cent adder was used to convert settlement prices to physical prices. It was based on the difference between:
  - previously made Tier 2 power purchases; and
  - ICE settlement prices on the date the Tier 2 power purchases were made for the same years of the power purchases.

BP-22 Tier 2 rate proposals

- Staff proposes to use the same methodologies used in BP-20 to set BP-22 Tier 2 rates.
  - If BPA has Firm Surplus power to meet its entire Tier 2 obligation in a fiscal year, then that fiscal year's Tier 2 rate would be based on ICE settlement prices (pulled during the last full week of September 2020 and the last full week of March 2021) for a flat block of power in the same fiscal year, plus $0.50.
  - If BPA purchases an annual flat block of power to meet all or a portion of its Tier 2 obligation in a fiscal year, then that fiscal year's Tier 2 rate would be based on the purchase price for such power.
- Staff proposes to use this methodology for Short Term and Load Growth rates. The Load Growth rate would be set equal to the Short Term rate.

Carbon adder in Tier 2 rates?

- Firm Requirements Power sold at Tier 2 Short Term and Load Growth rates includes the attributes of BPA's system fuel mix regardless of whether the power is sourced from the FCRPS system or is purchased by BPA.
- Although perhaps not ripe for BP-22, BPA would like customer input on Tier 2 rates and low carbon attributes in light of the increased market value of BPA's low carbon system mix in the Northwest.
  - For example, should BPA include a carbon cost adder in the Short Term and Load Growth rates to reflect the added-value of low carbon in BPA's system fuel mix as well as the lost market opportunity?
  - Revenues from a carbon adder would go to Tier 1 rates (composite cost pool).
- The recently signed Clean Energy Transformation Act (CETA) in Washington state will increase the demand for low carbon energy within the Northwest. This could create pressure to keep BPA's system fuel mix as carbon-free as possible.
- Any proposals to account for carbon must be consistent with the Tiered Rate Methodology (TRM).

Vintage rates

- If so requested, BPA could offer Tier 2 Vintage rates for customers with specific resource objectives (solar, wind, market, etc.)
- Customers looking for direct market purchases outside of the Tier 2 Short Term/Load Growth rate based framework should contact BPA’s trading floor.

Next steps

- Comments or questions? Email techforum@bpa.gov and copy your Account Executive.
- Please provide comments by August 12^{th}.

EIM BENEFITS AND CHARGES IN POWER RATES

Agenda

Discuss treatment of EIM charges codes within power rates in BP-22.

We will cover:

1. EIM settlements (dispatch benefits) to Power Services as a Participating Resource Scheduling Coordinator (PRSC); and
2. Charges allocated to Power Services from Transmission Services to recover the cost of EIM settlements to Transmission Services as an EIM Entity Scheduling Coordinator (EESC).

PRSC Charge Codes

- Participating Resources settle directly with CAISO for awards and deviations from their operating targets
- Power Services can use its Participating Resources to bid surplus power and balancing reserves into the EIM market
  - Surplus power sales are forecast as part of the net secondary revenue (NSR) credit in the non-Slice cost pool
  - Balancing reserves are a revenue credit in the composite cost pool (part of Generation Inputs for Ancillary, Control Area, and Other Services Revenues)

EIM dispatch benefits

- The E3 Study is our best estimate of future-state EIM benefits.
  - The E3 Study estimated annual dispatch benefits of ~$36-40 million/year
  - It likely does not represent a reasonable expectation for BP-22 benefits
- There is a lot of uncertainty for this rate period, for example:
  - BPA has not yet made the final decision to join the EIM
  - BPA’s level/method/effectiveness of participation and rate of learning is unknown
  - How BPA’s participation will impact other marketing actions is unknown
- There are also known reasons why the E3 benefits projection is not representative of this rate period:
  - If BPA joins the EIM, participation is expected beginning in month 6 of the BP-22 rate period
  - BPA’s participation will not be “mature”
- Instead of finding a way to scale down the E3 benefits projection to represent a forecast of BPA’s EIM benefits in BP-22, we propose to address the above issues by having EIM benefits and costs be net neutral in power rates for this rate period

