

# Power from the prairie Concept Development Study (CDS)



Volume 2: Exhibits PUBLIC EDITION

March 23, 2023



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NTERREGIONAL TRANSMISSION FOR THE FUTURE

### I. TRANSMITTAL LETTER

March 23, 2023

# RE: Power from the Prairie Project Concept Development Study Report, Volume 2 (Public)

Power from the Prairie LLC (PftP LLC, <u>www.powerfromtheprairie.com</u>) and our PftP subcontractor LLC Team member, Hitachi Energy, are pleased to provide the attached Final Report for the Power from the Prairie project Concept Development Study (CDS, or the "Study").

This Volume 2 of the Report provides the Public Exhibits referenced in Volume 1.

Sincerely,

Bos Schulto.

Bob Schulte Managing Member



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### **II. EXHIBITS**



#### **EXHIBIT III-1. THE CDS PARTICIPANTS**





#### EXHIBIT III-1. THE CDS PARTICIPANTS (continued)





EXHIBIT III-1. THE CDS PARTICIPANTS (continued)





#### **EXHIBIT III-2. INITIAL POLL OF CDS PARTICIPANTS**





EXHIBIT III-2. INITIAL POLL OF CDS PARTICIPANTS (continued)

# Initial Survey Results (continued) Question 10: Other Motivations?

# Two responses:

"We are interested in cost effective, reliable solutions to meet our forecasted obligations that are local to our service territory."

"To improve the reliability of Gregory County pumped hydro storage."





#### EXHIBIT III-2. INITIAL POLL OF CDS PARTICIPANTS (continued)





#### **EXHIBIT III-3: CDS REVIEW COMMITTEE AND SUBCOMMITTEES**

Exhibit III-3A. CDS Review Committee

Participant 🔽	Name 💌	<u>Title</u>
BEPC	Becky Kern	VP, Resource Planning & Rates
BHEUST	Doug Kusyk	VP and General Counsel
BHSC	Eric Egge	Director, Corporate Development
MP	Randi Nyholm	Manager, RTO Coordination
MRES	Ray Wahle	Executive Consultant
OPPD	Dan Lenihan	Director - Planning & Strategy
SCPPA	Dawn Lindell	GM, Burbank Water & Power
	Mandip Samra	Asst. GM, Burbank Water & Power



Participant	Name 🔽	<u>Title</u>
BEPC	Aaron Ramsdell	Manager, Power Modeling
BHEUST		
BHSC	Amanda Thames	Resource Planning Manager
MP	Scott Hoberg	Supervising Engineer
	Eric Palmer	Supervisor, Utility Planning
MRES	Eric Carl	Economist/Resource Planner
OPPD	Colton Kennedy	Manager-Corporate Planning
	Dan Lenihan	Director - Planning & Strategy
SCPPA	Mandip Samra	Asst. GM, Burbank Water & Power



#### Exhibit III-3C. CDS Task 2 (Technology and Markets) Subcommittee

Participant 🔽	Name 🔽	<u>Title</u>
BEPC	Jeremy Severson	Manager, Transmission Planning
BHEUST	Doug Kusyk	VP and General Counsel
BHSC	Eric East	Manager, Tariff and Contract Administration
MP	Christian Winter	Supervising Engineer
	Peter Schommer	Manager – Power Delivery and Asset Management
	Randi Nyholm	RTO Coordination Manager
MRES	Richard Dahl	Director of Transmission Services
OPPD	Josh Verzal	Manager-Transmission Planning
SCPPA	Riad Sleiman	Asst GM - Electric Services, BWP



#### Exhibit III-3D. CDS Task 3A (Organization) Subcommittee

Participant 🔻	Name 🔽	<u>Title</u>
BEPC	Jason Doerr	Manager, RTO and Delivery Services
BHEUST	Doug Kusyk	VP and General Counsel
BHSC	Eric Egge	Director, Corporate Development
MP	Julie Pierce	VP – Strategy & Planning
	Dan Gunderson	VP – Transmission & Distribution
MRES	Austin Hoekman	Director of Operations
OPPD	Joe Lang	Director - Energy Regulatory Affairs
SCPPA	Dawn Lindell	GM, Burbank Water & Power
	Mandip Samra	Asst. GM, Burbank Water & Power



	Exhibit III-3E.	CDS Task 3B	(Regulatory)	Subcommittee
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Participant 💌	Name 🔽	<u>Title</u>
BEPC	Tyler Hamman	VP – Government Relations
BHEUST	Doug Kusyk	VP and General Counsel
BHSC	Eric Egge	Director, Corporate Development
MP	Julie Pierce	VP – Strategy & Planning
	Dan Gunderson	VP – Transmission & Distribution
MRES	John Weber	Senior Transmission Engineer – Tariffs
OPPD	Joe Lang	Director - Energy Regulatory Affairs
SCPPA	Dawn Lindell	GM, Burbank Water & Power
	Mandip Samra	Asst. GM, Burbank Water & Power



#### Task 1: Modeling—Building the Base Case

#### **EXHIBIT V-1. PROMOD to GRIDVIEW BENCHMARKING**

Exhibit V-1A. Comparison of PROMOD and Gridview results, graphical

Example Pricing Hub LMP Comparison, Northeast Kentucky Interface PROMOD in Blue, Gridview in Orange





Exhibit V-1B. Comparison of PROMOD and Gridview results, graphical

Example Pricing Hub LMP Comparison, EES Western Interface PROMOD in Blue, Gridview in Orange





Exhibit V-1C. Comparison of PROMOD and Gridview results, graphical

Example Pricing Hub LMP Comparison, NDEX Interface PROMOD in Blue, Gridview in Orange





#### Exhibit V-1D. Comparison of PROMOD and Gridview results, tabular

Row Labels	-	Sum of Promod	Sum of GridView	Row Labels	-
CC		1,258,648,451	1,271,038,199	<b>•</b> MHEB	
CT Gas		168,101,235	150,505,065	MISO	
CT Oil		4,382	6,900	СС	
CT Other		18,654	15,197	CT Gas	
Geothermal		385,818	395,424	CT Oil	
IC Gas		2,734,112	2,524,414	CT Other	
IC Oil		10,055	5,521	CT Renewable	
IC Renewable		706,097	724,732	Geothermal	
IGCC		5,460,779	5,378,008	IC Gas	
Nuclear		586,614,777	586,792,360	IC Oil	
ST Coal		172,149,038	191,932,469	IC Renewable	
ST Gas		17,115,895	17,825,546	IGCC	
ST Other		2,339,316	2,333,780	Nuclear	
ST Renewable		15,343,831	15,270,530	PV + Batt	
Wind		296,496,897	292,651,697	Solar PV	
Solar PV		96,236,297	95,867,051	ST Coal	
CT Renewable		1,349,673	1,349,454	ST Gas	
PV + Batt		68,389,016	68,274,770	ST Other	
Interruptible Loads		27	-	ST Renewable	
External Transaction		12,196,669	9,519,542	Wind	
Conventional Hydro		99,303,818	98,587,241	Conventional Hyd	Iro
Battery Storage		1,639,712	2,723,294	Pumped Storage	Hydro
Pumped Storage Hydro		9,998,322	5,657,189	Industrial Loads	
Industrial Loads		15,794,280	15,794,280	External Transact	ion
Grand Total		2,831,037,152	2,835,172,664	Interruptible Load	ds
				DIM Interconnectic	

Row Labels	Sum of Promod	Sum of GridView
<b>•</b> MHEB	37,909,057	36,829,313
MISO	744,720,716	729,461,612
CC	330,154,892	318,749,477
CT Gas	35,198,336	28,835,328
CT Oil	4,237	6,783
CT Other	16,536	16,357
CT Renewable	55,558	55,538
Geothermal	37,430	41,739
IC Gas	1,278,414	1,238,815
IC Oil	372	1,040
IC Renewable	256,095	259,662
IGCC	3,571,953	3,728,447
Nuclear	92,603,659	92,609,598
PV + Batt	5,060,987	5,055,779
Solar PV	65,714,675	65,492,376
ST Coal	60,925,892	66,908,319
ST Gas	12,106,937	11,620,585
ST Other	729,282	720,078
ST Renewable	4,454,853	4,406,958
Wind	105,626,848	104,113,799
Conventional Hydro	9,168,702	9,197,518
Pumped Storage Hydr	o 1,472,492	451,681
Industrial Loads	7,717,560	7,717,560
External Transaction	8,565,007	8,234,173
Interruptible Loads	(2)	-
PJM Interconnection	957,879,046	997,847,065
Southeast	516,307,742	506, 182, 104
Southwest Power Pool	343,715,817	340, 192, 935
<b>∃</b> TVA	173,316,152	172,916,748
TVA - Other	57,188,622	56,746,196
Grand Total	2,831,037,152	2,840,175,972

Row Labels 🗾 🗾	Sum of Promod	Sum of GridView				
■ MHEB	37,909,057	36,829,313				
■ MISO	744,720,716	729,461,612				
PJM Interconnection	957,879,046	997,847,065				
Southeast	516,307,742	506, 182, 104				
Southwest Power Pool	343,715,817	340,192,935				
CC	72,714,328	74,877,197				
CT Gas	31,422,325	23,123,372				
CT Oil	85	6				
CT Other	2,119	2,398				
Geothermal	348,388	354,050				
IC Gas	1,355,304	1,200,608				
IC Oil	9,674	4,804				
IC Renewable	45,897	46,361				
Nuclear	14,909,694	14,957,252				
PV + Batt	6,468,016	6,461,054				
Solar PV	1,622,885	1,621,805				
ST Coal	52,902,444	56,699,512				
ST Gas	808,719	957,424				
ST Other	249,814	251,083				
ST Renewable	36,793	36,670				
Wind	140,941,717	138,653,113				
Battery Storage	1,639,712	2,855,309				
Conventional Hydro	14,182,569	14,170,251				
Pumped Storage Hydro	423,641	313,524				
External Transaction	3,631,662	3,607,141				
Interruptible Loads	32	-				
<b>TVA</b>	173,316,152	172,916,748				
TVA - Other	57,188,622	56,746,196				
Grand Total	2,831,037,152	2,840,175,972				



#### Task 1: Modeling, Defining the HVDC and AC Transmission Layouts

#### **EXHIBIT V-2. DEFINING THE DC AND AC TRANSMISSION LAYOUTS**

Exhibit V-2A: The Base Case.



The MISO "Tranche 1" transmission projects shown here were added to the Base Case. •



Exhibit V-2B: Scenario A: TransWest Express HVDC and HVAC



• TransWest plans a 3,000 MW HVDC line from Wyoming to IPP site at Delta, Utah. There, it connects to the Southern Transmission system 2,400 MW HVDC line to Southern California, and also continues from Delta to Nevada via a TransWest 500 KVAC development.



Exhibit V-2C. Scenario A: Soo Green HVDC & HVAC



- The Soo Green project includes a 2,100 MW HVDC underground transmission line along railroad right of way from the Killdeer substation near Mason City, Iowa to Plano, Illinois near Chicago.
- It would span between the MISO and PJM RTOs.
- The CDS added 345 kVAC interconnections from Killdeer to Quinn substation in Iowa, and to Lakefield Junction substation in Minnesota.



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#### Exhibit V-2D1: Scenario B: Power from the Prairie HVDC Configuration



The PftP HVDC design features five PftP HVDC converters; one in each state along its span. At least three of these converters (Ault, Central SD/NE, and Raun) would use VSC technology to implement multi-terminal taps of the PftP line as shown. The converters on the ends may be VSC connected back-to-back on the AC side to PftP's counterpart HVDC lines (TransWest and Soo Green). The converter connection to the former has potential to be multi-tap as well, subject to future arrangements with TransWest. This configuration is an estimated starting point and is subject to further refinement and optimization in Stage 2 of the Project.



Exhibit V-2D2: Scenario B: Power from the Prairie HVDC Costs, Converters

#### **Total Incremental Converter Station Costs** (with Multi-Tap at Sinclair) Converter Cost Capacity (MW) Station (2022\$) Sinclair, Wyoming 4,000 \$700,000,000 Move from Sinclair \$--Ault, Colorado Central SD/NE \$685,000,000 3,000 2,000 \$415,000,000 Raun Mason City (PftP) 4,000 \$700,000,000 \$2,500,000,000 Total

Like all other assumptions, these costs are subject to review and optimization during Stage 2 of the Project.



Exhibit V-2D3: Scenario B: PftP HVDC Costs, Overhead Lines



Like all other assumptions, these costs are subject to review and optimization during Stage 2 of the Project.



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#### To Minnesota Power Node A New Renewables 3 GW 52 To PacifiCorp To MISO Node B and Gateway To PJM Soo 155.9 335.2 Green 4 GW PftP HVDC 4 GW 170.45 HVDC Sinclair WY Mason City 4 GW 4 GW 3 GW 97.6 Plano Sub Sub TransWest Chicago Central SD/NE HVDC to Raun Sub Sub (New) Utah Sioux City Ault Sub 93.87 Colorado New HVDC Existing 345 kVAC Node C New 345 kVAC Node D Node E 22.27

Exhibit V-2E1: Scenario B: Power from the Prairie HVAC Configuration

The HVAC transmission additions shown were proposed by the CDS Participants for connection of the PftP HVDC line to their respective systems. Like the PftP HVDC line configuration, these HVAC interconnections are also subject to further refinement and optimization in Stage 2 of the Project.



Line Segment/Station	Length (Miles)	Line	/Station Cost	ROW Land	T	otal (2022\$)	2	2030\$@3%	]	Totals @ 3%
Central Converter - Node B	97.6	\$	497,760,000	\$ 20,703,000	\$	518,463,000	\$	656,773,417		
Node B - Node A	52.5	\$	267,561,000	\$ 11,138,485	\$	278,699,485	\$	353,048,169		
Central Converter							\$	3,868,384		
Node B							\$	7,736,768		
Node A							\$	3,868,384		
Subtotals									\$	1,025,295,122
Central Converter - Node C	98.9	\$	478,737,000	\$ 19,911,800	\$	498,648,800	\$	631,673,381		
Node C - Node D	22.3	\$	66,810,000	\$ 4,723,900	\$	71,533,900	\$	90,617,004		
Central Converter							\$	3,868,384		
Node C							\$	5,802,576		
Node D							\$	1,934,192		
Raun							\$	1,934,192		
Subtotals									\$	735,829,729
Node E - Raun	70	\$	210,000,000	\$ 14,848,500	\$	224,848,500	\$	284,831,353		
Node E							\$	1,934,192		
Raun							\$	1,934,192		
Subtotals									\$	288,699,737
Node E River Crossing							\$	10,000,000		
Central Converter to Node B AC River Crosssing							\$	25,000,000		
									\$	35,000,000.00
Grand Total									Ś	2.084.824.588
									•	_,,

#### Exhibit V-2E2. Scenario B: Power from the Prairie HVAC Costs

Like the other initial assumptions, these HVAC interconnections are also subject to further refinement and optimization in Stage 2 of the Project.



Exhibit V-2F. Scenario C: Gregory County Project Transmission Additions

For Scenario C, all the HVDC and HVAC transmission facilities are already provided by Scenario B.



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Exhibit V-2G1. Scenario D: Minnesota Connection HVDC Configuration





#### Exhibit V-2G2: Scenario E: Minnesota Connection HVDC Conversion Costs

#### Estimated Cost of Conversion without Savings from Existing Facilities

Center, North Dakota Converter	\$ 540,000,000
Adolph, Minnesota Converter	\$ 540,000,000
HVDC Transmission Line, 456 miles	\$1,094,400,000
TOTAL	\$2,174,400,000

#### Estimated Cost of Conversion with Savings from Existing Facilities

Center, North Dakota Converter	\$	540,000,000
Adolph, Minnesota Converter	\$	540,000,000
HVDC Transmission Line, 456 miles	\$1	,094,400,000
TOTAL New Facilities	\$2	,174,400,000

New Facilities	\$2,174,400,000
Savings due to existing facilities	<u>\$ 100,000,000</u>
Total Conversion Cost	\$2,074,400,000

All costs in 2022\$



#### Exhibit V-2G3. Scenario E: Minnesota Connection HVAC Costs

Arrowhead to Rush City	84.4 miles	\$278,520,000
Rush City to Chisago Substation	17.9 miles	\$59,070,000
Chisago Substation to Lake Elmo	34.5 miles	\$90,750,000
Lake Elmo transmission	3.4 miles	\$13,500,000
Lake Elmo to Red Rock Substation	15.3 miles	\$82,620,000

Total

155.5 miles at a cost of \$524,460,000 in 2022\$



Exhibit V-2H: Scenario E+: Utah CAES

For Scenario E, the CAES facility is assumed to be connected at the IPP site HVAC bus. There are minimal additional HVAC facilities involved.

Exhibit V-2I: Scenario E+: Utah H2

For Scenario E+, the hydrogen (H2) electrolyzer facility is assumed to be connected at the IPP site HVAC bus. There are minimal additional HVAC facilities involved.



#### **EXHIBIT V-3. REGIONAL PRODUCTION COSTS, CARBON, AND CURTAILMENT**

#### Exhibit V-3A: Base Case

Base Co	ise											
		Energy (Annual MWh)		Adju	sted Production	Cost, APC (Annual	\$M)	<b>Renewables curtailment</b>	<b>Carbon Emissions</b>	Renewables Facilities		
	Region	Generation	Purchases	Sales	Fuel Cost	Purchase Cost	Sales Revenue Total APC		(Annual MWh)	Annual metric Tons	nual metric Tons Annual Output (MWh) Curtailment (An	
1	MISO	721,454,141	20,865,895	1,547,247	\$ 16,167	\$ 881	\$ 54	\$ 16,995	2,703,964	179,002,619	219,312,628	2,683,769
2	PJM Interconnection	995,387,851	-	54,205,256	\$ 26,468	\$-	\$ 2,131	\$ 24,337	1,315,270	239,675,393	88,936,207	1,226,001
3	SPP	334,031,947	3,674,738	4,934,398	\$ 5,708	\$ 145	\$ 88	\$ 5,765	16,808,747	85,715,693	161,610,092	16,655,511
4	WECC	1,007,982,863	2,902,238	757,801	\$ 19,794	\$ 166	\$ 9	\$ 19,952	4,901,105	170,737,280	318,075,485	3,754,800
5	CA_CISO	217,155,038	31,185,456	4,136,541	\$ 6,122	\$ 2,335	\$ 69	\$ 8,388	568,798	37,807,790	101,090,777	242,322
Totals without double counting CAISO		3,058,856,803	27,442,871	61,444,703	68,138	1,192	2,282	67,048	25,729,086	675,130,984	787,934,412	24,320,080

- The Base Case has total regional Adjusted Production Cost (APC) of more than \$67 Billion, and 675 million metric tons of carbon emissions.
- <u>NOTE</u>: In this table and all subsequent Exhibits V-3:
  - The two right-hand columns show Annual Output and Curtailment for wind and solar renewable energy facilities only.
  - The fourth column from the right shows Renewables Curtailment totals for wind, solar, and hydro facilities.



Scenari	o A											
		Energy (Annual MWh)			Adjusted Production Cost, APC (Annual \$M)				Renewables curtailment	Carbon Emissions	Renewa	bles Facilities
	Region	Generation	Purchases	Sales	Fuel Cost	Purchase Cost	Sales Revenue	Total APC	(Annual MWh)	(Annual metric Tons)	Annual Output (MWh)	Curtailment (Annual MWh)
1	MISO	723,445,670	18,994,972	1,667,091	\$ 16,200	\$ 802	\$ 60	\$ 16,943	2,328,644	179,201,806	219,674,796	2,321,602
2	PJM Interconnection	992,411,175	-	51,208,157	\$ 26,345	\$-	\$ 2,011	\$ 24,334	1,303,917	238,190,768	88,947,559	1,214,649
3	SPP	335,079,712	3,091,605	5,402,557	\$ 5,719	\$ 122	\$ 95	\$ 5,746	16,351,336	86,092,120	162,029,319	16,236,285
4	WECC	1,008,572,315	2,941,160	773,943	\$ 19,074	\$ 167	<u>\$7</u>	\$ 19,234	5,773,846	165,962,426	330,098,797	4,460,935
5	CA_CISO	216,717,558	32,392,463	4,908,143	\$ 5,593	\$ 2,352	\$ 66	\$ 7,879	633,013	35,198,905	111,302,869	244,134
Totals wit	thout double-counting CAISO	3,059,508,872	25,027,736	59,051,748	\$ 67,339	\$ 1,091	\$ 2,173	\$ 66,257	25,757,742	669,447,120	800,750,471	24,233,471
Base Ca	ise											
		Energ	y (Annual MWh		Adjus	sted Production	Cost, APC (Annua	l \$M)	Renewables curtailment	Carbon Emissions	Renewa	bles Facilities
	Region	Generation	Purchases	Sales	Fuel Cost	Purchase Cost	Sales Revenue	Total APC	(Annual MWh)	(Annual metric Tons)	Annual Output (MWh)	Curtailment (Annual MWh)
1	MISO	721,454,141	20,865,895	1,547,247	\$ 16,167	\$ 881	\$ 54	\$ 16,995	2,703,964	179,002,619	219,312,628	2,683,769
2	PJM Interconnection	995,387,851	-	54,205,256	\$ 26,468	\$-	\$ 2,131	\$ 24,337	1,315,270	239,675,393	88,936,207	1,226,001
3	SPP	334,031,947	3,674,738	4,934,398	\$ 5,708	\$ 145	\$ 88	\$ 5,765	16,808,747	85,715,693	161,610,092	16,655,511
4	WECC	1,007,982,863	2,902,238	757,801	\$ 19,794	\$ 166	\$ 9	\$ 19,952	4,901,105	170,737,280	318,075,485	3,754,800
5	CA_CISO	217,155,038	31, 185, 456	4,136,541	\$ 6,122	\$ 2,335	\$ 69	\$ 8,388	568,798	37,807,790	101,090,777	242,322
Totals wit	thout double-counting CAISO	3,058,856,803	27,442,871	61,444,703	\$ 68,138	\$ 1,192	\$ 2,282	\$ 67,048	25,729,086	675,130,984	787,934,412	24,320,080
Scenari	o A change from Base Co	ase										
		Energ	y (Annual MWh		Adjus	sted Production	Cost, APC (Annua	l \$M)	Renewables curtailment	Carbon Emissions	Renewa	bles Facilities
	Region	Generation	Purchases	Sales	Fuel Cost	Purchase Cost	Sales Revenue	Total APC	(Annual MWh)	(Annual metric Tons)	Annual Output (MWh)	Curtailment (Annual MWh)
									-	-	-	-
1	MISO	1,991,529	(1,870,923)	119,844	\$ 33	\$ (79)	\$6	\$ (53)	(375,320)	199,187	362,168	(362,167)
2	PJM Interconnection	(2,976,677)	-	(2,997,099)	\$ (123)	\$-	\$ (121)	\$ (3)	(11,353)	(1,484,625)	11,352	(11,352)
3	SPP	1,047,765	(583,134)	468,158	\$ 11	\$ (23)	\$ 7	\$ (18)	(457,411)	376,427	419,226	(419,226)
4	WECC	589,452	38,921	16,142	<u>\$ (720</u> )	<u>\$ 1</u>	<u>\$ (2</u> )	<u>\$ (717</u> )	872,740	(4,774,854)	12,023,312	706,135
5	CA_CISO	(437,480)	1,207,007	771,602	(529)	17	(4)	(509)	64,214	(2,608,885)	10,212,092	1,812
		-	-	-	-	-	-	-	-	-	-	-
Totals wit	thout double-counting CAISO	652,069	(2,415,135)	(2,392,955)	(799)	(101)	(110)	(791)	28,656	(5,683,865)	12,816,059	(86,609)

#### Exhibit V-3B: Scenario A (Add TransWest Express and Soo Green)

• Scenario A saves \$791 million in regional production costs compared to the Base Case. \$717 million of these savings (or 91%) happen in WECC and are thus attributable to the TransWest Express project. The balance is attributable to Soo Green.