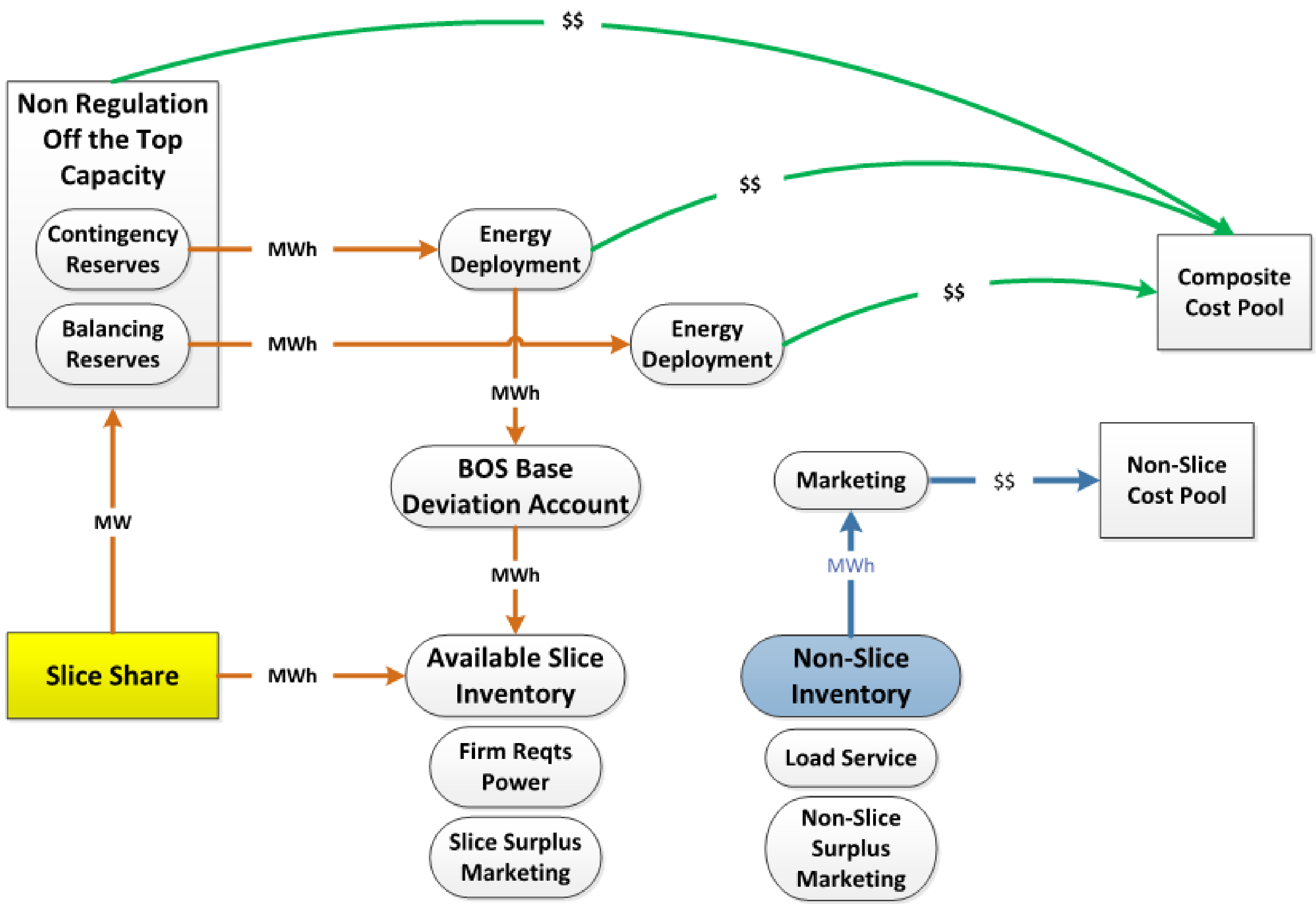
EIM dispatch benefit recommendation

- Staff is leaning towards setting EIM net dispatch benefits to be equivalent to expected ongoing costs in BP-22
  - EIM start-up costs are already being incurred, but Power Services expects an additional ~$2.4 million/year of ongoing costs once participation begins
  - Credit benefits such that EIM will have neither a positive nor negative impact on rates in BP-22
  - Results in a BP-22 NSR increase of ~$2.4 million/year
- Applying a conservative benefit credit for purposes of setting base rates will allow BPA to gain experience in market, giving BPA room to develop procedures and strategies for EIM participation. In addition, this approach follows BPA's general goal of decreasing BPA's dependence on its secondary revenue over time.
- **Actual EIM benefits will still accrue to BPA's customers**
  - When actual benefits are greater than the amount assumed for purposes of setting power rates, customers would see the benefit through less exposure to risk mechanisms and more stable rates.
  - Actual benefits observed may carry through to the Slice True-up depending on the approach used for sharing the benefits of the EIM with the Slice product (next slide).

Balancing reserves and Slice customers

- Reserves (balancing and contingency) are "off-the-top" obligations for the FCRPS, with the revenue credit going to Slice and non-Slice customers in the composite cost pool.
- An "off-the-top" obligation for Slice customers means the Slice "capability" is reduced accordingly. Slice customers share in the operational obligation and receive a share of the associated revenue.
  - Energy associated with Contingency Reserve deployments is tracked and accounted, then deducted (pro-rata) from each Slice customer's energy account (BOS Deviation Account). We expect this would continue under the EIM.
  - Energy associated with Balancing Reserve activity nets to roughly zero over time, so as a simplifying procedure energy is not tracked for the purpose of Slice customer energy accounts. If BPA joins the EIM, the non-regulating portion of Balancing Reserves will be offered into the market so this "net zero" energy accumulation may not continue. Any associated energy would need to be tracked and accounted accordingly if the energy revenue and cost is shared with the Slice product.

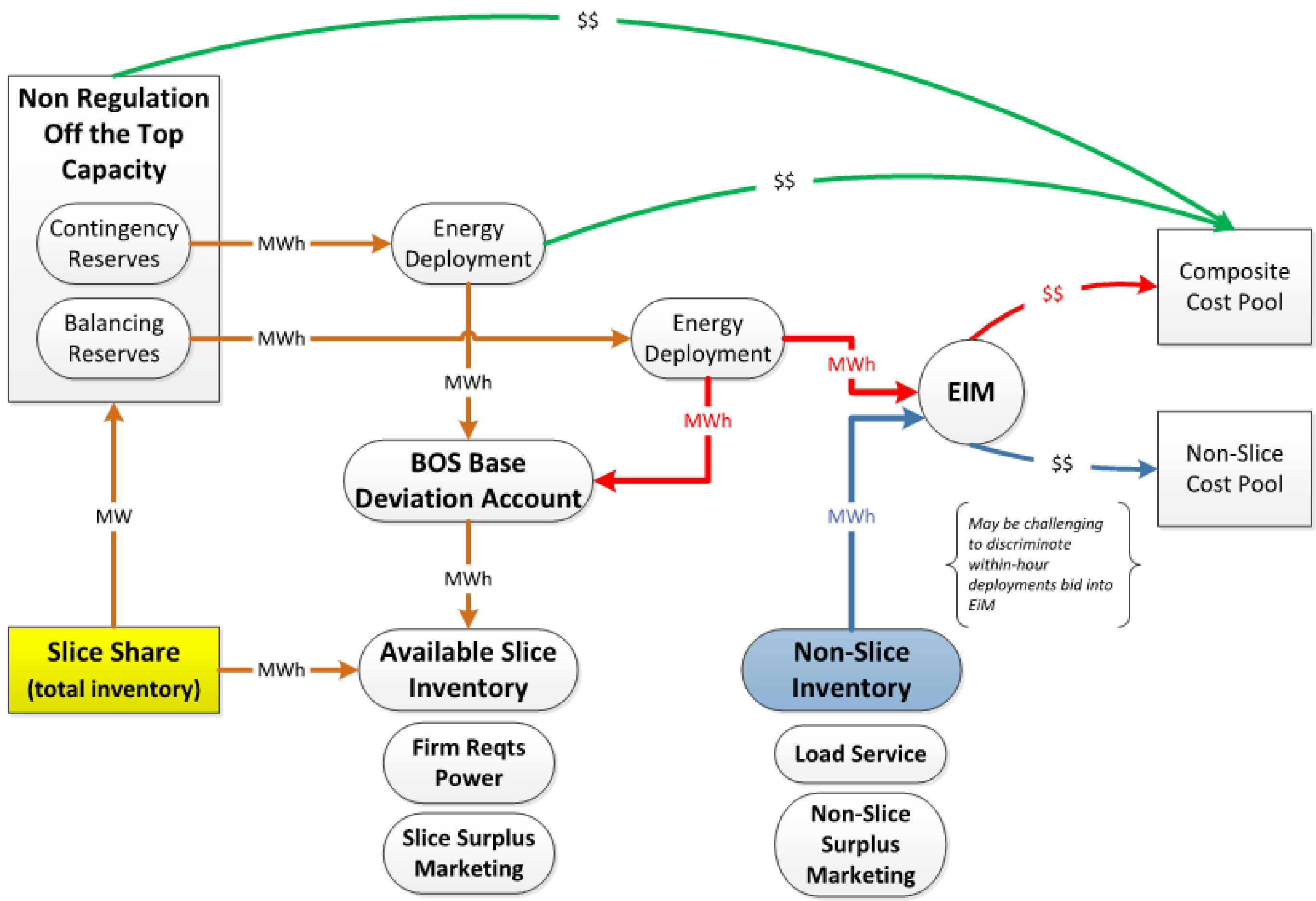
OFF THE TOP STATUS QUO



OFF THE TOP OPTION 1

Treat capacity and energy as off the top

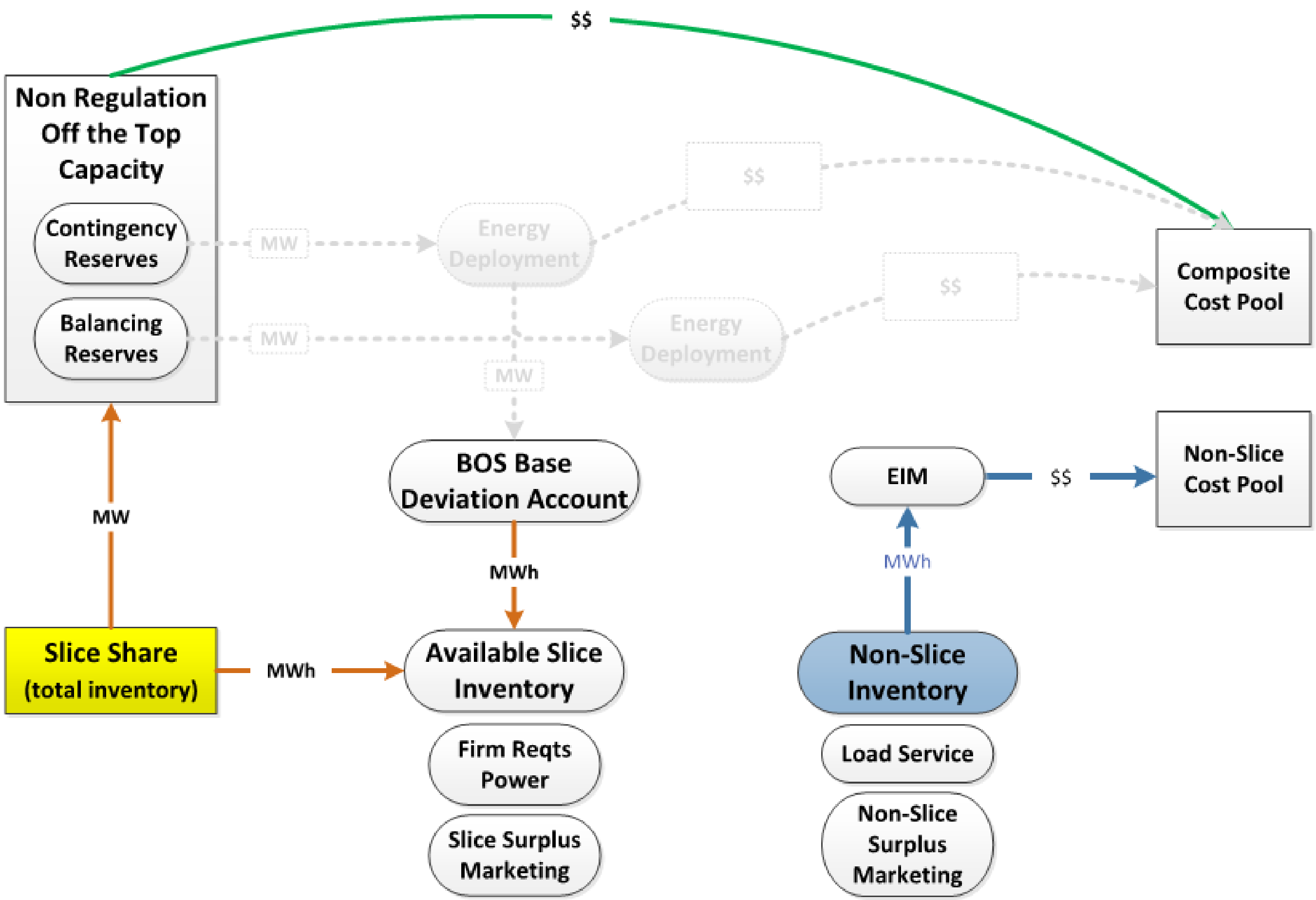
The Gen Res Inc constraint includes the non-reg capacity, BOS deviation account is adjusted for associated energy, customers receive revenue associated with capacity and energy