• Carbon emissions decline 5.7 million metric tons. This was the net effect of reductions in WECC (due to the additional TransWest wind energy) and PJM (due to reductions in generation offset by generation imported from MISO), partially offset by increases in economical MISO and SPP fossil generation seeing new markets in PJM via Soo Green.


# Exhibit V-3C. Scenario A+ (Double Soo Green)

Scenari	io A+													
		Energ	gy (Annual MWI	1)	1	Adjus	ted Production	Cost, APC (	(Annual S	\$M)	Renewables curtailment	Carbon Emissions	Renew	ables Facilities
	Region	Generation	Purchases	Sales	Fuel	Cost	Purchase Cost	Sales Rev	venue	Total APC	(Annual MWh)	(Annual metric Tons)	Annual Output (MWh)	Curtailment (Annual MWh)
					1									
1	MISO	724,300,799	18,175,875	1,677,430	\$	16,220	\$ 768	\$	62	\$ 16,926	2,306,301	179,362,107	219,694,661	2,301,737
2	PJM Interconnection	991,255,575	-	50,106,613	\$	26,306	-	\$	1,965	\$ 24,341	1,310,741	237,805,831	88,940,805	1,221,403
3	SPP	335, 332, 766	2,937,205	5,505,888	\$	5,719	\$ 116	\$	96	\$ 5,740	16,196,978	86,189,361	162,166,910	16,098,693
4	WECC	1,008,656,808	2,898,259	781,926	\$	19,077	\$ 165	\$	7	\$ 19,235	5,778,492	166,017,350	330,093,170	4,466,562
5	CA_CISO	216,706,943	32,412,795	4,907,452	\$	5,594	\$ 2,355	\$	66	\$ 7,883	635,168	35,195,712	111,301,175	245,828
Totals wi	thout double-counting CAISO	3,059,545,948	24,011,339	58,071,857	r	67,322	1,049	-	2,130	66,242	25,592,512	669,374,649	800,895,546	24,088,395
							ĺ							
Scenari	io A													
		Energ	gy (Annual MWI	1)	<b></b>	Adjus	ted Production	Cost, APC (	Annual S	\$M)	Renewables curtailment	Carbon Emissions	Renew	vables Facilities
	Region	Generation	Purchases	Sales	Fuel	Cost	Purchase Cost	Sales Rev	venue	Total APC	(Annual MWh)	(Annual metric Tons)	Annual Output (MWh)	Curtailment (Annual MWh)
				i'	1					L				
1	MISO	723,445,670	18,994,972	1,667,091	\$ 16	,200.47	\$ 801.79	\$	60.16	16942.52	2 2,328,644	179,201,806	219,674,796	2,321,602
2	PJM Interconnection	992,411,175	-	51,208,157	\$ 26	,344.75	\$-	\$2,	,010.81	24333.94	1,303,917	238,190,768	88,947,559	1,214,649
3	SPP	335,079,712	3,091,605	5,402,557	\$ 5	,718.93	\$ 122.14	\$	94.70	5746.38	3 16,351,336	86,092,120	162,029,319	16,236,285
4	WECC	1,008,572,315	2,941,160	773,943	\$ 19	,074.36	<u>\$ 166.91</u>	\$	6.89	19234.38	3 5,773,846	165,962,426	330,098,797	4,460,935
5	CA_CISO	216,717,558	32,392,463	4,908,143	\$ 5	,592.94	\$ 2,351.61	\$	65.61	\$ 7,879	633,013	35,198,905	111,302,869	244,134
			L!	L!	L									
Totals wi	thout double-counting CAISO	3,059,508,872	25,027,736	59,051,748	í	67,339	1,091	<u> </u>	2,173	66,257	25,757,742	669,447,120	800,750,471	24,233,471
Scenari	io A+ Change from Scenar	rio A		1										
		Energ	gy (Annual MWI	1)	í	Adjus	ted Production	Cost, APC (	(Annual S	\$M)	Renewables curtailment	Carbon Emissions	Renew	vables Facilities
	Region	Generation	Purchases	Sales	Fuel	Cost	Purchase Cost	Sales Rev	venue	Total APC	(Annual MWh)	(Annual metric Tons)	Annual Output (MWh)	Curtailment (Annual MWh)
				1	1									
1	MISO	855,129	(819,097)	10,339	\$	19.53	\$ (33.79)	\$	1.84	\$ (16.52)	) (22,343)	160,301	19,865	(19,865)
2	PJM Interconnection	(1,155,600)	#VALUE!	(1,101,544)	\$	(38.75)	-	\$	(45.81)	\$ 7.06	6,824	(384,937)	(6,754)	6,754
3	SPP	253,054	(154,400)	103,331	\$	0.07	\$ (6.14)	\$	1.30	\$ (6.38)	) (154,358)	97,241	137,591	(137,592)
4	WECC	84,493	(42,901)	7,983	\$	2.64	\$ (1.91)	\$	0.11	\$ 0.62	4,646	54,924	(5,627)	5,627
5	CA_CISO	(10,614)	20,332	(691)	\$	1.06	\$ 3.39	\$	0.39	\$ 4.05	2,155	(3,193)	(1,694)	1,694
Totals wi	thout double-counting CAISO	37 076	#\/A111F1	(979 891)	¢	(16.51)	Ś (41 84)	ć	(42.56)	Ś (15	(165 230)	(72.471)	145.075	(145.076)

• A hypothetical doubling of the Soo Green project to 4,200 MW saves only \$15 million in production costs and 72,000 metric tons of carbon.



# Exhibit V-3D. Scenario B (Add Power from the Prairie)

Scenar	io B											
		Ei	nergy (Annual MWh	)	Ad	justed Production C	ost, APC (Annual \$M)		Renewables curtailment	Carbon Emissions	Renewab	les Facilities
	Region	Generation	Purchases	Sales	Fuel Cost	Purchase Cost	Sales Revenue	Total APC	(Annual MWh)	(Annual metric Tons)	Annual Output (MWh)	Curtailment (Annual MWh)
1	MISO	739,676,349	16,496,199	3,518,651	\$ 16,423	\$ 686	\$ 124	\$ 16,985	1,768,086	182,500,014	229,582,457	1,761,907
2	PJM Interconnection	993,643,477	-	52,372,736	\$ 26,392	\$-	\$ 2,015	\$ 24,377	1,297,240	238,718,854	88,954,043	1,208,165
3	SPP	328,592,387	6,728,158	2,473,718	\$ 5,406	\$ 257	\$ 42	\$ 5,622	15,767,417	81,488,819	162,591,896	15,673,708
4	WECC	998,562,260	2,595,433	573,295	\$ 18,312	\$ 152	\$ 6	\$ 18,459	3,891,170	159,472,615	331,498,547	3,061,197
5	CA_CISO	215,099,358	34,477,760	5,365,233	\$ 5,406	\$ 2,592	\$ 79	\$ 7,919	402,885	34,401,645	111,369,491	177,512
Totals w	ithout double-counting CAISO	3,060,474,473	25,819,790	58,938,399	\$ 66,533	\$ 1,095	\$ 2,187	\$ 65,442	22,723,913	662,180,301	812,626,943	21,704,977
Scenar	io A											
		E	nergy (Annual MWh	)	Ad	justed Production O	ost, APC (Annual \$M)		Renewables curtailment	Carbon Emissions	Renewab	les Facilities
	Region	Generation	Purchases	Sales	Fuel Cost	Purchase Cost	Sales Revenue	Total APC	(Annual MWh)	(Annual metric Tons)	Annual Output (MWh)	Curtailment (Annual MWh)
1	MISO	723,445,670	18,994,972	1,667,091	\$ 16,200	\$ 802	\$ 60	\$ 16,943	2,328,644	179,201,806	219,674,796	2,321,602
2	PJM Interconnection	992,411,175	-	51,208,157	\$ 26,345	\$-	\$ 2,011	\$ 24,334	1,303,917	238, 190, 768	88,947,559	1,214,649
3	SPP	335,079,712	3,091,605	5,402,557	\$ 5,719	\$ 122	\$ 95	\$ 5,746	16,351,336	86,092,120	162,029,319	16,236,285
4	WECC	1,008,572,315	2,941,160	773,943	\$ 19,074	\$ 167	\$ 7	\$ 19,234	5,773,846	165,962,426	330,098,797	4,460,935
5	CA_CISO	216,717,558	32,392,463	4,908,143	\$ 5,593	\$ 2,352	\$ 66	\$ 7,879	633,013	35,198,905	111,302,869	244,134
Totals w	ithout double-counting CAISO	3,059,508,872	25,027,736	59,051,748	\$ 67,339	\$ 1,091	\$ 2,173	\$ 66,257	25,757,742	669,447,120	800,750,471	24,233,471
Scenar	io B change from Scenario	A										
		Ei	nergy (Annual MWh	)	Ad	justed Production C	ost, APC (Annual \$M)	1	Renewables curtailment	Carbon Emissions	Renewab	les Facilities
	Region	Generation	Purchases	Sales	Fuel Cost	Purchase Cost	Sales Revenue	Total APC	(Annual MWh)	(Annual metric Tons)	Annual Output (MWh)	Curtailment (Annual MWh)
									-	-	-	-
1	MISO	16,230,679	(2,498,773)	1,851,560	\$ 222	\$ (116)	\$ 64	\$ 42	(560,558)	3,298,208	9,907,661	(559,695)
2	PJIVI Interconnection	1,232,302	-	1,164,579	\$ 47	> -	\$ 4	\$ 43	(6,677)	528,086	6,484	(6,484)
3	SPP	(6,487,325)	3,636,553	(2,928,839)	\$ (313)	\$ 135	\$ (53)	\$ (125)	(583,919)	(4,603,301)	562,577	(562,577)
4	WECC	(10,010,054)	(345,727)	(200,648)	<u>\$ (762)</u>	<u>\$ (14)</u>	<u>\$ (1)</u>	<u>\$ (776</u> )	(1,882,675)	(6,489,811)	1,399,750	(1,399,738)
5	CA_CISO	(1,618,200)	2,085,297	457,089	\$ (187)	\$ 240	\$ 14	\$ 40	(230,127)	(797,261)	66,622	(66,622)
		-	-	-	-	-	-	-	-	-	-	-
Totals w	ithout double-counting CAISO	965,601	792,054	(113,348)	\$ (806)	\$ 4	\$ 14	\$ (816)	(3,033,829)	(7,266,819)	11,876,472	(2,528,494)

• Adding PftP reduces regional production costs by \$816 million and regional carbon emissions by 7.3 million metric tons compared to Scenario A.



# Exhibit V-3E. Scenario B+ (Double Soo Green)

Scenar	rio B+ (Double Soo Gre	en)												
		Energy	y (Annual MW	/h)		Adju	sted Production	Cost, APC (Annu	ial \$1	M)	Renewables curtailment	Carbon Emissions	Renewa	bles Facilities
	Region	Generation	Purchases	Sales	Fue	el Cost	Purchase Cost	Sales Revenue	Т	otal APC	(Annual MWh)	(Annual metric Tons)	Annual Output (MWh)	Curtailment (Annual MWh)
1	MISO	740,221,529	15,289,936	3,918,180	\$	16,425	\$ 636	\$ 140	\$	16,922	1,709,091	182,266,144	229,640,095	1,704,268
2	PJM Interconnection	991,748,917	-	50,548,387	\$	26,314	\$-	\$ 1,939	\$	24,375	1,309,358	237,700,188	88,941,894	1,220,313
3	SPP	328,819,498	6,566,249	2,553,845	\$	5,404	\$ 253	\$ 42	\$	5,614	15,580,954	81,532,939	162,759,968	15,505,634
4	WECC	999,635,591	2,607,062	560,933	\$	18,344	\$ 154	\$ 6	\$	18,492	3,807,147	159,956,331	331,561,950	2,997,795
5	CA_CISO	215,168,780	34,451,504	5,396,816	\$	5,408	\$ 2,601	\$ 82	\$	7,927	393,052	34,422,276	111,374,163	172,840
Totals wi	thout double-counting CAISO	3,060,425,534	24,463,247	57,581,345	\$	66,487	\$ 1,043	\$ 2,127	\$	65,403	22,406,550	661,455,603	812,903,907	21,428,011
Scenar	rio B													
		Energy	y (Annual MW	/h)		Adju	sted Production	Cost, APC (Annu	ial \$1	M)	Renewables curtailment	Carbon Emissions	Renewa	bles Facilities
	Region	Generation	Purchases	Sales	Fue	el Cost	Purchase Cost	Sales Revenue	Т	otal APC	(Annual MWh)	(Annual metric Tons)	Annual Output (MWh)	Curtailment (Annual MWh)
1	MISO	739,676,349	16,496,199	3,518,651	\$	16,423	\$ 686	\$ 124	\$	16,985	1,768,086	182,500,014	229,582,457	1,761,907
2	PJM Interconnection	993,643,477	-	52,372,736	\$	26,392	\$-	\$ 2,015	\$	24,377	1,297,240	238,718,854	88,954,043	1,208,165
3	SPP	328,592,387	6,728,158	2,473,718	\$	5,406	\$ 257	\$ 42	\$	5,622	15,767,417	81,488,819	162,591,896	15,673,708
4	WECC	998,562,260	2,595,433	573,295	\$	18,312	\$ 152	\$ 6	\$	18,459	3,891,170	159,472,615	331,498,547	3,061,197
5	CA_CISO	215,099,358	34,477,760	5,365,233	\$	5,406	\$ 2,592	\$ 79	\$	7,919	402,885	34,401,645	111,369,491	177,512
Totals wi	thout double-counting CAISO	3,060,474,473	25,819,790	58,938,399	\$	66,533	\$ 1,095	\$ 2,187	\$	65,442	22,723,913	662,180,301	812,626,943	21,704,977
Scenar	rio B+ changes from So	cenario B												
		Energy	y (Annual MW	/h)		Adju	sted Production	Cost, APC (Annu	ıal \$I	M)	<b>Renewables curtailment</b>	Carbon Emissions	Renewa	bles Facilities
	Region	Generation	Purchases	Sales	Fue	el Cost	Purchase Cost	Sales Revenue	Т	otal APC	(Annual MWh)	(Annual metric Tons)	Annual Output (MWh)	Curtailment (Annual MWh)
1	MISO	545,180	(1,206,263)	399,529	\$	3	\$ (50)	\$ 16	\$	(63)	(58,995)	(233,869)	57,638	(57,638)
2	PJM Interconnection	(1,894,560)	-	(1,824,349)	\$	(78)	\$-	\$ (76)	\$	(2)	12,119	(1,018,665)	(12,149)	12,149
3	SPP	227,110	(161,909)	80,128	\$	(3)	\$ (4)	\$ 1	\$	(7)	(186,463)	44,120	168,073	(168,074)
4	WECC	1,073,330	11,629	(12,362)	\$	32	<u>\$ 1</u>	<u>\$ (0</u> )	\$	33	(84,023)	483,717	63,402	(63,402)
5	CA_CISO	69,422	(26,256)	31,583	\$	2	\$ 9	\$ 3	\$	8	(9,834)	20,631	4,672	(4,672)
Totals wi	thout double-counting CAISO	(48,939)	(1,356,543)	(1,357,054)	\$	(46)	\$ (52)	\$ (59)	\$	(39)	(317,363)	(724,698)	276,964	(276,966)

- Compared to Scenario B, doubling Soo Green to 4,200 MW in Scenario B+ saves only \$39 million in regional production costs and 725,000 metric tons of carbon.
- Like Scenario A+, this is not enough savings to justify an additional \$2.5 Billion in HVDC transmission.



Exhibit V-3F: Scenario C (Add Gregory County Pumped Storage Project)

Scenario C economics are Confidential to the GCPSP Owners, who are CDS Participants.



Scenar	io D											
		Ene	ergy (Annual MW	h)	Adj	usted Production C	ost, APC (Annual \$	M)	Renewables curtailment	Carbon Emissions	Renewal	les Facilities
	Region	Generation	Purchases	Sales	Fuel Cost	Purchase Cost	Sales Revenue	Total APC	(Annual MWh)	(Annual metric Tons)	Annual Output (MWh)	Curtailment (Annual MWh)
												_
1	MISO	741,805,325	15,841,126	4,011,848	\$ 16,193	\$ 657	\$ 138	\$ 16,713	1,729,535	179,380,431	228,491,211	1,721,444
2	PJM Interconnection	992,850,069	-	51,644,576	\$ 26,361	\$-	\$ 1,990	\$ 24,371	1,324,071	238,317,052	88,927,260	1,234,948
3	SPP	328,443,976	6,862,657	2,486,326	\$ 5,400	\$ 260	\$ 42	\$ 5,618	15,783,937	81,234,976	171,927,243	15,686,325
4	WECC	997,659,707	2,607,152	576,110	\$ 18,278	\$ 152	\$ 6	\$ 18,425	3,933,079	159,005,875	332,094,366	3,108,727
5	CA_CISO	214,994,039	34,560,931	5,332,476	\$ 5,400	\$ 2,592	\$ 76	\$ 7,915	407,311	34,365,312	101,153,550	179,549
Totals wi	thout double-counting CAISO	3,060,759,077	25,310,935	58,718,859	\$ 66,233	\$ 1,070	\$ 2,176	\$ 65,127	22,770,622	657,938,334	821,440,080	21,751,444
Scenar	io B											
		Ene	ergy (Annual MW	h)	Adj	usted Production C	ost, APC (Annual \$	M)	Renewables curtailment	Carbon Emissions	Renewał	les Facilities
	Region	Generation	Purchases	Sales	Fuel Cost	Purchase Cost	Sales Revenue	Total APC	(Annual MWh)	(Annual metric Tons)	Annual Output (MWh)	Curtailment (Annual MWh)
1	MISO	739,676,349	16,496,199	3,518,651	\$ 16,422.52	\$ 685.51	\$ 123.75	\$ 16,985	1,768,086	182,500,014	220,234,492	1,761,907
2	PJM Interconnection	993,643,477	-	52,372,736	\$ 26,392.17	\$-	\$ 2,015.30	\$ 24,377	1,297,240	238,718,854	88,954,043	1,208,165
3	SPP	328,592,387	6,728,158	2,473,718	\$ 5,406.31	\$ 256.98	\$ 41.69	\$ 5,622	15,767,417	81,488,819	171,939,860	15,673,708
4	WECC	998,562,260	2,595,433	573,295	\$ 18,311.91	\$ 152.45	\$ 5.86	\$ 18,459	3,891,170	159,472,615	332,128,952	3,074,140
5	CA_CISO	215,099,358	34,477,760	5,365,233	\$ 5,406.12	\$ 2,591.88	\$ 79.31	\$ 7,919	402,885	34,401,645	101,152,807	180,291
Totals wi	thout double-counting CAISO	3,060,474,473	25,819,790	58,938,399	\$ 66,533	\$ 1,095	\$ 2,187	\$ 65,442	22,723,913	662,180,301	813,257,347	21,717,920
Scenar	io D change from Scenario	В										
		Ene	ergy (Annual MW	h)	Adj	usted Production C	ost, APC (Annual \$	M)	Renewables curtailment	Carbon Emissions	Renewal	les Facilities
	Region	Generation	Purchases	Sales	Fuel Cost	Purchase Cost	Sales Revenue	Total APC	(Annual MWh)	(Annual metric Tons)	Annual Output (MWh)	Curtailment (Annual MWh)
									-	-	-	-
1	MISO	2,128,976	(655,073)	493,197	(229)	(28)	14	(272)	(38,551)	(3,119,582)	8,256,719	(40,463)
2	PJM Interconnection	(793,408)	-	(728,160)	(31	-	(25)	(5)	26,831	(401,802)	(26,783)	26,783
3	SPP	(148,411)	134,499	12,608	(6	3	1	(4)	16,521	(253,844)	(12,618)	12,617
4	WECC	(902,554)	11,718	2,814	(34	0	0	(34)	41,909	(466,739)	(34,586)	34,586
5	CA_CISO	(105,319)	83,171	(32,757)	(6	(0)	(3)	(4)	4,426	(36,332)	743	(743)
		-	-	-	-	-	-	-	-	-	-	-
Totals without double-counting CAISO		284,604	(508,855)	(219,540)	(300	(25)	(11)	(314)	46,709	(4,241,967)	8,182,732	33,524

# Exhibit V-3G. Scenario D (Add Minnesota Power Connection)

• The MP Connection saves an additional \$314 million in regional production costs and 4.2 million metric tons of carbon emissions across all regions, compared to Scenario B.