OFF THE TOP OPTION 2

Treat capacity as off the top, but not the energy

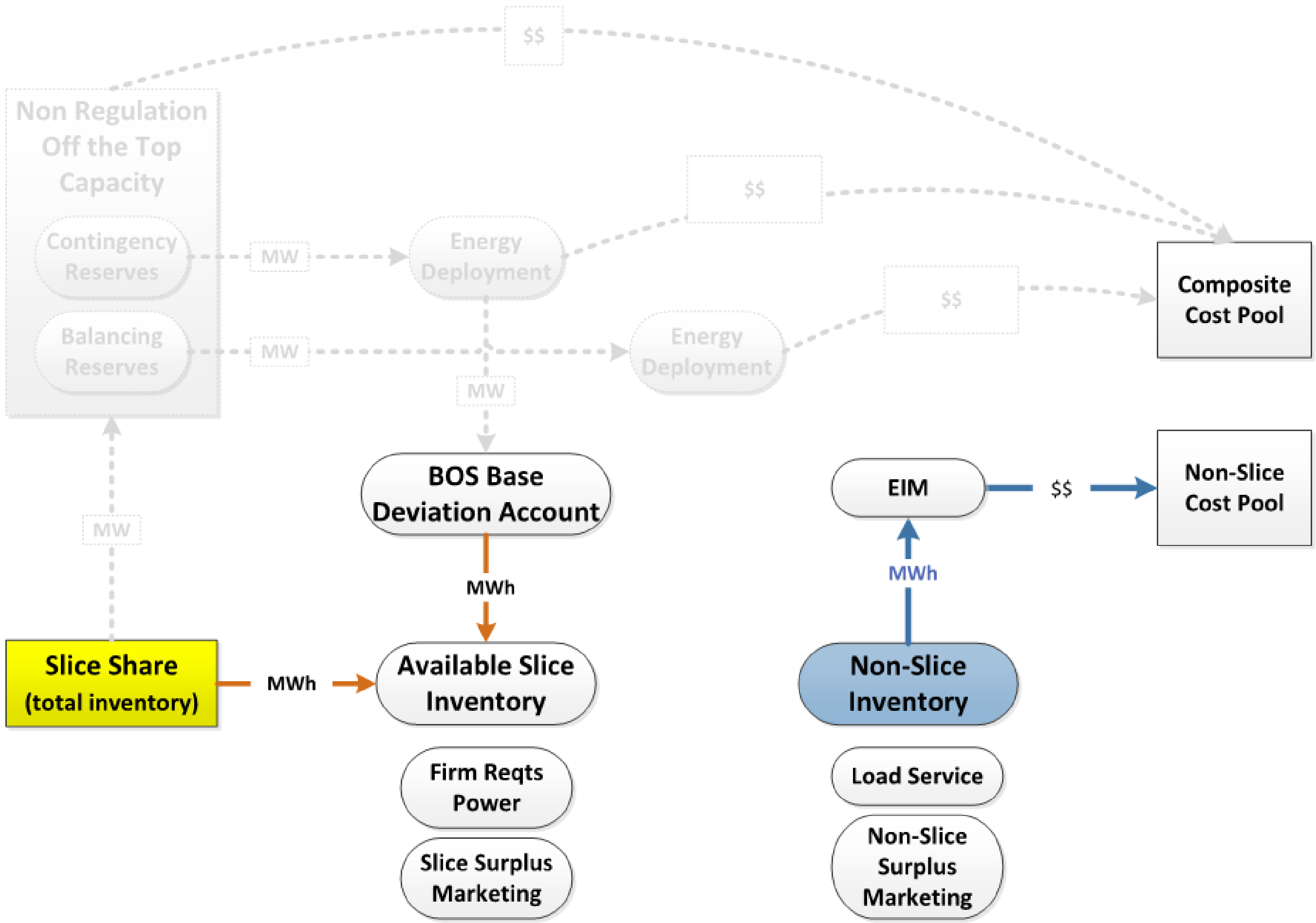
The Gen Res Inc constraint includes the non-reg capacity, no energy accounting is done, customers receive revenue associated with non-reg capacity only



OFF THE TOP OPTION 3

Treat neither capacity or energy as off the top

The Gen Res Inc constraint excludes the non-reg capacity, no energy accounting is done, customers receive no capacity or energy revenue for non-reg capacity needs and use



EESC Charge Codes

- Power Services will be allocated a share of the EESC charge codes in two ways:
  - As a BPA Transmission customer (for PTP transmission)
  - EIM costs and credits for Load Following customers
- Most EESC charge codes (in terms of magnitude of dollars) will be sub-allocated from Transmission to its customers.
  - This means Power will be allocated its share of sub-allocated EESC charge codes for PTP transactions and for load following customers
  - The methodology used to determine a customer’s share of a charge code will be published in the Transmission rate schedules
- Charges that are not sub-allocated will be incorporated within Transmission rates.
  - This means the rates that Power Services pays as a BPA transmission customer could be impacted by these charge codes.

Sub-allocated and not-sub-allocated charge codes

Sub Allocated Charge Codes			
Charges will be allocated as received by EESC			
Imbalance	Uninstructed Imbalance Energy (UIE)	Neutrality Charges	Real Time (RT) Imbalance Energy Offset EIM
	FMM Instructed Imbalance Energy (IIE)		Real Time Congestion Offset EIM
	Real-Time Instructed Imbalance Energy (RT IIE)		Real Time Marginal Losses Offset EIM
Under/Over Scheduling	Under/Over Schedule Load Charge		Real Time Imbalance Energy Offset
	Under/Over Schedule Load Allocation		Real Time Unaccounted for EIM Energy Settlement