## Exhibit V-3H. Scenario E (Add Utah CAES)

Scenar	io E_Utah CAES											
		Ene	rgy (Annual MV	Vh)	Adju	sted Production C	ost, APC (Annual s	ŝM)	Renewables curtailment	Carbon Emissions	Renewał	oles Facilities
	Region	Generation	Purchases	Sales	Fuel Cost	Purchase Cost	Sales Revenue	Total APC	(Annual MWh)	(Annual metric Tons)	Annual Output (MWh)	Curtailment (Annual MWh)
1	MISO	739,277,056	16,488,359	3,520,949	\$ 16,406	\$ 685	\$ 124	\$ 16,967	1,756,301	182,214,760	229,594,094	1,750,269
2	PJM Interconnection	993,581,152	-	52,322,696	\$ 26,390	\$ -	\$ 2,013	\$ 24,376	1,307,605	238,688,191	88,943,756	1,218,451
3	SPP	328,597,333	6,712,354	2,470,659	\$ 5,406	\$ 256	\$ 41	\$ 5,621	15,764,686	81,425,622	162,592,602	15,673,001
4	WECC	999,005,044	2,554,552	562,240	\$ 18,080	\$ 149	\$ 6	\$ 18,300	3,701,770	158,386,977	335,851,196	2,912,751
5	CA_CISO	214,307,088	35,491,445	5,584,941	\$ 5,339	\$ 2,645	\$ 88	\$ 7,897	379,271	34,070,376	111,374,819	172,184
Totals wi	thout double-counting CAISO	3,060,460,585	25,755,265	58,876,544	\$ 66,282	\$ 1,090	\$ 2,185	\$ 65,264	22,530,362	660,715,550	816,981,649	21,554,473
Scenari	io B											
		Ene	rgy (Annual MV	Vh)	Adiu	sted Production C	ost. APC (Annual S	5M)	Renewables curtailment	Carbon Emissions	Renewał	oles Facilities
	Region	Generation	Purchases	Sales	Fuel Cost	Purchase Cost	Sales Revenue	, Total APC	(Annual MWh)	(Annual metric Tons)	Annual Output (MWh)	Curtailment (Annual MWh)
						1				· · · · · ·		· · · · · ·
1	MISO	739,676,349	16,496,199	3,518,651	\$ 16,423	\$ 686	\$ 124	\$ 16,985	1,768,086	182,500,014	229,582,457	1,761,907
2	PJM Interconnection	993,643,477	-	52,372,736	\$ 26,392	\$ -	\$ 2,015	\$ 24,377	1,297,240	238,718,854	88,954,043	1,208,165
3	SPP	328,592,387	6,728,158	2,473,718	\$ 5,406	\$ 257	\$ 42	\$ 5,622	15,767,417	81,488,819	162,591,896	15,673,708
4	WECC	998,562,260	2,595,433	573,295	\$ 18,312	\$ 152	\$ 6	\$ 18,459	3,891,170	159,472,615	331,498,547	3,061,197
5	CA_CISO	215,099,358	34,477,760	5,365,233	\$ 5,406	\$ 2,592	\$ 79	\$ 7,919	402,885	34,401,645	111,369,491	177,512
							_					
Totals wi	thout double-counting CAISO	3,060,474,473	25,819,790	58,938,399	\$ 66,533	\$ 1,095	\$ 2,187	\$ 65,442	22,723,913	662,180,301	812,626,943	21,704,977
Scenari	io E change from Scenario	В										
		Ene	rgy (Annual MV	Vh)	Adju	sted Production C	Cost, APC (Annual S	5M)	Renewables curtailment	Carbon Emissions	Renewak	oles Facilities
	Region	Generation	Purchases	Sales	Fuel Cost	Purchase Cost	Sales Revenue	Total APC	(Annual MWh)	(Annual metric Tons)	Annual Output (MWh)	Curtailment (Annual MWh)
1	MISO	(399,292)	(7,840)	2,298	(16	(1)	0	(17)	(11 785)	(285 254)	11 637	(11 638)
2	PIMInterconnection	(62.325)	-	(50.040)	(10	-	(2)	(1)	10,366	(30,663)	(10,286)	10,286
3	SPP	4,946	(15,804)	(3,058)	(0	(1)	(2)	(0)	(2.731)	(63.197)	707	(707)
4	WECC	442,783	(40,881)	(11,056)	(232	(3)	0	(159)	(189,400)	(1,085,637)	4,352,649	(148,446)
5	CA CISO	(792,270)	1,013,685	219,708	(67	53	9	(22)	(23,614)	(331,269)	5,328	(5,328)
								. ,		. ,,	-,	(-,,
Totals wi	thout double-counting CAISO	(13,888)	(64,525)	(61,856)	\$ (251	\$ (5)	\$ (2)	\$ (177)	(193,551)	(1,464,751)	4,354,707	(150,504)

- Utah CAES with PftP (Scenario E) saves \$177 million in regional production costs, and 1.5 million metric tons of carbon emissions.
- As expected, due to the location of the project in Utah WECC is by far the biggest beneficiary of these results.



Scenar	rio E+											
	T	Ene	rgy (Annual MW	h)	Adii	usted Production	Cost. APC (Annua	IŚM)	Renewables curtailment	Carbon Emissions	Renewa	bles Facilities
	Region	Generation	Purchases	Sales	Fuel Cost	Purchase Cost	Sales Revenue	Total APC	(Annual MWh)	(Annual metric Tons)	Annual Output (MWh)	Curtailment (Annual MWh)
										1		
1	MISO	739,771,016	16,545,517	3,532,720	16,427	687	124	16,990	1,765,992	182,524,784	229,584,454	1,759,909
2	PJM Interconnection	993,630,619	-	52,377,665	26,391	-	2,015	24,376	1,306,832	238,713,099	88,944,410	1,217,798
3	SPP	328,614,004	6,702,200	2,479,492	5,406	256	42	5,620	15,767,275	81,452,513	162,591,795	15,673,808
4	WECC	998,416,158	2,603,771	567,981	18,380	153	6	18,528	3,883,025	160,028,959	330,082,447	3,056,133
5	CA CISO	215,461,288	34,151,745	5,401,839	5,432	2,575	81	7,925	400,957	34,537,442	111,370,772	176,231
	<u> </u>											1
Totals wi	ithout double-counting CAISO	3,060,431,798	25,851,488	58,957,858	66,604	1,096	2,187	65,514	22,723,124	662,719,354	811,203,106	21,707,648
Scenar	rio B											
		Ene	rgy (Annual MW	h)	Adji	usted Production	Cost, APC (Annua	I\$M)	Renewables curtailment	Carbon Emissions	Renewa	bles Facilities
	Region	Generation	Purchases	Sales	Fuel Cost	Purchase Cost	Sales Revenue	Total APC	(Annual MWh)	(Annual metric Tons)	Annual Output (MWh)	Curtailment (Annual MWh)
1	MISO	739,676,349	16,496,199	3,518,651	\$ 16,423	\$ 686	\$ 124	\$ 16,985	1,768,086	182,500,014	229,582,457	1,761,907
2	PJM Interconnection	993,643,477	-	52,372,736	\$ 26,392	\$-	\$ 2,015	\$ 24,377	1,297,240	238,718,854	88,954,043	1,208,165
3	SPP	328,592,387	6,728,158	2,473,718	\$ 5,406	\$ 257	\$ 42	\$ 5,622	15,767,417	81,488,819	162,591,896	15,673,708
4	WECC	998,562,260	2,595,433	573,295	\$ 18,312	\$ 152	\$ 6	\$ 18,459	3,891,170	159,472,615	331,498,547	3,061,197
5	CA_CISO	215,099,358	34,477,760	5,365,233	\$ 5,406	\$ 2,592	\$ 79	\$ 7,919	402,885	34,401,645	111,369,491	177,512
Totals wi	thout double-counting CAISO	3,060,474,473	25,819,790	58,938,399	\$ 66,533	\$ 1,095	\$ 2,187	\$ 65,442	22,723,913	662,180,301	812,626,943	21,704,977
Scenar	rio E+ changes from Scenario E	3										
		Ene	rgy (Annual MW	h)	Adju	usted Production	Cost, APC (Annua	I\$M)	Renewables curtailment	Carbon Emissions	Renewa	bles Facilities
	Region	Generation	Purchases	Sales	Fuel Cost	Purchase Cost	Sales Revenue	Total APC	(Annual MWh)	(Annual metric Tons)	Annual Output (MWh)	Curtailment (Annual MWh)
												1
1	MISO	94,668	49,318	14,070	\$ 4	\$ 2	\$ 1	\$ 5	(2,094)	24,770	1,997	(1,997)
2	PJM Interconnection	(12,857)	-	4,929	\$ (1)	\$-	\$ (0)	\$ (1)	9,593	(5,755)	(9,633)	9,633
3	SPP	21,617	(25,958)	5,775	\$ 0	\$ (1)	\$ 0	\$ (1)	(142)	(36,306)	(101)	100
4	WECC	(146,103)	8,338	(5,315)	\$ 68	<u>\$ 1</u>	<u>\$ (0</u> )	\$ 69	(8,146)	556,345	(1,416,100)	(5,065)
5	CA_CISO	361,930	(326,015)	36,606	\$ 26	\$ (17)	\$ 2	\$ 7	(1,928)	135,797	1,281	(1,281)
Totals wi	thout double-counting CAISO	(42,675)	31,698	19,458	\$ 72	\$ 1	\$ 1	\$ 72	(789)	539,053	(1,423,837)	2,671

## Exhibit V-3I. Scenario E+ (Add Utah Hydrogen Production)

- In contrast to the other Scenarios, Utah H2 with PftP (Scenario E+) represents an added *load* rather than added renewable generation.
- It results in a regional production cost *increase* of \$72 million in Year 2030, and an increase in annual carbon emissions of about 539,000 metric tons.



# EXHIBIT V-4. CDS PARTICIPANT PRODUCTION COSTS, CARBON, AND CURTAILMENT (CONFIDENTIAL)

This Exhibit V-4 is Confidential to the CDS Participants. It is provided in Volume 3 of this Report for each Participant.



## EXHIBIT V-5. TASK 1: TRANSMISSION FACILITIES PERFORMANCE BY SCENARIO

Exhibit V-5A. Peak MW and MWh Loading, TransWest HVDC



- PftP increases flows on TransWest HVDC in both directions. •
- TWE South-to-North peak flow in Scenario A limited by transformer connection at PacifiCorp, and by lack of other loads to the ٠ North.
- Addition of PftP in Scenario B increases flows South to North by increasing available loads to the North. •
- MP Connection in Scenario D has minimal incremental impact compared to Scenario B. .
- GCPSP (Scenario C) also has minimal incremental impact compared to Scenario B. •
- Utah CAES (Scenario E) with PftP decreases North-to-South flows slightly. .





## Exhibit V-5A. Peak MW and MWh Loading, TransWest HVDC (continued)

- Scenario A hourly flows for year shown. Positive values are North-to-South flows. Negative values are South-to-North.
- TransWest Express (TWE) flows are primarily North-to-South.



### Exhibit V-5B. Peak MW and MWh Loading, TransWest HVAC



- TransWest Express (TWE) HVAC flows are primarily North-to-South, like the TWE HVDC line. ٠
- PftP increases TWE HVAC flows in both directions. .
- MP Connection has no incremental impact on Scenario B (PftP) results. •
- Utah CAES (Scenario E) with PftP has most flows North-to-South. ۲





### Exhibit V-5C. Peak MW and MWh Loading, Soo Green HVDC 2100 MW

- Soo Green is almost exclusively unidirectional, from West-to-East. Base Case has largest energy flows West-to-East. •
- 80% West-to-East capacity factor indicates Soo Green's flow is not just renewable energy.
- Fossil generation output in MISO and SPP increases when Soo Green is added to Base Case.
- PftP (Scenario B) slightly reduces West-to-East flow on Soo Green because it offers new markets to the West for MISO and • SPP generation that would otherwise flow East on Soo Green.
- GCPSP (Scenario C) with PftP has flows similar to Scenario A. •
- Utah H2 (Scenario E+) load with PftP is seen as far east as Soo Green. It decreases West-to-East flow and increases Eastto-West flows.





### Exhibit V-5C. Peak MW and MWh Loading, Soo Green HVDC 2100 MW (continued)

- Scenario A shown. Positive values are West-to-East flows. Negative values are East-to-West. •
- Soo Green flows are primarily unidirectional, from West-to-East (i.e., Iowa to Chicago). ٠



### Exhibit V-5E. Peak MW and MWh Loading, STS HVDC Delta, Utah to So. Cal.



- Flows on the STS are primarily North-to-South, carrying IPP CCTG plant output from Utah to Southern California. ٠
- Scenario A: The TWE HVDC and the 3,300 MW of new wind it enables more than doubles North-to-South energy flows on the STS, and further reduces the already-small South-to-North flows.
- PftP in Scenario B increases N-to-S flows and S-to-N flows, compared to Scenario A. ٠
- GCPSP (Scenario C) with PftP has flows similar to PftP (Scenario B) without GCPSP.
- MP Connection (Scenario D) with PftP has similar flows as PftP without MP Connection.
- Utah CAES (Scenario E) with PftP shows significant additional increases in North-to-South flows.



## Exhibit V-5F. Peak MW and MWh Loading, PftP HVDC, WY to Ault



- PftP (Scenario B) flow between the Ault, CO and Sinclair, WY HVDC converters is bi-directional, with more East-to-West flow due • to the 3,000 MW of new renewables installed in Central SD/NE.
- Initial planning assumption of 4,000 MW capacity of PftP line with 3,000 MW of new renewables in Scenario B performs well, with ٠ minimal clipping.
- PftP flows with MP Connection (Scenario D) essentially the same as Scenario B without MP Connection. •
- Scenario C (Gregory County) with PftP performs well. It accommodates an additional 1,800 MW of renewables at Central SD/NE, • without overloading the PftP line. This is storage acting as a transmission asset.





### Exhibit V-5F. Peak MW and MWh Loading, PftP HVDC, WY to Ault (continued)

- Scenario B shown. Positive values are West-to-East flows. Negative values are East-to-West. ٠
- PftP line between Sinclair, WY and Ault, CO shows directionality West-to-East in first half of year, then East-to-West in second half. •
- Total East-to-West energy flow over the year is larger than West-to-East. ٠





#### Exhibit V-5G. Peak MW and MWh Loading, PftP HVDC, Ault to Center

- PftP (Scenario B) flow between the Central SD/NE and Ault, CO HVDC converters is bi-directional, with more East-to-West energy • flow, due to the 3,000 MW of new renewables installed in Central SD/NE.
- Initial planning assumption of 4,000 MW capacity of PftP line with 3,000 MW of new renewables in Scenario B shows some clipping in the East-to-West direction. The line capacity on this segment was somewhat undersized in the East-to-West direction. This should be examined further in Stage 2 of the Project.
- GCPSP with PftP (Scenario C) performs well. It noticeably accommodates 1,800 MW of additional renewables at the Central converter, but the PftP line is not overloaded. This is storage operating as a transmission asset as well as generation.
  - o GCPSP increases West-to-East flows and decreases East-to-West flows. GCPSP is absorbing more energy from the West.
- PftP flows with MP Connection (Scenario D) very similar to Scenario B without MP Connection, with a small increase in East-to-• West flows.
- Scenarios D, E, and E+ show lower West-to-East flows on this segment of PftP, because they do not have GCPSP in them. Exhibit V-5G. Peak MW and MWh Loading, PftP HVDC, Ault to Center (continued)





- Scenario B shown. Positive values are West-to-East flows. Negative values are East-to-West. •
- PftP line between Ault, CO and Central SD/NE Converter also shows directionality West-to-East in first half of year, then primarily ٠ East-to-West in second half.
- Total East-to-West energy flow over the year is larger than West-to-East.



#### Exhibit V-5H. Peak MW and MWh Loading, PftP HVDC, Central to Raun



- PftP (Scenario B) flow between the Central SD/NE and Raun, IA HVDC converters is bi-directional. •
- Interestingly, although the directional flows are balanced overall, there is more energy flow from Iowa to Central SD/NE, in spite of the 3,000 MW of new renewables installed in Central SD/NE. More energy comes to GCPSP from Iowa than vice versa.
- Assumed PftP 4,000 MW capacity size performs well, with minimal clipping. •
- Addition of Gregory County storage with PftP (Scenario C) increases total energy flows but shifts the direction somewhat West -to-East. GCPSP is acting as a transmission asset by keeping PftP within 4000 MW capacity, while accommodating the additional 1800 MW of renewables at Central SD/NE converter.
- Other than GCPSP, all other Scenarios operate similarly on this PftP line segment. They do not have GCPSP in them. ٠





### Exhibit V-5H. Peak MW and MWh Loading, PftP HVDC, Center to Raun (continued)

- Scenario B shown. Positive values are West-to-East flows. Negative values are East-to-West. ٠
- PftP line between Central SD/NE Converter and Raun (Sioux City) also shows directionality West-to-East in first half of year, then ٠ primarily East-to-West in second half.
- Total East-to-West energy flow over the year is again larger than West-to-East.







- In contrast to the other PftP line segments where flows are bi-directional, flows between Raun (Sioux City) and Mason City are ٠ strongly and almost completely uni-directional West-to-East.
- Raun appears to be a net source of generation in both directions, to the West and to the East. ٠
  - o Flows on the PftP line leaving Raun are larger than those entering from the West. Raun is net injecting energy into PftP.
- Similar to other PftP line segments, addition of GCPSP and 1,800 MW of more renewables to PftP increases total energy flow, ٠ but not peak demands on PftP.
- PftP with MP Connection (Scenario D) has minimal impact on these flows compared to PftP without MP Connection (Scenario B).

Exhibit V-5I. Peak MW and MWh Loading, PftP HVDC, Raun to Mason City (continued)





- Scenario B shown. Positive values are West-to-East flows. Negative values are East-to-West. ٠
- Unlike the other PftP line segments, flows on the PftP line between Raun (Sioux City) and Killdeer (Mason City) are primarily • unidirectional from West-to-East all year.
- Total West-to-East energy flow over the year is much larger than East-to-West. •





#### Exhibit V-5J. PftP HVDC Converter Flows

- From Scenario B, flows into and out of the five HVDC converters are shown. .
- Ault and Sioux City are primarily injecting energy from the AC system into PftP DC line. Central SD/NE and Sinclair both inject • energy into and withdraw energy from PftP. Sinclair is seasonal: AC to DC first half of the year. Then reverses in the latter half of the year.





## Exhibit V-5K. Peak MW and MWh Loading, MP Connection HVDC

- Base Case and Scenarios A and B include this HVDC line at its existing 500 MW capacity. •
  - As expected, flows are primarily West-to-East (i.e., from North Dakota to Minnesota).
- The MP Connection (Scenario D) increases the line capacity to 3000 MW and adds 2,500 MW of new renewables. •
- Greatly increased flows from West-to-East. But capacity factor is only 21%--lower than the renewables added. ٠
  - Basin apparently also benefitting from the development, with some energy from the new renewables going West. 0





#### Exhibit V-5L. Peak MW and MWh Loading, MP Connection HVDC (continued)

- Scenarios B and D shown. Positive values are West-to-East. Negative values are East-to-West. ٠
- In Scenario D, the Square Butte to Arrowhead HVDC line is upgraded form 500 MW to 3,000 MW. .
- Both Scenarios show some East-to-West flows. •



### Exhibit V-5M. Peak MW and MWh Loading, Gateway West HVAC

## Gateway West



- Base Case shows Gateway West heavily East-to-West. ٠
- TransWest (Scenario A) noticeably increases flows West-to-East and decreases flows East-to-West. ٠
- PftP, and Utah CAES and Utah H2 with PftP (Scenarios E and E+), increase East-to-West flows. ٠



### Exhibit V-5N. Peak MW and MWh Loading, Gateway Central HVAC

## Gateway Central



- Gateway Central flows almost completely unidirectional, South-to-North. •
- Other Scenarios starting with Scenario A further increase these South-to-North flows. •
- Utah CAES with PftP (Scenario E) has largest energy flows South-to-North. •



### Exhibit V-50. Peak MW and MWh Loading, Gateway South HVAC

## **Gateway South**



- In Base Case, Gateway South flows are primarily South-to-North. •
- All other Scenarios increase flows to the South and slightly decrease flows to the North. •
- GCPSP with PftP (Scenario C) has largest North-to-South energy flows. Utah CAES with PftP (Scenario E) shows ٠ similar results.





## Exhibit V-5P. Locations of The Back-to-Back HVDC Ties

- The CDS examined flows on HVDC ties crossing the seam between the Western and Eastern Interconnections. Results for the • four highlighted ties are reported on the Exhibits below. The PftP project would be an HVDC overlay on these ties.
- These ties are currently operated on fixed daily schedules. For the CDS, there were allowed to be dispatched by LMP. ٠

**Graphic Source: NREL** 



### Exhibit V-5Q. Peak MW and MWh Loading, Rapid City HVDC Tie



PftP offloads this tie in the East-to-West direction, compared to the Base Case. •

NOTE: The apparent stairstep changes in flows shown for all HVDC ties are a result of simplified, 5-step linear approximation of nonlinear transmission losses in the modeling of the relatively small ties. This is not a characteristic of the tie facilities themselves. More granular, 100-step approximations were used for the larger HVDC lines, which results in a smoother appearance on the LDC graphs for those lines.



#### Exhibit V-5R. Peak MW and MWh Loading, Stegall HVDC Tie



Similar flows on this tie for all Scenarios. •



#### Exhibit V-5S. Peak MW and MWh Loading, Miles City HVDC Tie



- PftP (Scenario B) significantly decreases flows West-to-East on this tie. It increases flows East-to-West slightly. •
- MP Connection added to PftP (Scenario D) accentuates these effects. •
- Utah CAES and H2 (Scenarios E and E+) flows are similar to PftP. ٠



#### Exhibit V-5T. Peak MW and MWh Loading, Sidney HVDC Tie



- PftP (Scenario B) reduces East-to-West flows compared to the Base Case. ٠
- GCPSP added to PftP (Scenario C) further reduces East-to-West flows but increases flows West-to-East. •



## **EXHIBIT V-6. ECONOMIC ANALYSIS INPUT ASSUMPTIONS**

Exhibit V-6A. Financial Assumptions

Parameter	Public Power <sup>1</sup>	Investor-Owned <sup>2</sup>
Debt/Equity Ratio	100%/0%	47%/53%
Weighted Average Cost of Capital (WACC)	5%	8.8%
Levelized annual fixed charge rate for HVDC	5.8%	12.0%

Notes:

1. Applicable to municipals, cooperatives, public power districts, and potential government financing of all kinds.

2. Applicable to for-profit entities including investor-owned utilities and merchant transmission owners. Same fixed charge rate used for public power using hypothetical capital structure for RTO perspective.



LAHIDIL V-OD. FTOJECT CADITAL COSTS AND DEHEITIS DV SCENAL	Exhibit V-6B.	Project Cap	ital Costs and	Benefits by	v Scenario
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	Scenario A		Scenario B	Scenario C	Scenario D	Scenario E	Scenario E+
	Add TransWest	Add Soo Green	Add PftP	Add GCPSP (46 hours)	MP Connection	Utah CAES (48 hours)	Utah H2
Capital Costs (2030 \$Millions)							
Storage	\$ -	\$-	\$-	Confidential	\$ -	\$ 3,086	Calculated
HVDC Line and Converters	\$ 3,000	\$ 2,500	\$ 6,814	Provided by B	\$ 2,074	\$-	Not applicable
AC Interconnections for HVDC	\$ -	\$ 1,374	\$ 2,085	Provided by B	\$ 664	\$-	Not applicable
Additional Renewables	\$ 4,950	\$-	\$ 4,500	\$ 2,700	\$ 3,750	\$ 1,800	\$-
Collector AC Tx for Renewables	\$ 660	<u>\$</u> -	\$ 600	\$ 360	\$ 500	\$ 240	Not applicable
Totals	\$ 8,610	\$ 3,874	\$ 13,999	Confidential	\$ 6,988	\$ 5,126	Calculated
<u>Benefits</u>							
Adjusted Production Costs (APC)	Yes	Yes	Yes	Yes	Yes	Yes	not applicable
Capacity Value of Renewables	Yes	not applicable	Yes	Yes	Yes	Yes	not applicable
Capacity Value of Storage	not applicable	not applicable	not applicable	Yes	not applicable	Yes	not applicable
Enhanced Reliability	in Stage 2	in Stage 2	in Stage 2	in Stage 2	in Stage 2	in Stage 2	in Stage 2
Enhanced Resiliency	in Stage 2	in Stage 2	in Stage 2	in Stage 2	in Stage 2	in Stage 2	in Stage 2
Enhanced Generation Sharing	in Stage 2	in Stage 2	in Stage 2	in Stage 2	in Stage 2	in Stage 2	in Stage 2
Reference for Comparisons	Base Case	Base Case	Scenario A	Scenario B	Scenario B	Scenario B	Scenario B
Additional Renewables Enabled (MW)	3300	0	3000	1800	2500	1200	0
Carbon Reduction (000 metric tons/year)	4,775	909	7,267	1,482	4,242	1,465	(539)

"In Stage 2" denotes benefits to be quantified in Stage 2 of the project.



# Exhibit V-6C. Other Economic Analysis Assumptions

Assumption	Value	<u>Units</u>	Comments
Generic Renewables added with PftP	3,000	MW	
Solar/Wind mix	30%/70%	Mix	energy basis
	1.75/2.00	Mix	capacity basis
Capital cost, solar or wind	\$1,500	per kW	2030\$
Collector tranmission	<u>\$200</u>	per kW	2030\$
Total	\$1,700	Per kW	2030\$
Investment Tax Credits			
Inflation Reduction Act (IRA)			
Renewables or storage	30	%	
If tax-exempt financing.	25.5	%	15% discount of ITC for tax-exempt.
Adder If located on tribal lands	10	%	
Portion on tribal lands	50	%	
Weighed average, Investor, 50% on tribal lands	35	%	
Weighted average, public, tax exempt, 50% of tribal lands.	31	%	15% discount of ITC for tax-exempt.
Proposed for transmission (S.1016, Henrich)			
HVDC and AC transmssion	30	%	S. 1016, Heinrich
Public power eligible?	Yes		Like IRA for renewables and storage
Renewables Annual Capacity Factors			
Wind	44	%	
Solar	22	%	
Effective Load Carrying Capability (ELCC)			
Wind	10	%	Discounted from current 15%
Solar	40	%	Discounted from current 50%
Weighted average at solar/wind mix	24	%	
Hypothetical capital structure			
Debt/equity ratio	50/50	ratio	Similar to an IOU.
Cost of equity			Similar to an IOU.
Avoided capacity cost proxy			
NG fired combustion turbine	\$900	per kW	Cost of New Entry (CONE), 2022\$
Cost of biofuels storage for CT	\$67	per kW	2022\$
Cost escalation rate	3%	per year	


Exhibit V-6D. Production Cost Modeling Data Sources

The CDS modeling Base Case was developed based on "WECC, 2032 Anchor Data Set (ADS) v1.0 Beta" and "MISO/SPP/PJM/SE, MTEP 2030".

The WECC data was updated by 2030 load area peak and energy based on 2018 profile. Included generators to be in-service in 2030.

Additional adjustments included:

- Reference to 2030\$ for WECC and then referenced to the same Henry Hub price for WECC and Eastern Interconnection.
- Used weather year 2018 across entire study to appropriately capture time diversity between renewables and loads. ٠
- Shifted WECC wind/solar hourly load shapes to Eastern Time Zone for consistency with MISO MTEP database. ٠
- MISO Tranche 1 transmission projects are added to Base Case per MISO recommendation. ٠
- Added wheeling rate between WECC and Eastern Interconnection, \$5/MWh wheeling was applied to the inter-ties between East and West.
- Existing HVDC ties between Eastern and Western Interconnections were modeled explicitly.
- Emission price assumption is applied to all regions if the emission price in the supplied model dataset was zero. CO2 national emission price assumed as \$16.07 per metric ton, except California, British Columbia, and Alberta at higher prices that they already assume.
- All wind and utility solar can be curtailed at -\$25/MWh, while Behind-the-Meter (BTM) solar cannot be curtailed. ٠
- WECC oil price replaced by MISO oil price. •
- CDS Participants also provided their inputs for further modifications of the Base Case to reflect their updated views of Year 2030:
  - Updated generation unit additions and retirements.
  - Additional transmission lines and renewables. 0

The Participants' inputs are Confidential to them and are documented in their respective CDS Report Volumes 3.



### **EXHIBIT V-7. ECONOMIC ANALYSIS RESULTS**

#### Exhibit V-7A. Scenario A: TransWest, Investor-Owned, Total Resource Perspective

Scenario A: Add TransWest to the Base Case, Investor Financing, Total Resource Perspective				
Assumptions				
TransWest Express HVDC Line capital cost (\$M)				
Capacity (MW)	3,000	TranWest Express we	ebsite.	
Capital cost (\$M)	\$ 3,000	TranWest Express we	ebsite.	
Fixed O&M (\$/converter, 2022\$)	\$ 650,000	30% labor loading		
Wyoming Power Company wind				
Installed capacity (MW)	3,300	TranWest Express we	ebsite.	
Capital cost (\$/kW)	\$ 1,500			
AC interconnection transmission capital cost (\$/kW)	\$ 200			
ELCC capacity value of wind (% of installed capacity)	10%	Current ELCC of 15%	reduced.	
Inflation Reduction Act Investment Tax credit (% of capital cost)	30%	Inflation Reduction /	Act	
Levelized annual fixed charge rate, Investor-owned (% of installed cost)				
Transmission	12.00%			
Generation	9.40%			
Avoided capacity cost proxy (Cost of New Entry, CONE)				
Capacity cost of new combustion turbine (\$/kW)	\$ 900			
Storage for biofuels for proxy CT (2022 \$/kW)	\$ 67	\$10M per 150 MW of	CT capacity.	
Proposed ITC on HVDC and HVAC transmission lines (% of capital cost)	0%	Sensitivity: Try 30%	per Heinrich bill.	
Cost escalation rate (%/vear)	3%			
Benefit/Cost Analysis (\$M in 2030)				
Transwest Express Project Costs				
Annual investment-related Fixed costs on TransWest Express	\$ 360			
Fixed O&M, TransWest Express DC	\$ 1.6			
Total Annual fixed costs, TWE line		\$ 362		
Annual investment-related fixed costs on TWE enabled renewables	\$ 326			
Annual investment-related cost on AC interconnection Tx for TWE enabled renewables	\$ 79			
Total Annual fixed costs, TWE affiliated renewables		\$ 405		
The set of the set of The The set of the second set			<u>^</u>	767
Iotal Fixed Costs of Twe line and its renewables			\$	/6/
Transwest Express Project Benefits				
Capacity value of new renewables enabled by TWE at ELCC		\$ (38)		
Change in Regional APC compared to Base Case attributable to TWE and its renewables		\$ (717)		
Net Cost (Benefit) of TWE and its affiliate renewables			\$	(755)
Net Benefit/Cost Ratio				0.98
Net Benefit/Cost Ratio with proposed 30% ITC on transmission.				1.15



#### Exhibit V-7B. Scenario A: TransWest, Investor, RTO Perspective

Scenario A: Add TransWest to the Base Case, Investor Financing, RTO Perspect	ive				
Accumations					
TransWest Express HV/DC Line capital cost (\$M)					
Capacity (MMA)		2 000	TranWor	t Exprass wabsita	
Capital sost (\$14)	ć	3,000	TranWas	t Express website.	
Capital Cost (\$141)	ې د	5,000	200/ John	r loading	
Fixed Oalvi (\$/converter, 2022\$)	Ş	650,000	30% IdDO	rioaung	
wyoming Power Company wind					
Installed capacity (MW)		3,300	TranWes	t Express website.	
Capital cost (\$/kW)	Ş	-			
AC interconnection transmission capital cost (\$/kW)	\$	-			
ELCC capacity value of wind (% of installed capacity)		10%	Current E	LCC of 15% reduced.	
Inflation Reduction Act Investment Tax credit (% of capital cost)		30%	Inflation	Reduction Act	
Levelized annual fixed charge rate, Investor-owned (% of installed cost)					
Transmission		12.00%			
Generation		9.40%			
Avoided capacity cost proxy (Cost of New Entry, CONE)					
Capacity cost of new combustion turbine (\$/kW)	\$	900			
Storage for biofuels for proxy CT (2022 \$/kW)	\$	67	\$10M per	r 150 MW of CT capacity.	
Proposed ITC on HVDC and HVAC transmission lines (% of capital cost)		0%	Sensitivity: Try 30% per Heinrich bil		
Cost escalation rate (%/year)		3%			
Benefit/Cost Analysis (\$M in 2030)					
Transwest Express Project Costs					
Annual investment-related Fixed costs on TransWest Express	\$	360			
Fixed O&M, TransWest Express DC	\$	1.6			
Total Annual fixed costs, TWE line			\$ 362		
Annual investment-related fixed costs on TWE enabled renewables	\$	-			
Annual investment-related cost on AC interconnection Tx for TWE $\epsilon$	Ś	-			
Total Annual fixed costs, TWE affiliated renewables	<u> </u>		\$-		
Total Fixed Costs of TWE line and its renewables				\$ 362	
Transwest Express Project Benefits					
Capacity value of new renewables enabled by TWE at ELCC			\$ (38	)	
Change in Regional APC compared to Base Case attributable to TWE	and it	s renewable	\$ (717	)	
Net Cost (Benefit) of TWE and its affiliate renewables				\$ (755	
Net Benefit/Cost Ratio				2.09	
Net Benefit/Cost Ratio with proposed 30% ITC on tra	ansm	ission.		2.98	



### Exhibit V-7C. Scenario A: TransWest, Public Power, Total Resource Perspective

Scenario A: Add TransWest to the Base Case, Public Power, Total Resource Perspective.					
Assumptions					
TransWest Express HVDC Line capital cost (\$M)					
Capacity (MW)		3,000	TransWes	t Express v	vebsite.
Capital cost (\$M)	Ş	3,000	TransWes	t Express v	vebsite.
Fixed O&M (\$/converter, 2022\$)	Ş	650,000	30% labor	loading	
Wyoming Power Company wind					
Installed capacity (MW)		3,300	TransWes	t Express v	vebsite.
Capital cost (\$/kW)	Ş	1,500			
AC interconnection transmission capital cost (\$/kW)	\$	200			
ELCC capacity value of wind (% of installed capacity)		10%	Current E	LCC of 15%	reduced.
Inflation Reduction Act Investment Tax credit (% of capital cost)		25.5%	Inflation	Reduction	Act, tax-exampt financing
Levelized annual fixed charge rate, Public Power, 100% debt financing (% of installed cost)					
Transmission (40 year booklife)		5.83%			
Generation (30 year booklife)		6.51%			
Avoided capacity cost proxy (Cost of New Entry, CONE)					
Capacity cost of new combustion turbine (\$/kW)	\$	900			
Storage for biofuels for proxy CT (2022 \$/kW)	\$	67	\$10M per	150 MW of	CT capacity.
Proposed ITC on HVDC and HVAC transmission lines (% of capital cost)		0%	Sensitivit	y: Try 30%	per Heinrich bill.
Cost escalation rate (%/year)		3%			
Benefit/Cost Analysis (\$M in 2030)					
Transwest Express Project Costs					
Annual investment-related Fixed costs on TransWest Express	\$	175			
Fixed O&M, TransWest Express DC	\$	1.6			
Total Annual fixed costs, TWE line			\$ 176		
Annual investment-related fixed costs on TWE affiliated renewables	\$	240			
Annual investment-related cost on AC interconnection Tx for TWE affiliated renewables	\$	38			
Total Annual fixed costs, TWE affiliated renewables			\$ 278		
Total Fixed Costs of TWE line and its renewables				\$ 455	
Transwest Express Project Benefits					
Capacity value of new renewables enabled by TWE at ELCC			\$ (26)		
Change in Regional APC compared to Base Case attributable to TWE and its renewables			\$ (717)		
Net Cost (Benefit) of TWE and its affiliate renewables				\$ (743)	
Net Benefit/Cost Ratio				1.63	
Net Benefit/Cost Ratio with proposed 30% ITC on transmission.*				1.85	



## Exhibit V-7D. Scenario A: TransWest, Public Power, RTO Perspective Without hypothetical capital structure

Scenario A: Add TransWest to the Base Case, Public Power, RTO Perspective, No Hypothetical Capital Stre	ucture.					
Assumptions						
TransWest Express HVDC Line capital cost (\$M)						
Capacity (MW)		3,000	Trans	Wes	t Express v	vebsite.
Capital cost (\$M)	\$	3,000	Trans	Wes	t Express v	vebsite.
Fixed O&M (\$/converter, 2022\$)	\$	650,000	30% l	abor	loading	
Wyoming Power Company wind						
Installed capacity (MW)		3,300	Trans	Wes	t Express v	vebsite.
Capital cost (\$/kW)	\$	-				
AC interconnection transmission capital cost (\$/kW)	\$	-				
ELCC capacity value of wind (% of installed capacity)		10%	Curre	nt El	LCC of 15%	reduced.
Inflation Reduction Act Investment Tax credit (% of capital cost)		25.5%	Inflat	ion F	Reduction	Act, tax-exampt financing
Levelized annual fixed charge rate, Public Power, 100% debt financing (% of installed cost)						
Transmission (40 year booklife)		5.83%				
Generation (30 year booklife)		6.51%				
Avoided capacity cost proxy (Cost of New Entry, CONE)						
Capacity cost of new combustion turbine (\$/kW)	\$	900				
Storage for biofuels for proxy CT (2022 \$/kW)	\$	67	\$10M	per	150 MW of	CT capacity.
Proposed ITC on HVDC and HVAC transmission lines (% of capital cost)		0%	Sensi	tivit	y: Try 30%	per Heinrich bill.
Cost escalation rate (%/year)		3%				
Benefit/Cost Analysis (\$M in 2030)						
Transwest Express Project Costs						
Annual investment-related Fixed costs on TransWest Express	\$	175				
Fixed O&M, TransWest Express DC	\$	1.6				
Total Annual fixed costs. TWE line			Ś	176		
Annual investment-related fixed costs on TWE affiliated renewables	Ś	-				
Annual investment-related cost on AC interconnection Tx for TWE affiliated renewables	\$	-				
Total Annual fixed costs, TWE affiliated renewables			\$	-		
Total Fixed Costs of TWE line and its renewables					\$ 176	
Transwest Express Project Benefits						
Capacity value of new renewables enabled by TWE at ELCC			\$	(26)		
Change in Regional APC compared to Base Case attributable to TWE and its renewables			\$ (	717)		
Net Cost (Benefit) of TWE and its affiliate renewables				,	\$ (743)	
Net Benefit/Cost Ratio					4.21	
Net Benefit /Cost Ratio with proposed 30% ITC on transmission *					5.99	
*If multis news made aligible for an dit like date in the IDA fearons with the set of the	_				3.33	
In public power made eligible for credit like done in the IKA for renweables and storage.						



## Exhibit V-7D. Scenario A: TransWest, Public Power, RTO Perspective (continued) <u>*With*</u> hypothetical capital structure

Conneria A: Add Translillast to the Pase Case Public Power PTO Perspective Hupotentical Car	ital Chruchura				1	
scenario A. Adu Transwest to the base case, Public Power, KTO Perspective, Hypotentical cap	ntai structure.					
Assumptions						
TransWest Express HVDC Line canital cost (\$M)						
Canacity (MW)	3 (	000	TransWes	t Express v	vehsite	
Capital cost (\$M)	\$ 3(	000	TransWes	t Express v	vebsite	
Fixed Q&M (\$/converter, 2022\$)	\$ 650.0	000	30% Jabor	loading		
Wyoming Power Company wind	+					
Installed capacity (MW)	3.3	300	TransWes	t Express v	vebsite.	
Capital cost (\$/kW)	Ś					
AC interconnection transmission capital cost (\$/kW)	Ś					
ELCC capacity value of wind (% of installed capacity)		10%	Current E	CC of 15%	reduced.	
Inflation Reduction Act Investment Tax credit (% of capital cost)	25	.5%	Inflation Reduction Act, tax-exampt financing			
Levelized annual fixed charge rate. Public Power, 100% debt financing (% of installed cost)						
Transmission (40 year booklife)	12.0	00%				
Generation (30 year booklife)	6.	51%				
Avoided capacity cost proxy (Cost of New Entry, CONE)						
Capacity cost of new combustion turbine (\$/kW)	Ś 9	900				
Storage for biofuels for proxy CT (2022 S/kW)	Ś	67	\$10M per	150 MW of	CT capacity.	
Proposed ITC on HVDC and HVAC transmission lines (% of capital cost)	Con HVDC and HVAC transmission lines (% of capital cost)			v: Trv 30%	per Heinrich bill.	
Cost escalation rate (%/vear)		3%		,		
Benefit/Cost Analysis (ŚM in 2030)		_				
Transwest Express Project Costs						
Annual investment-related Fixed costs on TransWest Express	Ś	360				
Fixed Q&M. TransWest Express DC.	Ś	1.6				
Total Appual fixed costs TW/E line	+		¢ 262			
			Ş 302			
Annual investment-related fixed costs on TWF affiliated renewables	¢	_				
Annual investment-related cost on AC interconnection Tv for TWF affiliated renews	ć	_				
Total Annual fixed costs TWE affiliated renewables	د ب ا	_	ć.			
Total Annual fixed costs, five annuaced reflewables			<b>,</b> -			
Total Fixed Costs of TWF line and its renewables				\$ 362		
				φ 30 <u>2</u>		
Transwest Evnress Project Renefits						
Capacity value of new renewables enabled by TWF at FLCC			\$ (26)			
Change in Regional APC compared to Base Case attributable to TWF and its renewal	bles		\$ (717)			
Net Cost (Benefit) of TWE and its affiliate renewables			- (, 1/)	\$ (743)		
Not Repetit /Cost Patio				2.06		
				2.00		
Net Benefit/Cost Ratio with proposed 30% ITC on transmission.*				2.93		
*If public power made eligible for credit like done in the IRA for renweables and st	orage.					