Not Sub Alloacted Charge Codes	
Charges will be incorporated in Transmission rates	
EP Penalty Allocation Payment	Flexible Ramp Forecast Movement Allocation
Default Invoice Interest Payment	Daily Flexible Ramp Up Uncertainty Award Allocation
Default Invoice Interest Charge	Monthly Flexible Ramp Up Uncertainty Award Allocation
GMC-EIM Transaction Charge	Daily Flexible Ramp Down Uncertainty Capacity Settlement
SMCR -Settlements, Metering, and Client Relations	Daily Flexible Ramp Down Uncertainty Award Allocation
Invoice Late Payment Penalty	Monthly Flexible Ramp Down Uncertainty Award Allocation
Financial Security Posting (Collateral) Late Payment Penalty	Invoice Deviation Interest Distribution
Shortfall Receipt Distribution	Invoice Deviation Interest Allocation
Shortfall Allocation Reversal	Generator InterconnectionGIP Forfeited Deposit Allocation
Shortfall Allocation	Daily Neutrality Adjustment
Default Loss Allocation	Monthly Neutrality Adjustment
Flexible Ramp Forecast Movement Settlement	Bid Cost Recovery EIM Settlement
Daily Flexible Ramp Up Uncertainty Capacity Settlement	Real Time Bid Cost Recovery Allocation EIM

*The yellow box of imbalance charges represents about 70-80% of charges that will be settled with Transmission as the EESC

Including Sub-allocated EESC Charge Codes in Power Rates

- Power Services will incur imbalance charges as it manages BPA's non-Slice inventory (balancing purchases and secondary sales).
- At this point it seems appropriate to include sub-allocated EESC charge codes from Transmission in the non-Slice Cost Pool.
  - If Slice customers receive a share of EIM dispatch benefits it may be appropriate to allocate a commensurate portion of EESC charge codes to Slice customers.
- There is work ongoing to determine how Power's share of EESC charge codes will be calculated. Once determined, these charge codes may be forecast and included in Power rates (we may forecast $0 for BP-22.)
  - Currently Power forecasts $0 for EI/GI in rates.
  - There is not a lot of information to use to develop a forecast of these charges in BP-22.

Non-Slice Cost Pool

- The non-Slice customer charge applies to Load Following and Block sales (including the Block portion of the Slice/Block product)
- To ensure there isn't double counting if Transmission sub-allocates EIM neutrality costs using metered demand or measured demand as an allocation method, we propose Block demand amounts be allocated to Power Services (along with Load Following amounts).
- Any variations between what is billed to Power Services during the rate period and what was assumed in rates will impact financial reserves.

Including “not sub-allocated” EESC Charge Codes in Power Rates

- Power Services will incorporate the forecast impacts to Transmission rates due to inclusion of EIM charge codes into Power’s forecast of its Transmission expenses.
- If transmission expenses in the Composite cost pool (transmission used to serve federal obligations) are impacted by “not sub-allocated” EESC charge codes, then any variations between assumptions in the rate case and actuals will be subject to the Slice True-Up.
- Non-Slice customers will be impacted by the difference between the rate case assumption and actuals via financial reserve levels.

Summary

- For BP-22 the general proposal is to have power rates largely net neutral in regards to EIM charges (costs and benefits).
- If we implement a method to allocate a portion balancing reserves offered into the EIM to Slice customers, then we need to also develop a method for Slice customers to share in any costs associated with the EIM and the dispatch of such balancing reserves paid to either Transmission Services or CAISO.

Next steps

- Comments or questions? Email techforum@bpa.gov and copy your Account Executive.
- Please provide comments by August 12.

Wrap up and Next Steps

- Comment period
  - Customers should submit comments by August 12, 2020 to the techforum@bpa.gov

APPENDIX

Customer Led Workshop Protocol

- Submit a workshop request no later than one week before the scheduled date (see slide 4 for dates).
- Requests must include a list of topics/issues you wish to cover if you are requesting Bonneville SME support.
- Discussions/workshops will only cover previously reviewed materials.
- Customers must inform BPA if A/V resources are required to include remote participants and/or present materials **through virtual meeting**.
- BPA will verify that it will staff for the requested topics within three business days via Tech Forum.

EIM Issue Inter-Dependencies Identified