#### Exhibit V-7E. Scenario A: Soo Green, Investor-Owned, Total Resource Perspective

Scenario A: Add Soo Green to the Base Case, Investor Financing, Total Resource Perspective				
Assumptions				
Soo Green HVDC Line capital cost (\$M)				
Capacity (MW)	2,100	Soo Green we	bsite.	
Capital cost (\$M)	\$ 2,500	Soo Green we	bsite.	
Fixed O&M (\$/converter, 2022\$)	\$ 650,000	30% labor load	ling	
Soo Green AC interconnections				
Capital Cost (\$Min 2030\$)	\$ 1,374	CDS Study Tea	m estimate.	
Enabled Renewables (MW)	-			
Levelized annual fixed charge rate, Public Power (% of installed cost)				
Transmission	9.95%			
Generation	9.40%			
Proposed ITC on HVDCand HVAC transmission lines (% of capital cost)	0%	Sensitivity: Try	30% per Hein	rich bill.
Cost escalation rate (%/year)	3%			
Benefit/Cost Analysis(\$M in 2030)				
Soo Green Project Costs				
Annual investment-related Fixed costs on Soo Green	\$ 249			
Fixed O&M, Soo Green HVDC	\$ 1.6			
Annual investment-related fixed costs on Soo Green AC interconnection lines	\$ 137			
Total Annual fixed costs, TWE line		\$ 387		
Annual investment-related fixed costs on Soo Green enabled renewables	\$ -	ļ		
Total Annual fixed costs, TWE affiliated renewables		\$ -		
Total Fixed Costs of Soo Green line and its renewables			\$ 387	
Can Curner Duniest Demofile				
Soo Green Project Benefits		ć		
Capacity value of new renewables enabled by 500 Green at ELCC				
Not Cost (Ronofit) of TWE and its affiliate renewables		ə (74)	\$ (74)	
Net Cost (benefit) OF TWE drift its driftidte renewables			ş (74)	
Net Benefit/Cost Ratio			0.19	
Net Benefit/Cost Ratio with proposed 30% ITC on transmission			0.27	



#### Exhibit V-7F. Scenario A: Soo Green, Investor-Owned, RTO Perspective

Soo Green has no enabled renewables. So, the Benefit/Cost ratio for the RTO Perspective for Investor-Owned and Public Financials are the same as those shown above for the Total Resource Perspective.



#### Exhibit V-7G. Scenario A: Soo Green, Public Power, Total Resource Perspective

Scenario A: Add Soo Green to the Base Case, Public Power Financing, Total Resource Perspective					
Assumptions					
Soo Green HVDC Line capital cost (\$M)					
Capacity (MW)		2,100	Soo Green w	ebsite.	
Capital cost (\$M)	\$	2,500	Soo Green w	ebsite.	
Fixed O&M (\$/converter, 2022\$)	\$ 6	550,000	30% labor loa	ading	
Soo Green AC interconnections					
Capital Cost (\$M)	\$	1,374	CDS Study Te	am estimate.	
Enabled renewables		-			
evelized annual fixed charge rate, Public Power, 100% debt financing (% of installed cost)					
Transmission		5.83%			
Generation		6.51%			
Proposed ITC on HVDC and HVAC transmission lines (% of capital cost)		0%	Sensitivity: T	ry 30% like IRA	treats storage.
Cost escalation rate (%/year)		3%			
Benefit/Cost Analysis					
Soo Green Project Costs					
Annual investment-related Fixed costs on Soo Green	\$	146			
Fixed O&M, Soo Green HVDC	\$	1.6			
Annual investment-related fixed costs on Soo Green AC interconnection lines	\$	80		-	
Total Annual fixed costs, TWE line			\$ 227		
Annual investment-related fixed costs on Soo Green enabled renewables	Ś	-			
Total Annual fixed costs, TWE enabled renewables	- <del>-</del>		\$-		
Total Fixed Costs of Soo Green line and its enabled renewables				\$ 227	
Soo Green Project Benefits					
Capacity value of new renewables enabled by Soo Green at ELCC			\$-		
Change in Regional APC compared to Base Case attributable to Soo Green and its renewables			\$ (74)		
Net Cost (Benefit) of TWE and its affiliate renewables				\$ (74)	
Net Benefit/Cost Ratio				0.33	
Net Benefit/Cost Ratio with proposed 30% ITC for transmission.*				0.57	
*If public power made eligible for credit like done in the IRA for renweables and storage.					



#### Exhibit V-7H. Scenario A: Soo Green, Public Power, RTO Perspective

Soo Green has no enabled renewables. So, the Benefit/Cost ration for the RTO Perspective for Investor-Owned and Public Financials are the same as those shown above for the Total Resource Perspective.



#### Exhibit V-7I. Scenario B: PftP, Investor-Owned, Total Resource Perspective

Assumptions (All numbers in 20305 unless noted)         PTP HVDC Line capital cost (SM)         4.000         CDS Study Team estimate           Capatry (NW)         4.000         CDS Study Team estimate.         4.000         CDS Study Team estimate.           Capatry (NW)         \$ 3.67         CDS Study Team estimate.         5         3.647         CDS Study Team estimate.           Capital cost, converters only (SM)         \$ 3.667         CDS Study Team estimate.         5         3.647         CDS Study Team estimate.           Fixed OBM (S/converter, 20225)         \$ 6.6000         30% labor loading         PTP AC Interconnection lines added for Scenario B	Scenario B: Add PftP line to Scenario A (with Soo Green at 2100 MW), Investor-owned finacials, Total Res	source Perspective		
assumptions functions functions function         Additions functions functions for the second of	Assumptions (All sumbars is 2020) unless pated)			
Prior Production Capacity (MW)       4,000       CDS Study Team estimate.         Capital cost (SM)       \$ 6,814       CDS Study Team estimate.         Capital cost (SM)       \$ 3,867       CDS Study Team estimate.         Capital cost, DC overhead lines only (SM)       \$ 3,867       CDS Study Team estimate.         Capital cost, DC overhead lines only (SM)       \$ 3,677       CDS Study Team estimate.         PIP AC Interconnection lines added for Scenario B       S       2,085       CDS Study Team estimate (2005)         Central cost (SM)       \$ 2,085       CDS Study Team estimate (2005)       Generic new renewables added with PtP         Installed capacity (MW)       \$ 3,000       CDS Study Team estimate (2005)       Generic new renewables added with PtP         Renewables mix, solar/wind (capacity basis)       1,75/2,00       Current ELCC of 15% and 50% reduced to 10% and 40%, 1.752 solar-wind capacity mix.         Renewables mix, solar/wind (capacity basis)       1,75/2,00       Current ELCC of 15% and 50% reduced to 10% and 40%, 1.752 solar-wind capacity mix.         Inflation Reduction Act Investment Tax credit (% of capital cost)       3%       RA, 50% located on Native American land.         Levelized annual fixed charge rate, Investor-owned (% of installed cost)       12,00%       Current ELCC of 15% and 50% reduced to 10% and 40%, 1.752 solar-wind capacity mix.         Transmission       12,00%       S	Assumptions (All numbers in 20305 unless hoted)			
Capacity (WV)     4,000     Cos Study Team estimate.       Capital cost (SM)     \$ 6,316     COS Study Team estimate.       Capital cost, Coverters only (SM)     \$ 3,367     COS Study Team estimate.       Fixed 0&M (S/converter, 2022)     \$ 650,000     30% labor loading       PTP AC Interconnection lines added for Scenario B	Consister (AdA)	4 000	CDC Chudu Taamaa	timoto
Capital Cost (s/W)     S     6.414     COS study Team estimate.       Capital Cost, converters only (SM)     S     3.467     COS Study Team estimate.       Capital Cost, Converters 2025)     S     650,000     30% labor loading       PHP AC Interconnection lines added for Scenario B     Cost Study Team estimate.     Cost Study Team estimate.       Capital cost (SM)     S     2.085     COS Study Team estimate.       Capital cost (SM)     S     2.085     COS Study Team estimate.       Capital cost (SW)     S     2.008     COS Study Team estimate.       Capital cost (SW)     3.000     CDS Study Team estimate.     Cost Study Team estimate.       Installed capacity (NW)     3.000     CDS Study Team estimate.     Cost Study Team estimate.       Renewables mix, solar/wind (capacity basis)     1.75/2.00     Cost Study Team estimate.       Capital cost (S/KW)     S     1.000     Cost Study Team estimate.       Meighted average ELCC capacity value of renewables (% of total installed capacity)     0.22     Current ELCC of 15% and 50% reduced to 10% and 40%, 1.75.2 solar-wind capacity mix.       Inflation Reduction Act Investment Tax credit (% of capital cost)     12.00%     Capacity cost on New Entry, CONE)       Capacity cost on few combustion turber (2025/kW)     S     900       Storage or biolueis for proxy C1 (2022 k/kW)     S     500	Capacity (MW)	4,000	CDS Study Team es	sumate
Capital cost, converters only (SM) Capital cost, Converters only (SM) Fixed O&M (\$/converter, 2022) Source the submate. Capital cost (SM) Cost Study Team estimate (20305) Capital cost (SM) Capital cost (S/M) Capital cost (\$/M) Current ELCC of 15% and 50% reduced to 10% and d0%, 1.75/2.00 Current ELCC of 15% and 50% reduced to 10% and d0%, 1.75/2.30 Current ELCC of 15% and 50% reduced to 10% and d0%, 1.75/2.30 Current ELCC of 15% and 50% reduced to 10% and d0%, 1.75/2.30 Current ELCC of 15% and 50% reduced to 10% and d0%, 1.75/2.30 Current ELCC of 15% and 50% reduced to 10% and d0%, 1.75/2.30 Current ELCC of 15% and 50% reduced to 10% and d0%, 1.75/2.30 Current ELCC of 15% and 50% reduced to 10% and d0%, 1.75/2.30 Current ELCC of 15% and 50% reduced to 10% and d0%, 1.75/2.30 Current ELCC of 15% and 50% reduced to 10% and d0%, 1.75/2.30 Current ELCC of 15% and 50% reduced to 10% and d0%, 1.75/2.30 Current ELCC of 15% and 50% reduced to 10% and d0%, 1.75/2.30 Current ELCC of 15% and 50% reduced to 10% and d0%, 1.75/2.30 Current ELCC of 15% and 50% reduced to 10% and d0%, 1.75/2.30 Current ELCC of 15% and 50% reduced to 10% and d0%, 1.75/2.30 Current ELCC of 15% and 50% reduced to 10% and d0%, 1.75/2.30 Current ELCC of 15% and 50% reduced to 10% and d0%, 1.75/2.30 Current ELCC of 15% and 50% reduced to 10% and d0%, 1.75/2.30 Current ELCC of 15% and 50% reduced to 10% and d0%, 1.75/2.30 Current ELCC of 15% and 50% reduced to 10% and d0%, 1.75/2.30 Current ELCC of 15% and 50% reduced to 10% Current ELCC of 15% and 50% reduced to 10% Current ELCC of 15%	Capital cost (SM)	\$ 6,814	CDS Study Team es	stimate.
Capital Cost, DC Verification Resource (Source Filter Cost)       \$ 5,047       Cost Study Team estimate.         Fixed ORK (Sconverter, 2025)       \$ 0,050,000       30%       COS Study Team estimate (2005)         Capital cost (SM)       3,000       CDS Study Team estimate (2005)       CDS Study Team estimate (2005)         Generic new renewables added with PftP       3,000       CDS Study Team estimate (2005)       CDS Study Team estimate (2005)         Renewables mix, solar/wind (energy basis)       3,000       CDS Study Team estimate       CDS Study Team estimate (2005)         Capital cost (S/kW)       \$ 1,500       Corrent ELCC of 15% and 50% reduced to 10% and 40%, 1.75; 20 and 50% reduced to 10% and 50% reduced	Capital cost, converters only (\$M)	\$ 3,167	CDS Study Team es	stimate.
Pixed USM (Sychowerter, 2022)       \$       ego.00       3/6 labor leading         PIPA CLiterconnection lines added for Scenario B	Capital cost, DC overhead lines only (SM)	\$ 3,047	CDS Study Team es	sumate.
PtP AC Interconnection lines added for Scenario B       Cost Study Team estimate (2030\$)         Capital cost (\$M)       \$ 2,085       COS Study Team estimate (2030\$)         Generic new renewables added with PftP       3,000       CDS Study Team estimate (2030\$)         Renewables mix, solar/wind (energy basis)       3,000       CDS Study Team estimate (2030\$)         Renewables mix, solar/wind (capacity basis)       1,75/2.00       Capital cost (\$/kW)         AC interconnection transmission capital cost (\$/kW)       \$ 2,000       Current ELCC of 15% and 50% reduced to 10% and 40%, 1,75:2 solar-wind capacity mix.         Inflation Reduction Act investment Tax credit (% of capital cost)       35%       IA, 50% located on Native American land.         Levelized annual fixed charge rate, investor-owned (% of installed cost)       12,00%       Capacity cost proxy (Cost of New Entry, CONE)         Capacity cost proxy (Cost of New Entry, CONE)       9,40%       \$ 500       Storage for biofuels for proxy CT (2022 \$/kW)         Storage for biofuels for proxy CT (2022 \$/kW)       \$ 600       \$ 500       Storage reneintric bill.         Cost escalation rate       3%       Sensitivity: Try 30% per Heinrich bill.       Sensitivity: Try 30% per Heinrich bill.         Cost escalation rate       3%       S 520       Storage for biofuels for proxy CT (2022 \$/kW)       \$ 600         Prower from the Praine Project Costs       \$ 3.3 <td>Fixed O&amp;M (\$/converter, 2022\$)</td> <td>\$ 650,000</td> <td>30% labor loading</td> <td></td>	Fixed O&M (\$/converter, 2022\$)	\$ 650,000	30% labor loading	
Capital cost (SM)       \$ 2.085       CDS Study Team estimate (20305)         Generic new reewables added with PtP       3,000       CDS Study Team estimate         Renewables mix, solar/wind (energy basis)       30%/70%       CDS Study Team estimate         Renewables mix, solar/wind (energy basis)       30%/70%       S       CDS Study Team estimate         Capital cost (S/kW)       \$ 1,75/2.00       Current ELCC of 15% and 50% reduced to 10% and 40%, 1.75/2.20 solar.wind capacity mix.         Inflation Reduction Act Investment Tax credit (% of total installed capacity)       0.24       Current ELCC of 15% and 50% reduced to 10% and 40%, 1.75/2.20 solar.wind capacity mix.         Inflation Reduction Act Investment Tax credit (% of capital cost)       250%       Current ELCC of 15% and 50% reduced to 10% and 40%, 1.75/2.20 solar.wind capacity mix.         Inflation Reduction Act Investment Tax credit (% of capital cost)       355%       IRA, 50% located on Native American land.         Levelized annual fixed charge rate, Investor-owned (% of installed cost)       12.00%       Generation       9.40%         Avoided capacity cost proxy (Cost of New Entry, CONE)       9       9       Storage for biofuls for proxy (C1 (2022 S/kW)       \$ 900         Cost escalation rate       3%       9       Storage for biofuls for proxy (C1 (2022 S/kW)       \$ 67       \$ 10M per 150 MW of CT capacity.         Proposed ITC on HVDC and HVAC transmission lines (% of	PftP AC Interconnection lines added for Scenario B			
Generation ew renewables added with PtP       3,000       CDS Study Team estimate         Installed capacity (MW)       3,000       CDS Study Team estimate         Renewables mix, solar/wind (energy basis)       11.75/2.00          Capital cost (5/KW)       \$ 1,500          AC interconnection transmission capital cost (5/KW)       \$ 200          Meighted average ELCC capacity value of renewables (% of total installed capacity)       0.24       Current ELCC of 15% and 50% reduced to 10% and 40%, 1.75.2 solar.wind capacity mix.         Inflation Reduction Act Investment Tax credit (% of capital cost)       35%       IRA, 50% located on Native American land.         Levelized annual fixed charge rate, Investor-owned (% of installed cost)       9.40%           Transmission       9.40%            Avoided capacity cost proxy (Cost of New Entry, CONE)       9.40%           Capacity cost for ew combustion turbine (20225/kW)       \$ 500            Storage for biofuels for proxy CT (2022 5/kW)       \$ 500            Cost scalation rate       3%              Renewables for proxy CT (2022 5/kW)       \$ 67       \$L0M per 150 MW of CT capacity.	Capital cost (\$M)	\$ 2,085	CDS Study Team es	timate (2030\$)
Installed capacity (MW)       3,000       CDS Study Team estimate         Renewables mix, solar/wind (capacity basis)       30%/70%       30%/70%         Capital cost (S/kW)       \$1,75/2.00       1.75/2.00         AC interconnection transmission capital cost (S/kW)       \$200       0.24         Weighted average ELCC capacity value of renewables (% of total installed capacity)       \$200       0.24         Inflation Reduction Act Investment Tax credit (% of capital cost)       35% IRA, 50% located on Native American land.         Inflation Reduction Act Investment Tax credit (% of capital cost)       35%       IAA, 50% located on Native American land.         Inflation Reduction Act Investment Tax credit (% of capital cost)       35%       IAA, 50% located on Native American land.         Inflation Reduction Act Investment Tax credit (% of capital cost)       35%       IAA, 50% located on Native American land.         Inflation Reduction Act Investment Tax credit (% of capital cost)       35%       IAA, 50% located on Native American land.         Inflation Reduction Act Investment Tax credit (% of capital cost)       9.40%       12.00%       Image: Second Common Comm	Generic new renewables added with PftP			
Renewables mix, solar/wind (energy basis)       30%/70%         Renewables mix, solar/wind (capacity basis)       1.75/2.00         Capital cost (5/kW)       \$ 1,500         AC interconnection transmission capital cost (\$/kW)       \$ 200         AC interconnection transmission capital cost (\$/kW)       \$ 200         Weighted average ELCC capacity value of renewables (% of total installed capacity)       0.24       Current ELCC of 15% and 50% reduced to 10% and 40% 1.75:2 solar-wind capacity mix.         Inflation Reduction Act Investment Tax credit (% of capital cost)       35%       IRA, 50% located on Native American land.         Levelized annual fixed charge rate, Investor-owned (% of installed cost)       12.00%       Transmission       12.00%         Generation       9.40%       9.40%       Storage for biofuels for proxy (Cost of New Entry, CONE)       Storage for biofuels for proxy C1 (2022 \$/kW)       \$ 900         Storage for biofuels for proxy C1 (2022 \$/kW)       \$ 67       \$10M per 150 MW of CT capacity.         Proposed ITC on HVDC and HVAC transmission lines (% of capital cost)       0%       Sensitivity: Try 30% per Heinrich bill.         Cost escalation rate       3%       S       Sensitivity: Try 30% per Heinrich bill.         Annual investment-related fixed costs of PftP DC line       \$ 818       Inflation Reduction in the store on Actinerconnection lines         Annual investment-related fixed costs o	Installed capacity (MW)	3,000	CDS Study Team es	stimate
Renewables mix, solar/wind (capacity basis)       1.75/2.00         Capital cost (\$/kW)       \$ 1,500         AC interconnection transmission capital cost (\$/kW)       \$ 200         Weighted average ELCC capacity value of renewables (% of total installed capacity)       0.24       Current ELCC of 15% and 50% reduced to 10% and 40%, 1.75:2 solar:wind capacity mix.         Inflation Reduction Act Investment Tax credit (% of capital cost)       35%       IRA, 50% located on Native American land.         Levelized annual fixed charge rate, Investor-owned (% of installed cost)       12.00%          Transmission       94.00%          Generation       9.40%          Avoided capacity cost of new combustion turbine (2022\$/kW)       \$ 67       \$10M per 150 MW of CT capacity.         Storage for biofuels for proxy CT (2022 \$/kW)       \$ 67       \$10M per 150 MW of CT capacity.         Storage for biofuels for proxy CT (2022 \$/kW)       \$ 67       \$10M per 150 MW of CT capacity.         Cost escalation rate       3%           Remet//Cost Analysis (SM in 2030)       \$ 33           Power from the Prainte Project Costs       \$ 3.3           Annual investment-related fixed costs on PftP AC interconnection lines       \$ 3.3           Fixed 0&M on PftP HVDC and AC transmission	Renewables mix, solar/wind (energy basis)	30%/70%		
Capital cost (\$/kW)       \$       1,500         AC interconnection transmission capital cost (\$/kW)       \$       200         Weighted average ELCC capacity value of renewables (% of total installed capacity)       0.24       Current ELCC of 15% and 50% reduced to 10% and 40%, 1.75:2 solar:wind capacity mix.         Inflation Reduction Act Investment Tax credit (% of capital cost)       35% IRA, 50% located on Native American land.         Levelized annual fixed charge rate, Investor-owned (% of installed cost)       12.00%         Transmission       12.00%         Generation       9.40%         Avoided capacity cost proxy (Cost of New Entry, CONE)       10.00%         Capacity cost of new combustion turbine (2022\$/kW)       \$       900         Storage for biofuels for proxy CT (2022 \$/kW)       \$       5         Proposed ITC on HVDC and HVAC transmission lines (% of capital cost)       0%       \$         Cost excalation rate       3%       100         Manual investment-related fixed costs of PftP DC line       \$       818         Fixed O&M on PftP HVDC line       \$       3.3         Annual investment-related fixed costs on PftP AC interconnection lines       \$       1,071         Manual investment-related fixed costs on PftP AC interconnection lines       \$       1,071         Annual investment-related fixed costs on PftP AC intercon	Renewables mix, solar/wind (capacity basis)	1.75/2.00		
AC interconnection transmission capital cost (\$/kW)       \$ 200         Weighted average ELCC capacity value of renewables (% of total installed capacity)       0.24       Current ELCC of 15% and 50% reduced to 10% and 40%, 1.75:2 solar:wind capacity mix.         Inflation Reduction Act Investment Tax credit (% of capital cost)       33%       IRA, 50% located on Native American land.         Levelized annual fixed charge rate, Investor-owned (% of installed cost)       33%       IRA, 50% located on Native American land.         Inflation Reduction Act Investment Tax credit (% of capital cost)       33%       IRA, 50% located on Native American land.         Investment Tax credit (% of capital cost)       33%       IRA, 50% located on Native American land.         Investment Tax credit (% of capital cost)       940%       12.00%       100         Generation       9.40%       940%       100       100         Avoided capacity cost proxy (Cost of New Entry, CONE)       940%       100       100       100         Capacity cost of new combustion turbine (2022\$/kW)       \$ 67       \$10M per 150 MW of CT capacity.       100         Proposed ITC on HVDC and HVAC transmission lines (% of capital cost)       03%       Sensitivity: Try 30% per Heinrich bill.       100         Cost escalation rate       3%       100       100       100       100       100       100       100       100 </td <td>Capital cost (\$/kW)</td> <td>\$ 1,500</td> <td></td> <td></td>	Capital cost (\$/kW)	\$ 1,500		
Weighted average ELCC capacity value of renewables (% of total installed capacity)       0.24       Current ELCC of 15% and 50% reduced to 10% and 40%, 1.75:2 solar:wind capacity mix.         Inflation Reduction Act Investment Tax credit (% of capital cost)       35%       IRA, 50% located on Native American land.         Iverant ELCC of 15% and 50% reduced to 10% and 40%, 1.75:2 solar:wind capacity mix.       35%       IRA, 50% located on Native American land.         Iverant ELCC of 15% and 50% reduced to 10% of installed cost)       35%       IRA, 50% located on Native American land.         Iverant ELCC of 15% and 50% reduced to 10% of installed cost)       12.00%       12.00%       12.00%         Generation       9.40%       900       12.00%       12.00%       12.00%         Avoided capacity cost proxy (Cost of New Entry, CONE)       900       10.00%       12.00%	AC interconnection transmission capital cost (\$/kW)	\$ 200		
Inflation Reduction Act Investment Tax credit (% of capital cost)       35% IRA, 50% located on Native American land.         Levelized annual fixed charge rate, Investor-owned (% of installed cost)       12.00%         Transmission       12.00%         Generation       9.40%         Avoided capacity cost proxy (Cost of New Entry, CONE)       9.40%         Capacity cost of new combustion turbine (2022\$/kW)       \$ 900         Storage for biofuels for proxy CT (2022 \$/kW)       \$ 67         Proposed ITC on HVDC and HVAC transmission lines (% of capital cost)       0%         Sensitivity: Try 30% per Heinrich bill.       Cost escalation rate         Benettif/Cost Analysis (\$M in 2030)       9         Power from the Praine Project Costs       9         Annual investment-related fixed costs on PftP DC line       \$ 818         Fixed 0&M on PftP HVDC line       \$ 1,071         Annual investment-related fixed costs on PftP AC interconnection lines       \$ 275         Annual investment-related fixed costs on PftP-enabled generic renewables       \$ 275         Annual investment-related fixed costs on AC interconnection Tx for PftP-enabled renewables       \$ 275         Total Annual investment-related fixed costs on AC interconnection Tx for PftP-enabled renewables       \$ 347	Weighted average ELCC capacity value of renewables (% of total installed capacity)	0.24	Current ELCC of 15 40%, 1.75:2 solar:w	% and 50% reduced to 10% and vind capacity mix.
Levelized annual fixed charge rate, Investor-owned (% of installed cost)       Image: Cost of	Inflation Reduction Act Investment Tax credit (% of capital cost)	35%	IRA, 50% located o	n Native American land.
Transmission       12.00%         Generation       9.40%         Avoided capacity cost of New Entry, CONE)       9.40%         Capacity cost of new combustion turbine (2022\$/kW)       \$ 900         Storage for biofuels for proxy CT (2022 \$/kW)       \$ 900         Storage for biofuels for proxy CT (2022 \$/kW)       \$ 67         Storage for biofuels for proxy CT (2022 \$/kW)       \$ 67         Storage for biofuels for proxy CT (2022 \$/kW)       \$ 67         Storage for biofuels for proxy CT (2022 \$/kW)       \$ 67         Storage for biofuels for proxy CT (2022 \$/kW)       \$ 67         Storage for biofuels for proxy CT (2022 \$/kW)       \$ 67         Storage for biofuels for proxy CT (2022 \$/kW)       \$ 67         Storage for biofuels for proxy CT (2022 \$/kW)       \$ 67         Storage for biofuels for proxy CT (2022 \$/kW)       \$ 67         Storage for biofuels for proxy CT (2022 \$/kW)       \$ 67         Storage for biofuels for proxy CT (2022 \$/kW)       \$ 67         Storage for biofuels for proxy CT (2022 \$/kW)       \$ 67         Storage for biofuels for proxy CT (2022 \$/kW)       \$ 67         Storage for biofuels for proxy CT (2022 \$/kW)       \$ 67         Power form the Praint Propert Costs       \$ 77         Annual investment-related fixed costs on PftP DC line       \$ 1,071	Levelized annual fixed charge rate, Investor-owned (% of installed cost)			
Generation     9.40%       Avoided capacity cost proxy (Cost of New Entry, CONE)     Image: Control of New Entry, CONE)       Capacity cost of new combustion turbine (2022\$/kW)     \$ 900       Storage for biofuels for proxy CT (2022 \$/kW)     \$ 67       Storage for biofuels for proxy CT (2022 \$/kW)     \$ 67       Proposed ITC on HVDC and HVAC transmission lines (% of capital cost)     0%       Sensitivity: Try 30% per Heinrich bill.       Cost escalation rate     3%       Benetif/Cost Analysis (\$M in 2030)     Image: Cost Sensitivity: Try 30%       Power from the Prairie Project Costs     Image: Cost Sensitivity: Try 30%       Annual investment-related fixed costs of PftP DC line     \$ 818       Fixed 0&M on PftP HVDC line     \$ 3.3       Annual investment-related fixed costs on PftP AC interconnection lines     \$ 250       Total Annual investment-related fixed costs on PftP-enabled generic renewables     \$ 1,071       Annual investment-related fixed costs on PftP-enabled generic renewables     \$ 275       Annual investment-related fixed costs on AC interconnection Tx for PftP-enabled renewables     \$ 347	Transmission	12.00%		
Avoided capacity cost proxy (Cost of New Entry, CONE)       Image: Cost of new combustion turbine (2022\$/kW)       \$ 900         Storage for biofuels for proxy CT (2022 \$/kW)       \$ 67       \$10M per 150 MW of CT capacity.         Proposed ITC on HVDC and HVAC transmission lines (% of capital cost)       0%       Sensitivity: Try 30% per Heinrich bill.         Cost escalation rate       3%       Image: Cost cost cost cost cost cost cost cost c	Generation	9.40%		
Capacity cost of new combustion turbine (2022\$/kW)       \$ 900         Storage for biofuels for proxy CT (2022 \$/kW)       \$ 67         Proposed ITC on HVAC transmission lines (% of capital cost)       0%         Sensitivity: Try 30% per Heinrich bill.         Cost escalation rate       3%         Benetif/Cost Analysis (\$M in 2030)       3%         Power from the Prairie Project Costs       4         Annual investment-related fixed costs of PftP DC line       \$ 818         Fixed 0&M on PftP HVDC Ine       \$ 3.3         Annual investment-related fixed costs on PftP AC interconnection lines       \$ 250         Total Annual investment-related fixed costs on PftP-enabled generic renewables       \$ 275         Annual investment-related fixed costs on AC interconnection Tx for PftP-enabled renewables       \$ 275         Total Annual investment-related fixed costs on AC interconnection Tx for PftP-enabled renewables       \$ 347	Avoided capacity cost proxy (Cost of New Entry, CONE)			
Storage for biofuels for proxy CT (2022 \$/kW)       \$       67       \$10M per 150 MW of CT capacity.         Proposed ITC on HVDC and HVAC transmission lines (% of capital cost)       0%       Sensitivity: Try 30% per Heinrich bill.         Cost escalation rate       3%	Capacity cost of new combustion turbine (2022\$/kW)	\$ 900		
Proposed ITC on HVDC and HVAC transmission lines (% of capital cost)     O%     Sensitivity: Try 30% per Heinrich bill.       Cost escalation rate     3%       Benetif/Cost Analysis (\$M in 2030)     3%       Power from the Prairie Project Costs     4       Annual investment-related fixed costs on PftP DC line     \$ 818       Fixed O&M on PftP HVDC line     \$ 3.3       Annual investment-related fixed costs on PftP AC interconnection lines     \$ 250       Total Annual investment-related fixed costs on PftP-enabled generic renewables     \$ 1,071       Annual investment-related fixed costs on PftP-enabled generic renewables     \$ 275       Annual investment-related cost on AC interconnection Tx for PftP-enabled renewables     \$ 347	Storage for biofuels for proxy CT (2022 \$/kW)	\$ 67	\$10M per 150 MW	of CT capacity.
Cost escalation rate     3%       Benetif/Cost Analysis (\$M in 2030)     3%       Power from the Prairie Project Costs     4       Annual investment-related fixed costs of PftP DC line     \$ 818       Fixed 0&M on PftP HVDC line     \$ 3.3       Annual investment-related fixed costs on PftP AC interconnection lines     \$ 250       Total Annual investment-related fixed costs on PftP-enabled generic renewables     \$ 275       Annual investment-related fixed costs on PftP-enabled renewables     \$ 72       Total Annual investment-related fixed costs on AC interconnection Tx for PftP-enabled renewables     \$ 347	Proposed ITC on HVDC and HVAC transmission lines (% of capital cost)	0%	Sensitivity: Trv 30%	6 per Heinrich bill.
Benetif /Cost Analysis (SM in 2030)     Image: Second	Cost escalation rate	3%		
Benetify/Cost Analysis (SM in 2030)     Image: SM in 2030)       Power from the Prairie Project Costs     Image: SM in 2030)       Annual investment-related fixed costs of PftP DC line     \$ 818       Fixed 0&M on PftP HVDC line     \$ 3.3       Annual investment-related fixed costs on PftP AC interconnection lines     \$ 250       Total Annual investment-related fixed costs on PftP AC interconnection lines     \$ 1,071       Image: Cost of the Province of the Provi	Break (Constanting) (At the 2020)			
Annual investment-related fixed costs of PftP DC line     \$ 818       Fixed 0&M on PftP HVDC line     \$ 3.3       Annual investment-related fixed costs on PftP AC interconnection lines     \$ 250       Total Annual fixed costs, PftP DC and AC transmission lines     \$ 1,071       Annual investment-related fixed costs on PftP-enabled generic renewables     \$ 275       Annual investment-related cost on AC interconnection Tx for PftP-enabled renewables     \$ 72       Total Annual fixed costs, PftP generic renewables     \$ 347	Benetif/Cost Analysis (SM in 2030)			
Annual investment-related inxed costs or PtP DL line     \$     \$18       Fixed O&M on PtP HVDC line     \$     3.3       Annual investment-related fixed costs on PtP AC interconnection lines     \$     250       Total Annual investment-related fixed costs on PtP. enabled generic renewables     \$     1,071       Annual investment-related fixed costs on PtP-enabled generic renewables     \$     275       Annual investment-related cost on AC interconnection Tx for PtP-enabled renewables     \$     72       Total Annual fixed costs, PtP generic renewables     \$     347	Power from the Praine Project Costs	ć 040		
Fixed OakMon PTCP HVDC line     \$ 3.3       Annual investment-related fixed costs on PftP AC interconnection lines     \$ 250       Total Annual fixed costs, PftP DC and AC transmission lines     \$ 1,071       Annual investment-related fixed costs on PftP-enabled generic renewables     \$ 275       Annual investment-related cost on AC interconnection Tx for PftP-enabled renewables     \$ 72       Total Annual fixed costs, PftP generic renewables     \$ 347	Annual Investment-related fixed costs of PTCP DC line	\$ 818		
Annual investment-related fixed costs on PTP AC interconnection lines     \$ 250       Total Annual fixed costs, PftP DC and AC transmission lines     \$ 1,071       Annual investment-related fixed costs on PftP-enabled generic renewables     \$ 275       Annual investment-related cost on AC interconnection Tx for PftP-enabled renewables     \$ 72       Total Annual fixed costs, PftP generic renewables     \$ 347	Fixed U&M on PTTP HVDC line	\$ 3.3		
Initial Annual fixed costs, PftP DC and AC transmission lines     \$ 1,0/1       Annual investment-related fixed costs on PftP-enabled generic renewables     \$ 275       Annual investment-related cost on AC interconnection Tx for PftP-enabled renewables     \$ 72       Total Annual fixed costs, PftP generic renewables     \$ 347	Annual Investment-related fixed costs on PTTP AC Interconnection lines	\$ 250	4 4 974	
Annual investment-related fixed costs on PftP-enabled generic renewables     \$ 275       Annual investment-related cost on AC interconnection Tx for PftP-enabled renewables     \$ 72       Total Annual fixed costs, PftP generic renewables     \$ 347	Iotal Annual fixed costs, PTP DC and AC transmission lines		\$ 1,0/1	
Annual investment-related cost on AC interconnection Tx for PftP-enabled renewables     \$ 72       Total Annual fixed costs, PftP generic renewables     \$ 347	Annual investment-related fixed costs on PftP-enabled generic renewables	\$ 275		
Total Annual fixed costs, PftP generic renewables \$ 347	Annual investment-related cost on AC interconnection Tx for PftP-enabled renewables	\$ 72		
	Total Annual fixed costs, PftP generic renewables		\$ 347	
Total Fixed Costs of PftP line and its renewables \$ 1,418	Total Fixed Costs of PftP line and its renewables			\$ 1,418
Power from the Prairie Project Benefits	Power from the Prairie Project Benefits			
Capacity value of new renewables enabled by PftP at ELCC \$ (83)	Capacity value of new renewables enabled by PftP at ELCC		\$ (83)	
Change in Regional APC compared to Scenario A attributable to PftP and renewables \$ (816)	Change in Regional APC compared to Scenario A attributable to PftP and renewables		\$ (816)	
Net Cost (Benefit) of PftP and its generic renewables \$ (899)	Net Cost (Benefit) of PftP and its generic renewables			\$ (899)
Net Benefit/Cost Ratio 0.63	Net Benefit/Cost Ratio			0.63
Benefit/Cost Batio with proposed 30% ITC for HVDC and HVAC transmission	Benefit /Cost Batio with proposed 30% ITC for HVDC and HVAC transmisison			0.82



## Exhibit V-7J. Scenario B: PftP, Investor-Owned, RTO Perspective

Scenario B: Add PftP line to Scenario A (with Soo Green at 2100 MW), Investor-ov	<u>wned finacials, RT</u>	O Perspect	ive
Assumptions (All numbers in 2030\$ unless noted)			
PftP HVDC Line capital cost (\$M)			
Capacity (MW)	4 000	CDS Study	Team estimate
Capital cost (ŚM)	\$ 6.814	CDS Study	Team estimate.
Capital cost, converters only (\$M)	\$ 3.167	CDS Study	Team estimate.
Capital cost, DC overhead lines only (SM)	\$ 3.647	CDS Study	Team estimate.
Fixed O&M (\$/converter, 2022\$)	\$ 650,000	30% labor	loading
PftP AC Interconnection lines added for Scenario B			_
Capital cost (ŚM)	\$ 2.085	CDS Study	Team estimate (2030\$)
Generic new renewables added with PftP	,		
Installed capacity (MW)	3,000	CDS Study	Team estimate
Renewables mix, solar/wind (energy basis)	30%/70%		
Renewables mix, solar/wind (capacity basis)	1.75/2.00		
Capital cost (\$/kW)	\$ -		
AC interconnection transmission capital cost (\$/kW)	\$-		
Weighted average ELCC capacity value of renewables (% of total installed ca	0.24	Current El	CC of 15% and 50% reduced to
Inflation Reduction Act Investment Tax credit (% of capital cost)	35%	IRA, 50% I	ocated on Native American land.
Levelized annual fixed charge rate, Investor-owned (% of installed cost)			
Transmission	12.00%	i la	
Generation	9.40%		
Avoided capacity cost proxy (Cost of New Entry, CONE)			
Capacity cost of new combustion turbine (2022\$/kW)	\$ 900		
Storage for biofuels for proxy CT (2022 \$/kW)	\$ 67	\$10M per	150 MW of CT capacity.
Proposed ITC on HVDC and HVAC transmission lines (% of capital cost)	0%	Sensitivity	y: Try 30% per Heinrich bill.
Cost escalation rate	3%		
Panatif/Cast Analysis (\$M in 2020)			
Benerify Cost Analysis (Sin III 2000)			
Annual investment related fixed costs of BftB DC line	ć 010		
Fixed QRM on RftR HVDC line	¢ 22		
Annual investment related fixed costs on DftD AC interconnection lines	\$ 5.5 ¢ 250		
Total Appual fixed costs . PftP DC and AC transmission lines	Ş 230	\$ 1.071	
Total Annual fixed costs, FTF DC and AC transmission mes		Ş 1,071	
Annual investment-related fixed costs on PftP-enabled generic renewables	Ś -		
Annual investment-related cost on AC interconnection Tx for PftP-enabled r	s -		
Total Annual fixed costs. PftP generic renewables	<u> </u>	Ś -	
		Ŷ	
Total Fixed Costs of PftP line and its renewables		-	\$ 1.071
Power from the Prairie Project Benefits			
Capacity value of new renewables enabled by PftP at ELCC		\$ (83)	
Change in Regional APC compared to Scenario A attributable to PftP and ren	ewables	\$ (816)	
Net Cost (Benefit) of PftP and its generic renewables		1	\$ (899)
Net Benefit/Cost Ratio			0.84
Benefit/Cost Batio with proposed 30% ITC for HVDC and HV	/ AC transmisis	on	1 20
benefity cost natio with proposed solo ne for hybe and hy	rie transmisis	0.1	1.20



### Exhibit V-7K. Scenario B, Public Power, Total Resource Perspective

Assumptions (All numbers in 2030 unless noted) PHP HVDC Line capital cost (SM) Capacity (MM) Capital cost (SM) Capital cost (SM) Capital cost, converters only (SM) Fixed O&M (S/converter, 2022) PHP AC Interconnection lines added for Scenario B Capital cost (SM) Capital cost (SM) Capital cost (SM) Solow (SK) Capital cost (SM) Capital cost (SM) Solow (SK) Capital cost (SM) Solow (SK) Capital cost (SM) Solow (SK) Capital cost (SM) Solow (SK) Capital cost (SM) Capital cost (SM) Renewables mix, solar/wind (capacity basis) AC interconnection lines added with PtP Installed capacity (MW) Solow (Capacity basis) AC interconnection transmission capital cost (S/kW) AC interconnection transmission capital cost (S/kW) Solow (Capital cost (Capital cost) Capacity cost of New Entry, CONE) Capacity cost of New Entry, CONE) Capacity cost of New Cost of New Entry, CONE) Capacity cost of New Cost of Cost (Cost (Capital cost) Capacity cost of New Cost of Cost (Cost (Cost of PfP DC line Animal investment related (ixed costs of PfP DC line Solow (Cost of New Entry) Cost of New Entry (Cost of PfP DC line Solow (Cost of New Entry) Cost of PfP DC line Solow (Cost of New Entry) Cost of PfP DC li
Assumptions (All numbers in 20305 unless noted) Assumptions (All numbers in 20305 unless noted) (PtP HVDC Line capital cost (SM) Capital cost, Converters only (SM) Capital cost, Converters only (SM) Capital cost, Converters only (SM) Salar CDS Study Team estimate Capital cost, CD inters only (SM) Salar CDS Study Team estimate Capital cost, CD inters only (SM) Capital cost, CD inters only (SM) Salar CDS Study Team estimate Capital cost, CD inters only (SM) Salar CDS Study Team estimate Capital cost, CD inters only (SM) Salar CDS Study Team estimate Capital cost, CD inters only (SM) Salar CDS Study Team estimate Capital cost (SM) Cost Study Team estimate Capital cost (SM) Cost Study Team estimate Capital cost (SM) CDS Study Team estimate Capital cost (SM) Cost Study Team estimate Capital cost (SM) Cost Study Team estimate Capital cost (S/kW) Salar Cost Study Team estimate Capital cost (S/kW) Current ELCC of 15% and 50% reduced to 10% and 40%, 1.75:2 Current ELCC of 15% and 50% reduced to 10% and 40%, 1.75:2 Current ELCC of 15% and 50% reduced to 10% and 40%, 1.75:2 Current ELCC of 15% and 50% reduced to 10% and 40%, 1.75:2 Current ELCC of 15% and 50% reduced to 10% and 40%, 1.75:2 Current ELCC of 15% and 50% reduced to 10% and 40%, 1.75:2 Current ELCC of 15% and 50% reduced to 10% and 40%, 1.75:2 Current ELCC of 15% and 50% reduced to 10% and 40%, 1.75:2 Current ELCC construction ITC due to tax-exampt financing, 50% locate con Native American Iand. Current Capacity cost on rew combustion turbine (2025/kW) Cost exclasion rate (%/year)
PHP HVDC Line capital cost (SM)       4         Capacity (MW)       4,000         Capital cost, Converters only (SM)       \$         Fixed 0&M (S/converter, 2025)       \$         Capital cost, CSM       \$         Capital cost, SM/ (Fam estimate       \$         Renewables mix, solar/wind (eapacity basis)       \$         Capital cost (S/kW)
Capadity (MW)       4,000       CDS Study Team estimate         Capital cost, (SM)       \$       6,614       CDS Study Team estimate         Capital cost, Converters only (SM)       \$       3,647       CDS Study Team estimate         Capital cost, DC lines only (SM)       \$       6,614       CDS Study Team estimate         Capital cost, DC lines only (SM)       \$       6,600,000       30% labor loading         PHP AC Interconnection lines added for Scenario B       CDS Study Team estimate       CDS Study Team estimate         Capital cost, (SM)       \$       2,085       CDS Study Team estimate         Capital cost (SM)       \$       2,085       CDS Study Team estimate         Capital cost (SM)       \$       2,000       CDS Study Team estimate         Capital cost (SM)       \$       3,000       CDS Study Team estimate         Renewables mix, solar/wind (energy basis)       30%/70%       \$       1,75/2.00         Capital cost (S/W)       \$       1,500       Current ELCC of SW and S0% reduced to 10% and 40%, 1.75:2         Veighted average ELCC capacity value of renewables (% of total installed capacity)       0.424       colar:wind capacity mix.         Inflation Reduction Act Investment Tax credit (% of capital cost)       5       333%       Current ELCC of SW and S0% reduced to 10% and 40%, 1.75:2
Capital cost (SM)       \$ 5,614       CDS Study Team estimate         Capital cost, converters only (SM)       \$ 3,647       CDS Study Team estimate         Capital cost, converters only (SM)       \$ 3,647       CDS Study Team estimate         Fixed 0&M (S/converter, 2022S)       \$ 650,000       30% labor loading         PIP AC Interconnection lines added for Scenario B       CDS Study Team estimate       CDS Study Team estimate         Capital cost, (SM)       \$ 2,085       CDS Study Team estimate       CDS Study Team estimate         Generic new renewables added with PfP       3,000       CDS Study Team estimate       CDS Study Team estimate         Renewables mix, solar/wind (capacity basis)       1,75/2.00       CDS Study Team estimate       CDS Study Team estimate         Renewables mix, solar/wind (capacity basis)       1,75/2.00       Current ELCC of 15% and 50% reduced to 10% and 40%, 1.75.2         Capital cost (S/kW)       \$ 1,500       Current ELCC of 15% and 50% reduced to 10% and 40%, 1.75.2         weighted average ELCC capacity value of renewables (% of total installed capacity)       0.24       current ELCC of 15% and 50% reduced to 10% and 40%, 1.75.2         Inflation Reduction Act Investment Tax credit (% of capital cost)       313%       Generation       5.83%         Avoided capacity cost of new combuston turbine (2025/kW)       \$ 6.51%       Sorage for biofuels for proxy Clost of New Entr
Capital cost, converters only (SM)       \$ 3,167       CDS Study Team estimate         Capital cost, DC lines only (SM)       \$ 3,647       CDS Study Team estimate         Fixed O&M (S/converter, 2025)       \$ 660,000       30% labor loading         PftP AC Interconnection lines added for Scenario B       \$ 2,085       CDS Study Team estimate         Capital cost (SM)       \$ 2,085       CDS Study Team estimate         Capital cost (SM)       \$ 3,000       CDS Study Team estimate         Installed capacity (IMW)       3,000       CDS Study Team estimate         Renewables mix, solar/wind (energy basis)       30%/70%         Renewables mix, solar/wind (capacity basis)       1.75/2.00         Capital cost (S/W)       \$ 2,005         AC interconnection transmission capital cost (S/kW)       \$ 2,005         Weighted average ELCC capacity value of renewables (% of total installed capacity)       0.24         Urrent ELCC of 15% and 50% reduced to 10% and 40%, 1.75:2       solar-wind capacity mix.         Inflation Reduction Act Investment Tax credit (% of capital cost)       31%         Transmission       5.38%         Generation       6.51%         Avoided capacity cost of New combustion turbine (2025/kW)       \$ 900         Storage for biofuels for proxy CT (2022 S/kW)       \$ 67         Storage for biofu
Capital cost, DC lines only (SM)       \$ 3,647       CDS Study Team estimate         Fixed ORM (S/converter, 2025)       \$ 650,000       30% labor loading         PftP AC Interconnection lines added for Scenario B       CDS Study Team estimate (2005)         Capital cost (SM)       \$ 2,085       CDS Study Team estimate (2005)         Generic new renewables added with PftP       0       0         Installed capacity (MW)       3,000       CDS Study Team estimate (2005)         Renewables mix, solar/wind (capacity basis)       1.75/2.00       0         Capital cost (S/kW)       \$ 1,500       0         AC interconnection transmission capital cost (S/kW)       \$ 1,500       0         Weighted average ELCC capacity value of renewables (% of total installed capacity)       0.24       Current ELCC of 15% and 50% reduced to 10% and 40%, 1.75:2         value daverage ELCC capacity value of renewables (% of total installed capacity)       0.24       Current ELCC of 15% and 50% reduced to 10% and 40%, 1.75:2         value daverage table charge rate, Investor-owned (% of installed cost)       31%       RA, 15% discount on ITC due to tax-exampt financing, 50% locate on Native American land.         Level ized annual fixed charge rate, Investor-owned (% of capital cost)       5       83%       0         Generation       5.83%       6       6       0         Avoided capacity
Fixed O&M (s/converter, 2025)       \$ 650,000       30% labor loading         PftP AC Interconnection lines added for Scenario B       5       2,085       CDS Study Team estimate (20305)         Generic new renewables added with PftP       3,000       CDS Study Team estimate (20305)         Installed capacity (MW)       3,000       CDS Study Team estimate         Renewables mix, solar/wind (energy basis)       30%/70%         Capital cost (S/W)       \$ 1,550         Capital cost (S/W)       \$ 1,500         Capital cost (S/W)       \$ 200         AC interconnection transmission capital cost (S/kW)       \$ 200         Weighted average ELCC capacity value of renewables (% of total installed capacity)       0.24         Inflation Reduction Act Investment Tax credit (% of capital cost)       31%         Inflation Reduction Act Investment Tax credit (% of sintalled cost)       31%         Transmission       5.83%         Generation       6.51%         Avoided capacity cost of New Entry, CONE)       5         Capatize Cost of NUV of CT capacity.       \$ 900         Storage for bioluels for proxy C1 (2022 S/kW)       \$ 67         Storage for bioluels for proxy C1 (2022 S/kW)       \$ 67         Storage for bioluels for proxy C1 (2022 S/kW)       \$ 67         Storage for bioluels for proxy C1 (2
PftP AC Interconnection lines added for Scenario B       CDS Study Team estimate (20305)         Capital cost (\$M)       \$ 2,085         CDS Study Team estimate (20305)       CDS Study Team estimate (20305)         Renewables mix, solar/wind (energy basis)       3000         Capital cost (\$/KW)       \$ 1,570         Capital cost (\$/KW)       \$ 1,570         Capital cost (\$/KW)       \$ 1,570         AC interconnection transmission capital cost (\$/KW)       \$ 1,570         AC interconnection transmission capital cost (\$/KW)       \$ 200         Weighted average ELCC capacity value of renewables (% of total installed capacity)       0.24         Inflation Reduction Act Investment Tax credit (% of capital cost)       31%         Inflation Reduction Act Investment Tax credit (% of installed cost)       \$ 83%         Generation       6.51%         Avoided capacity cost proxy (Cost of New Entry, CONE)       \$ 900         Storage for biofuels for proxy (C1 (202 \$/KW)       \$ 900         Storage for biofuels for proxy (C1 (202 \$/KW)       \$ 900         Storage for biofuels for proxy (C1 (202 \$/KW)       \$ 900         Storage for biofuels for proxy (C1 (202 \$/KW)       \$ 900         Storage for biofuels for proxy (C1 (202 \$/KW)       \$ 900         Storage for biofuels for proxy (C1 (202 \$/KW)       \$ 900
Capital cost (SM)       \$ 2,088       CDS Study Team estimate (2030\$)         Generic new renewables added with PftP       3,000       CDS Study Team estimate (2030\$)         Installed capacity (MW)       3,000       CDS Study Team estimate         Renewables mix, solar/wind (energy basis)       30%/70%         Renewables mix, solar/wind (capacity basis)       1.75/2.00         Capital cost (S/kW)       \$ 1,500         AC interconnection transmission capital cost (S/kW)       \$ 200         Weighted average ELCC capacity value of renewables (% of total installed capacity)       0.24         Unflation Reduction Act Investment Tax credit (% of capital cost)       31%         Inflation Reduction Act Investment Tax credit (% of installed cost)       18A, 15% discount on ITC due to tax-exampt financing, 50% locate on Native American land.         Investigation Cost of New Entry, CONE)       5       31%         Capacity cost of New Entry, CONE)       5       500         Capacity cost of new combustion turbine (20225/kW)       \$ 900       5         Storage for biofuels for proxy CT (2022 \$/kW)       \$ 67       510M per 150 MW of CT capacity.         Proposed ITC on HVDC and HVAC transmission lines (% of capital cost)       0%       5       50         Benefit/Cost Analysis (SM in 2030)       7       7       7         Power from the Praile Proj
Generic new renewables added with PftP       3,000       CDS Study Team estimate         Installed capacity (MW)       30%/70%       30%/70%         Renewables mix, solar/wind (capacity basis)       1.75/2.00       1.75/2.00         Capital cost (\$/kW)       \$ 1,500       200         AC interconnection transmission capital cost (\$/kW)       \$ 200       Current ELCC of 15% and 50% reduced to 10% and 40%, 1.75:2         Weighted average ELCC capacity value of renewables (% of total installed capacity)       0.24       Current ELCC of 15% and 50% reduced to 10% and 40%, 1.75:2         Inflation Reduction Act Investment Tax credit (% of capital cost)       31%       RA, 15% discount on ITC due to tax-exampt financing, 50% locate on Native American land.         Levelized annual fixed charge rate, investor-owned (% of installed cost)       Inflation Reduction Act Investment Tax credit (% of capital cost)       Inflation (2022 f/kW)         Generation       5.83%       Generation       6.51%         Avoided capacity cost proxy (Cost of New Entry, CONE)       5       900         Storage for biofuels for proxy CT (2022 f/kW)       \$ 900       Sensitivity: Try 30% per proposed ITC bill (S.1016, Henrich)         Cost escalation rate (%/year)       3%       Sensitivity: Try 30% per proposed ITC bill (S.1016, Henrich)         Cost escalation rate (%/year)       3%       Sensitivity: Try 30% per proposed ITC bill (S.1016, Henrich)
Installed capacity (MW)       3,000       CDS Study Team estimate         Renewables mix, solar/wind (capacity basis)       30%/70%       30%/70%         Capital cost (\$/kW)       \$ 1,75/2.00       1.75/2.00         AC interconnection transmission capital cost (\$/kW)       \$ 200       Current ELCC of 15% and 50% reduced to 10% and 40%, 1.75:2 solar:wind capacity mix.         Weighted average ELCC capacity value of renewables (% of total installed capacity)       0.24       Current ELCC of 15% and 50% reduced to 10% and 40%, 1.75:2 solar:wind capacity mix.         Inflation Reduction Act Investment Tax credit (% of capital cost)       31%       IRA, 15% discount on ITC due to tax-exampt financing, 50% locate on Native American land.         Levelized annual fixed charge rate, Investor-owned (% of installed cost)       Inflation Reduction Act Investment Tax credit (% of capital cost)       IRA, 15% discount on ITC due to tax-exampt financing, 50% locate on Native American land.         Levelized annual fixed charge rate, Investor-owned (% of installed cost)       Inflation Reduction Act Investment Tax credit (% of capital cost)       Inflation Cost for the cost for
Renewables mix, solar/wind (energy basis)       30%/70%         Renewables mix, solar/wind (capacity basis)       1.75/2.00         Capital cost (5/kW)       \$ 1,500         AC interconnection transmission capital cost (5/kW)       \$ 200         Weighted average ELCC capacity value of renewables (% of total installed capacity)       0.24         Inflation Reduction Act Investment Tax credit (% of capital cost)       31%         Inflation Reduction Act Investment Tax credit (% of capital cost)       31%         Irransmission       5.83%         Generation       5.83%         Generation       6.51%         Avoided capacity cost proxy (Cost of New Entry, CONE)       6.51%         Capacity cost of new combustion turbine (2022\$/kW)       \$ 900         Storage for biofuels for proxy CT (2022 \$/kW)       \$ 900         Storage for biofuels for proxy CT (2022 \$/kW)       \$ 100 kpc r150 km of CT capacity.         Proposed ITC on HVDC and HVAC transmission lines (% of capital cost)       0%         Storage for biofuels for proxy CT (2022 \$/kW)       \$ 900         Storage for biofuels for proxy CT (2022 \$/kW)       \$ 900         Storage for biofuels for proxy CT (2022 \$/kW)       \$ 900         Cost escalation rate (%/year)       3%         Benefit/Cost Analysis (SM in 2030)       Power from the Prainte Project Costs
Renewables mix, solar/wind (capacity basis)       1.75/2.00         Capital cost (\$/kW)       \$ 1,500         AC interconnection transmission capital cost (\$/kW)       \$ 200         Weighted average ELCC capacity value of renewables (% of total installed capacity)       0.24       Current ELCC of 15% and 50% reduced to 10% and 40%, 1.75:2 solar:wind capacity mix.         Inflation Reduction Act Investment Tax credit (% of capital cost)       31%       RA, 15% discount on ITC due to tax-exampt financing, 50% locate on Native American land.         Levelized annual fixed charge rate, Investor-owned (% of installed cost)       5.83%       6         Transmission       5.83%       6         Generation       6.51%       7         Avoided capacity cost proxy (Cost of New Entry, CONE)       5       500         Capacity cost of new combustion turbine (2022\$/kW)       \$ 900       5         Storage for biofuels for proxy CT (2022 \$/kW)       \$ 900       5         Cost escalation rate (%/year)       3%       6         Benefit/Cost Analysis (\$M in 2030)       7       7         Power from the Prainte Project Costs       7       7         Annual investment-related fixed costs of PftP DC line       \$ 397       7
Capital cost (\$/kW)       \$ 1,500         AC interconnection transmission capital cost (\$/kW)       \$ 200         Weighted average ELCC capacity value of renewables (% of total installed capacity)       0.24       Current ELCC of 15% and 50% reduced to 10% and 40%, 1.75:2 solar:wind capacity mix.         Inflation Reduction Act Investment Tax credit (% of capital cost)       31%       IRA, 15% discount on ITC due to tax-exampt financing, 50% locate on Native American land.         Levelized annual fixed charge rate, Investor-owned (% of installed cost)       8.33%       Image: Comparison on the comparison on
AC interconnection transmission capital cost (\$/kW)       \$ 200         Weighted average ELCC capacity value of renewables (% of total installed capacity)       0.24       Current ELCC of 15% and 50% reduced to 10% and 40%, 1.75:2 solar:wind capacity mix.         Inflation Reduction Act Investment Tax credit (% of capital cost)       IRA, 15% discount on ITC due to tax-exampt financing, 50% locate on Native American land.         Levelized annual fixed charge rate, Investor-owned (% of installed cost)       IRA, 15% discount on ITC due to tax-exampt financing, 50% locate on Native American land.         Capacity cost proxy (Cost of New Entry, CONE)       5       6         Capacity cost proxy (Cost of New Entry, CONE)       5       900         Storage for biofuels for proxy CT (2022 \$/kW)       \$ 900       5         Yerposed ITC on HVDC and HVAC transmission lines (% of capital cost)       0%       Sensitivity: Try 30% per proposed ITC bill (S.1016, Henrich)         Cost escalation rate (%/year)       3%       900       900       900         Demertic/Cost Analysis (SM in 2030)       937       937       937         Prover from the Prainte Project Costs       937       937       937
Weighted average ELCC capacity value of renewables (% of total installed capacity)       0.24       Current ELCC of 15% and 50% reduced to 10% and 40%, 1.75:2         solar:wind capacity mix.       solar:wind capacity mix.       RA, 15% discount on ITC due to tax-exampt financing, 50% locate on Native American land.         Levelized annual fixed charge rate, Investor-owned (% of installed cost)       ransmission       5.83%         Transmission       5.83%       6         Generation       6.51%       Avoided capacity cost proxy (Cost of New Entry, CONE)         Capacity cost of new combustion turbine (2022\$/kW)       \$ 900       5         Storage for biofuels for proxy CT (2022 \$/kW)       \$ 5       510M per 150 MW of CT capacity.         Proposed ITC on HVDC and HVAC transmission lines (% of capital cost)       0%       \$ sensitivity: Try 30% per proposed ITC bill (S.1016, Henrich)         Cost escalation rate (%/year)       3%       1       1         Benefit/Cost Analysis (\$M in 2030)       9       1       1         Power from the Prainte Project Costs       937       1       1         Annual investment-related fixed costs of PftP DC line       \$ 397       1       1
Inflation Reduction Act Investment Tax credit (% of capital cost)       IRA, 15% discount on ITC due to tax-exampt financing, 50% locate on Native American land.         Levelized annual fixed charge rate, Investor-owned (% of installed cost)       5.83%         Transmission       5.83%         Generation       6.51%         Avoided capacity cost proxy (Cost of New Entry, CONE)       6.51%         Capacity cost of new combustion turbine (2022\$/kW)       \$ 900         Storage for biofuels for proxy CT (2022 \$/kW)       \$ 900         Proposed ITC on HVDC and HVAC transmission lines (% of capital cost)       0%         Sensitivity: Try 30% per proposed ITC bill (S.1016, Henrich)       3%         Denefit/Cost Analysis (SM in 2030)       900         Power from the Prainie Project Costs       \$ 397         Annual investment-related fixed costs of PftP DC line       \$ 397
Levelized annual fixed charge rate, Investor-owned (% of installed cost)       5.83%         Transmission       5.83%         Generation       6.51%         Avoided capacity cost proxy (Cost of New Entry, CONE)       6.51%         Capacity cost of new combustion turbine (2022\$/kW)       \$ 900         Storage for biofuels for proxy CT (2022 \$/kW)       \$ 900         Proposed ITC on HVDC and HVAC transmission lines (% of capital cost)       0%         Cost escalation rate (%/year)       3%         Benefit/Cost Analysis (\$M in 2030)       7         Power from the Prainte Project Costs       8         Annual investment-related fixed costs of PftP DC line       \$ 397
Transmission     5.83%       Generation     6.51%       Avoided capacity cost proxy (Cost of New Entry, CONE)     6.51%       Capacity cost of new combustion turbine (2022\$/kW)     \$ 900       Storage for biofuels for proxy CT (2022 \$/kW)     \$ 67 \$10M per 150 MW of CT capacity.       Proposed ITC on HVDC and HVAC transmission lines (% of capital cost)     0% Sensitivity: Try 30% per proposed ITC bill (S.1016, Henrich)       Cost escalation rate (%/year)     3%       Benefit/Cost Analysis (SM in 2030)     7       Power from the Prairie Project Costs     7       Annual investment-related fixed costs of PftP DC line     \$ 397
Generation     6.51%       Avoided capacity cost proxy (Cost of New Entry, CONE)     6.51%       Capacity cost of new combustion turbine (2022\$/kW)     \$ 900       Storage for biofuels for proxy CT (2022 \$/kW)     \$ 67       Storage for biofuels for proxy CT (2022 \$/kW)     \$ 67       Proposed ITC on HVDC and HVAC transmission lines (% of capital cost)     0%       Sensitivity: Try 30% per proposed ITC bill (S.1016, Henrich)       Cost escalation rate (%/year)     3%
Avoided capacity cost proxy (Cost of New Entry, CONE)       Capacity cost of new combustion turbine (2022\$/kW)       \$ 900         Capacity cost of new combustion turbine (2022\$/kW)       \$ 900       \$ 67         Storage for biofuels for proxy CT (2022 \$/kW)       \$ 67       \$10M per 150 MW of CT capacity.         Proposed ITC on HVDC and HVAC transmission lines (% of capital cost)       0% Sensitivity: Try 30% per proposed ITC bill (S.1016, Henrich)         Cost escalation rate (%/year)       3%         Benefit/Cost Analysis (\$M in 2030)       Power from the Prairie Project Costs         Power from the Prairie Project Costs       \$ 397         True viewment-related fixed costs of PftP DC line       \$ 397
Capacity cost of new combustion turbine (2022\$/kW)       \$ 900         Storage for biofuels for proxy CT (2022 \$/kW)       \$ 67         Proposed ITC on HVDC and HVAC transmission lines (% of capital cost)       0%         Sensitivity: Try 30% per proposed ITC bill (S.1016, Henrich)         Cost esclation rate (%/year)       3%         Benefit/Cost Analysis (\$M in 2030)       9         Power from the Prairie Project Costs       9         Annual investment-related fixed costs of PftP DC line       \$ 397         Find to the project bird fixed costs of PftP DC line       \$ 20
Storage for biofuels for proxy CT (2022 \$/kW)       \$ 67 \$10M per 150 MW of CT capacity.         Proposed ITC on HVDC and HVAC transmission lines (% of capital cost)       0% Sensitivity: Try 30% per proposed ITC bill (S.1016, Henrich)         Cost escalation rate (%/year)       3%         Benefit/Cost Analysis (SM in 2030)
Proposed ITC on HVDC and HVAC transmission lines (% of capital cost) Cost escalation rate (%/year) Benefit/Cost Analysis (5M in 2030) Power from the Prairie Project Costs Annual investment-related fixed costs of PftP DC line \$ 397 The University of the Prairie Project Costs The University of the Prairie Prair
Cost escalation rate (%/year) 3% Benefit/Cost Analysis (\$M in 2030) Power from the Prairie Project Costs Annual investment-related fixed costs of PftP DC line \$ 397 Find the Province of the
Benefit/Cost Analysis (\$M in 2030)       Power from the Prainie Project Costs       Annual investment-related fixed costs of PftP DC line       \$ 397
Power from the Prairie Project Costs Annual investment-related fixed costs of PftP DC line 5 5 6 7 7 7 7 7 7 7 7 7 7 7 7 7 7 7 7 7
Annual investment-related fixed costs of PftP DC line \$ 397
Hixed Using on PTCP HDUC line \$ 3.3
Total Annual fixed costs, PftP DC and AC transmission lines \$ 522
Annual investment-related fixed costs on PftP generic renewables* \$ 203
Annual investment-related cost on AC interconnection Tx for PftP-enabled renewables \$ 35
Total Annual fixed costs, PftP generic renewables \$ 238
Total Fixed Costs of PftP line and its renewables     \$     76
Power from the Prairie Project Benefits
Capacity value of new renewables enabled by PftP at ELCC \$ (57)
Change in Regional APC compared to Scenario A attributable to PftP and renewables \$ (816)
Net Cost (Benefit) of PftP and its generic renewables \$ (87
Net Benefit/Cost Ratio
Net Benefit/Cost Batio if proposed 30% ITC on transmission*
The obligation of the original



## Exhibit V-7L. Scenario B, Public Power, RTO Perspective **Without** hypothetical capital structure

Scenario B: Add PftP line to Scenario A (with Soo Green at 2100 MW), Public Power Finan	cials, RTO Perspecti	ive, No Hypo	othetical Capital Structure
Assumptions (All numbers in 2030S unless noted)			
PftP HVDC Line capital cost (SM)			
Capacity (MW)	4.000	CDS Study	Team estimate
Capital cost (\$M)	\$ 6.814	CDS Study	Team estimate
Capital cost converters only (\$M)	\$ 3,167	CDS Study	Team estimate
Capital cost, DC lines only (\$M)	\$ 3,647	CDS Study	Team estimate
Eixed O&M (\$/converter_2022\$)	\$ 650,000	30% Jahor	loading
PftP AC Interconnection lines added for Scenario B	¢ 030,000	5070 10001	
Capital cost (SM)	\$ 2.085	CDS Study	Team estimate (2030\$)
Generic new renewables added with PftP	ç 2,000	cossiday	
Installed capacity (MW)	3.000	CDS Study	Teamestimate
Renewables mix solar/wind (energy basis)	30%/70%	cooocaay	
Renewables mix, solar/wind (chergy basis)	1 75/2 00		
Capital cost (\$/kW)	\$		
AC interconnection transmission capital cost (\$/kW)	¢ _		
Weighted average ELCC canacity value of renewables (% of total installed canacity)	- - -	Current El	CC of 15% and 50% reduced to 10% and 40% 1 75.2
Inflation Reduction Act Invoctment Tay credit (% of capital cost)	0.24		iscount on ITC due to tax exampt financing EOV
Initiation Reduction Act investment tax credit (% of capital cost)	51/0	5 IIVA, 1376 U	iscount on the due to tax-exampt mancing, 50%
Transmission	E 030/		
Concertion	5.05%	, ,	
Avoided capacity cost provy (Cost of New Entry, CONE)	0.51%	2	
Avoided capacity cost proxy (Cost of New Entry, CONE)	ć 000		
Capacity cost of new combustion turbine (20225/kw)	\$ 900	ć4014	
Storage for blotueis for proxy CI (2022 \$/kW)	\$ 67	S10ivi per 1	LSU MW OF CT capacity.
Proposed ITC on HVDC and HVAC transmission lines (% of capital cost)	0%	Sensitivity	: Try 30% per proposed ITC bill (S.1016, Henrich)
Cost escalation rate (%/year)	3%	6	
Benefit/Cost Analysis (\$M in 2030)			
Power from the Prairie Project Costs			
Annual investment-related fixed costs of PftP DC line	\$ 397		
Fixed O&M on PftP HVDC line	\$ 3.3		
Annual investment-related fixed costs on PftP AC interconnection lines	\$ 122		
Total Annual fixed costs, PftP DC and AC transmission lines		\$ 522	
Annual investment-related fixed costs on PftP generic renewables*	\$ -		
Annual investment-related cost on AC interconnection Tx for PftP-enabled renewa	15 -		
Total Annual fixed costs, PftP generic renewables	-	\$ -	
Total Fixed Costs of PftP line and its renewables			\$ 522
Power from the Prairie Project Benefits			
Capacity value of new renewables enabled by PftP at ELCC		\$ (57)	
Change in Regional APC compared to Scenario A attributable to PftP and renewable	25	\$ (816)	
Net Cost (Benefit) of PftP and its generic renewables			\$ (873)
Net Benefit/Cost Ratio			1.67
Net Benefit/Cost Ratio if proposed 30% ITC on transmission*			2.38

\*If public power made eligible for credit like done in the IRA for renweables and storage



# Exhibit V-7L. Scenario B, Public Power, RTO Perspective (continued) <u>*With*</u> hypothetical capital structure

Scenario B: Add PftP line to Scenario A (with Soo Green at 2100 MW), Public Power Financic	als, RTO Perspecti	ve, Hypothe	etical Capital Structure
Assumptions (All numbers in 2020\$ unless noted)			
PftP HVDC Line canital cost (\$M)			
Canacity (MW)	4 000	CDS Study	Team estimate
Capital cost (SM)	\$ 6.814	CDS Study	Team estimate
Capital cost converters only (\$M)	\$ 3,167	CDS Study	Team estimate
Capital cost, converces only (\$M)	\$ 3,647	CDS Study	Team estimate
Eixed O&M (\$/converter_2022\$)	\$ 650,000	30% Jahor	loading
PftP AC Interconnection lines added for Scenario B	¢ 050,000	5070 10001	10001115
Capital cost (\$M)	\$ 2.085	CDS Study	Team estimate (2030\$)
Generic new renewables added with PftP	7 _,	,	(
Installed capacity (MW)	3.000	CDS Study	Team estimate
Renewables mix, solar/wind (energy basis)	30%/70%		
Renewables mix, solar/wind (capacity basis)	1.75/2.00		
Capital cost (\$/kW)	Ś -		
AC interconnection transmission capital cost (\$/kW)	\$ -		
Weighted average ELCC capacity value of renewables (% of total installed capacity)	0.24	Current EL	
Inflation Reduction Act Investment Tax credit (% of capital cost)	31%	IRA, 15% c	liscount on ITC due to tax-exampt financing, 50%
Levelized annual fixed charge rate, Investor-owned (% of installed cost)			
Transmission	12.00%		
Generation	6.51%		
Avoided capacity cost proxy (Cost of New Entry, CONE)			
Capacity cost of new combustion turbine (2022\$/kW)	\$ 900		
Storage for biofuels for proxy CT (2022 \$/kW)	\$ 67	\$10M per	150 MW of CT capacity.
Proposed ITC on HVDC and HVAC transmission lines (% of capital cost)	0%	Sensitivity	: Try 30% per proposed ITC bill (S.1016, Henrich)
Cost escalation rate (%/year)	3%		
Benefit/Cost Analysis (\$M in 2030)			
Power from the Prairie Project Costs			
Annual investment-related fixed costs of PftP DC line	\$ 818		
Fixed O&M on PftP HVDC line	\$ 3.3		
Annual investment-related fixed costs on PftP AC interconnection lines	\$ 250		
Total Annual fixed costs, PftP DC and AC transmission lines		\$ 1,071	
Annual investment-related fixed costs on PftP generic renewables*	\$ -		
Annual investment-related cost on AC interconnection Tx for PftP-enabled renewable	\$-		
Total Annual fixed costs, PftP generic renewables		\$ -	
Total Fixed Costs of PftP line and its renewables			\$ 1,071
Power from the Prairie Proiect Benefits			
Capacity value of new renewables enabled by PftP at ELCC		Ś (57)	
Change in Regional APC compared to Scenario A attributable to PftP and renewables		\$ (816)	
Net Cost (Benefit) of PftP and its generic renewables			\$ (873)
Net Benefit/Cost Ratio			0.82
Net Benefit/Cost Ratio if proposed 30% ITC on transmission*			1.16





Exhibit V-7M. Scenario C: GCPSP, Investor-Owned

This information is Confidential to the GCPSP project owners who are CDS Participants. It is provided in Volume 3 of this Report.

Exhibit V-7N. Scenario C: GCPSP, Public Power

This information is Confidential to the GCPSP project owners who are CDS Participants. It is provided in Volume 3 of this Report.



### Exhibit V-70. Scenario D: MP Connection, Investor, Total Resource Perspective

Scenario D: Add MP Connection to PftP. Investor Financina, Total Resource Perspective						
otente si nu un cometton to ju jinestor i manangj rotantesource i espectate						
Assumptions						
MP ND to Duluth HVDC Line capital cost (\$M)						
Capacity (MW)	3	3.000 N	IP assump	tion		
Total Capital cost (SM)	\$ 2	2.074 C	DS Study T	eam estimate (2022\$)		
Capital cost, converters only (SM)	\$ 1	1.080 C	DS Study T	eam estimate (2022\$)		
Capital cost, DC overhead lines only (SM)	Ś	994 C	DS Study T	eam estimate (2022\$)		
Fixed O&M (\$/converter, 2022\$)	\$ 650	0,000 3	, )% labor lo	bading		
Generic new renewables added with Ungraded HVDC line						
Incremental installed capacity (MW)	2	2 500 M	IP assumn	tion		
Renewables mix_solar/wind (energy basis)	30%/	/70%	i ussump			
Renewables mix, solar/wind (canacity basis)	1 75/	/2 00				
Capital cost (\$/kW)	\$ 1	1 500				
AC interconnection transmission canital cost (\$/kW)	\$ 1	200				
	Ş	200				
Weighted average ELCC capacity value of renewables (% of total installed capacity)	0.24		Current ELCC of 15% and 50% reduced to 10 solar:wind capacity mix.		to 10% and 40%, 1.75:2	
Inflation Reduction Act Investment Tax credit (% of capital cost)		30% Ir	flation Re	duction Act		
MP Connection AC Interconnection lines added for Scenario D						
Capital cost (2022\$M)	\$	525 C	DS Study T	eam estimate		
Levelized annual fixed charge rate, Investor-owned (% of installed cost)						
Transmission	12	2.00%				
Generation	9	9.40%				
Avoided capacity cost proxy (Cost of New Entry, CONE)						
Capacity cost of new combustion turbine (2022\$/kW)	\$	900				
Storage for biofuels for proxy CT (2022 \$/kW)	\$	67 \$	\$10M per 150 MW of CT capacity.			
Proposed ITC on HVDC and HVAC transmission lines (% of capital cost)		0% S	ensitivity:	Try 30% per Heinrich bill.		
Cost escalation rate (%/year)		3%				
Benefit/Cost Analysis (SM in 2030)						
MP Connection Project Costs						
Annual investment-related Fixed costs on MP HVDC Line	Ş	315				
Fixed O&M, MP HVDC line	Ş	2				
Annual investment-related Fixed costs on AC interconnection Lines	Ş	49				
Total Annual fixed costs, TWE line			366			
Annual investment-related fixed costs on MP Connection enabled renewables	\$	247				
Annual investment-related cost on AC interconnection Tx for MP enabled renewables	\$	76				
Total Annual fixed costs, MP enabled renewables		:	323			
Total Fixed Costs of MP Connection and its renewables				\$ 689		
MP Connection Project Benefits						
Capacity value of new renewables enabled by MP Connection at ELCC		9	(69)			
Change in Regional APC compared to Scenario B attributable to MP and its renewables		\$	(314)			
Net Cost (Benefit) of MP Connection and its enabled renewables				\$ (383)		
Net Benefit/Cost Ratio				0.56		
Net Benefit/Cost Ratio with proposed 30% ITC on transmission				0.76		



## Exhibit V-7P. Scenario D: MP Connection, Investor, RTO Perspective

Scenario D: Add MP Connection to PftP, Investor Financing, RTO Perspective				
Accumptions				
MP ND to Duluth HVDC Line capital cost (\$M)				
Capacity (MW)	3,000	MP assum	ption	
Total Capital cost (\$M)	\$ 2,074	CDS Study	Team estir	nate (2022\$)
Capital cost, converters only (\$M)	\$ 1,080	CDS Study	Team estir	nate (2022\$)
Capital cost, DC overhead lines only (\$M)	\$ 994	CDS Study	Team estir	nate (2022\$)
Fixed O&M (\$/converter, 2022\$)	\$ 650,000	30% labor	loading	
Generic new renewables added with Upgraded HVDC line				
Incremental installed capacity (MW)	2,500	MP assum	ption	
Renewables mix, solar/wind (energy basis)	30%/70%			
Renewables mix, solar/wind (capacity basis)	1.75/2.00			
Capital cost (\$/kW)	\$-			
AC interconnection transmission capital cost (\$/kW)	\$-			
Weighted average ELCC capacity value of renewables (% of total installed capacity)	0.24	Current El	.CC of 15% a	and 50% reduced to
Inflation Reduction Act Investment Tax credit (% of capital cost)	30%	Inflation F	Reduction A	ct
MP Connection AC Interconnection lines added for Scenario D				
Capital cost (2022\$M)	\$ 525	CDS Study	Team estir	nate
Levelized annual fixed charge rate, Investor-owned (% of installed cost)				
Transmission	12.00%			
Generation	9.40%			
Avoided capacity cost proxy (Cost of New Entry, CONE)				
Capacity cost of new combustion turbine (2022\$/kW)	\$ 900			
Storage for biofuels for proxy CT (2022 \$/kW)	\$ 67	\$10M per	150 MW of	CT capacity.
Proposed ITC on HVDC and HVAC transmission lines (% of capital cost)	0%	Sensitivit	y: Try 30% p	er Heinrich bill.
Cost escalation rate (%/year)	3%			
Benefit/Cost Analysis (\$M in 2030)				
MP Connection Project Costs				
Annual investment-related Fixed costs on MP HVDC Line	\$ 315			
Fixed O&M, MP HVDC line	\$ 2			
Annual investment-related Fixed costs on AC interconnection Lines	\$ 49			
Total Annual fixed costs, TWE line		\$ 366		
Annual investment-related fixed costs on MP Connection enabled renewables	\$-			
Annual investment-related cost on AC interconnection Tx for MP enabled renewables	\$-			
Total Annual fixed costs, MP enabled renewables		\$ -		
Total Fixed Costs of MP Connection and its renewables			\$ 366	
MP Connection Project Benefits				
Capacity value of new renewables enabled by MP Connection at ELCC		\$ (69)		
Change in Regional APC compared to Scenario B attributable to MP and its renewables		\$ (314)		
Net Cost (Benefit) of MP Connection and its enabled renewables			\$ (383)	
Net Benefit/Cost Ratio			1.05	
Net Benefit/Cost Ratio with proposed 30% ITC on transmission			1.49	



#### Exhibit V-7Q. Scenario D: MP Connection, Public Power, Total Resource Perspective

Scenario D: Add MP Connection to PftP, Public financing, Total Resource Perspective				
Assumptions				
MP ND to Duluth HVDC Line capital cost (\$M)				
Capacity (MW)	3,000	MP assumpti	on	
Total Capital cost (\$M)	\$ 2,074	CDS Study Te	am estimate (2022\$)	
Capital cost, converters only (\$M)	\$ 1,080	CDS Study Te	am estimate (2022\$)	
Capital cost, DC overhead lines only (\$M)	\$ 994	CDS Study Te	am estimate (2022\$)	
Fixed O&M (\$/converter, 2022\$)	\$ 650,000	30% labor loa	ading	
Generic new renewables added with Upgraded HVDC line				
Incremental installed capacity (MW)	2,500	MP assumpti	on	
Renewables mix, solar/wind (energy basis)	30%/70%			
Renewables mix, solar/wind (capacity basis)	1.75/2.00			
Capital cost (\$/kW)	\$ 1,500			
AC interconnection transmission capital cost (\$/kW)	\$ 200			
Weighted average ELCC capacity value of renewables (% of total installed capacity)	0.24	Current ELCC reduced to 10 solar:wind ca	of 15% and 50% 0% and 40%, 1.75:2 pacity mix.	
Inflation Reduction Act Investment Tax credit (% of capital cost)	30%	Inflation Red	uction Act	
MP Connection AC Interconnection lines added for Scenario D				
Capital cost (2020\$M)	\$ 525	CDS Study Te	am estimate	
Levelized annual fixed charge rate, Investor-owned (% of installed cost)				
Transmission	5.83%			
Generation	6.51%			
Avoided capacity cost proxy (Cost of New Entry, CONE)				
Capacity cost of new combustion turbine (2022\$/kW)	\$ 900			
Storage for biofuels for proxy CT (2022 \$/kW)	\$ 67	\$10M per 150	MW of CT capacity.	
Proposed ITC on HVDC and HVAC transmission lines (% of capital cost)	0%	Sensitivity: T	ry 30% per Heinrich b	ill.
Cost escalation rate (%/year)	 3%			
Benefit/Cost Analysis (\$M in 2030)				
Transwest Express Project Costs				
Annual investment-related Fixed costs on MP HVDC Line	\$ 121			
Fixed O&M, MP HVDC line	\$ 2			
Annual investment-related Fixed costs on AC interconnection Lines	\$ 39			
Total Annual fixed costs, TWE line		\$ 161		
Annual investment-related fixed costs on MP Connection enabled renewables	\$ 171			
Annual investment-related cost on AC interconnection Tx for MP enabled renewables	\$ 29			
Total Annual fixed costs, MP enabled renewables		\$ 200		
Total Fixed Costs of MP Connection and its renewables			\$ 361	
Transwest Express Project Benefits				
Capacity value of new renewables enabled by MP Connection at ELCC		\$ (48)		
Change in Regional APC compared to Base Case attributable to TWE and its renewables		\$ (314)		
Net Cost (Benefit) of MP Connection and its enabled renewables			\$ (362)	
Net Benefit/Cost Ratio			1.00	
Net Benefit/Cost Ratio if 30% ITC on transmission per Heinrich bill.*			1.15	
*Assumes public power is eligible for credit benefit as IRA offers renewables and storage.				



#### Exhibit V-7R. Scenario D: MP Connection, Public Power, RTO Perspective Without hypothetical capital structure

Scenario D: Add MP Connection to PftP, Public financing, RTO Perspective, No Hypothetica	l Tx Capital Struc	<u>ture</u>		
Accumptions				
MP ND to Duluth HVDC Line canital cost (\$M)				
Canacity (MW)	3 000	MP assum	ntion	
Total Capital cost (\$M)	\$ 2,074	CDS Study	/ Team esti	mate (2022\$)
Capital cost converters only (\$M)	\$ 1.080	CDS Study	/ Team esti	mate (2022\$)
Capital cost, Converters only (SM)	\$ 994	CDS Study	/ Team esti	mate (2022\$)
Fixed O&M (\$/converter_2022\$)	\$ 650,000	30% Jahor	loading	nute (2022¢)
Seneric new renewables added with Ungraded HVDC line	\$ 050,000	50/0 10501	louunig	
Incremental installed canacity (MW)	2 500	MP assum	ntion	
Renewables mix_solar/wind (energy basis)	30%/70%	ivii ussuii	iption .	
Renewables mix, solar/wind (canacity basis)	1 75/2 00			
Canital cost (\$/kW)	¢ _			
AC interconnection transmission canital cost (\$/kW)	\$ -			
Weighted average ELCC capacity value of renewables (% of total installed capacity)	0.24	Current F	CC of 15%	
Inflation Reduction Act Investment Tax credit (% of capital cost)	30%	Inflation	Reduction A	rt
MP Connection AC Interconnection lines added for Scenario D				
Capital cost (2020SM)	\$ 525	CDS Study	/ Team esti	mate
evelized annual fixed charge rate. Investor-owned (% of installed cost)	Ş 525	CD5 Study	, ream esti	nate
Transmission	5 83%			
Generation	6 51%			
Avoided canacity cost proxy (Cost of New Entry, CONE)	0.01/0			
Canacity cost of new combustion turbine (2022\$/kW)	\$ 900			
Storage for biofuels for proxy CT (2022 \$/kW)	\$ 67	\$10M ner	150 MW of	CT canacity
Pronosed ITC on HVDC and HVAC transmission lines (% of canital cost)	÷ 0%	Sensitivity: Toy 20% per Heiprich bil		
Cost escalation rate (%/war)	3%	Sensitivity. Hy 50% per hermitin bin		
	376			
Benefit/Cost Analysis (\$M in 2030)				
Transwest Express Project Costs				
Annual investment-related Fixed costs on MP HVDC Line	\$ 121			
Fixed O&M, MP HVDC line	\$ 2			
Annual investment-related Fixed costs on AC interconnection Lines	\$ 39			
Total Annual fixed costs, TWE line		\$ 161		
Annual investment-related fixed costs on MP Connection enabled renewables	Ş -			
Annual investment-related cost on AC interconnection Tx for MP enabled renewable	ş -		-	
Total Annual fixed costs, MP enabled renewables		Ş -		
Total Fixed Costs of MP Connection and its renewables			\$ 161	
Transwest Express Project Benefits				
Canacity value of new renewables enabled by MP Connection at FLCC		\$ (48)		
Change in Regional APC compared to Base Case attributable to TWF and its renewable	PS	\$ (314)		
Net Cost (Benefit) of MP Connection and its enabled renewables		(514) ر	\$ (362)	
Net Percefit (Cost Patie			2 2 2 4	
Net Benefit/Lost Katio			2.24	
Net Benefit/Cost Ratio if 30% ITC on transmission per Heinrich bil	.*		3.19	



#### Exhibit V-7R. Scenario D: MP Connection, Public Power, RTO Perspective (continued) With hypothetical capital structure

Scenario D: Add MP Connection to PftP, Public financing, RTO Perspective, Hypothetical Tx Co	apital Structure			
Assumptions				
MP ND to Duluth HVDC Line capital cost (\$M)				
Capacity (MW)	3.000	MP assum	notion	
Total Capital cost (\$M)	\$ 2,074	CDS Study	/ Team estin	mate (2022\$)
Capital cost, converters only (\$M)	\$ 1,080	CDS Study	v Team estii	mate (2022\$)
Capital cost, DC overhead lines only (\$M)	\$ 994	CDS Study	, y Team estii	mate (2022\$)
Fixed O&M (\$/converter, 2022\$)	\$ 650,000	30% labor	loading	
Generic new renewables added with Upgraded HVDC line				
Incremental installed capacity (MW)	2,500	MP assum	nption	
Renewables mix, solar/wind (energy basis)	30%/70%			
Renewables mix, solar/wind (capacity basis)	1.75/2.00			
Capital cost (\$/kW)	\$ -			
AC interconnection transmission capital cost (\$/kW)	\$ -			
Weighted average ELCC capacity value of renewables (% of total installed capacity)	0.24	Current El	LCC of 15%	
Inflation Reduction Act Investment Tax credit (% of capital cost)	30%	Inflation I	Reduction A	vct
MP Connection AC Interconnection lines added for Scenario D				
Capital cost (2020\$M)	\$ 525	CDS Study	y Team estin	mate
Levelized annual fixed charge rate, Investor-owned (% of installed cost)				
Transmission	12.00%			
Generation	6.51%			
Avoided capacity cost proxy (Cost of New Entry, CONE)				
Capacity cost of new combustion turbine (2022\$/kW)	\$ 900			
Storage for biofuels for proxy CT (2022 \$/kW)	\$ 67	\$10M per	150 MW of	CT capacity.
Proposed ITC on HVDC and HVAC transmission lines (% of capital cost)	0%	Sensitivity: Try 30% per Heinrich bill.		
Cost escalation rate (%/year)	3%		ļļ	
Benefit/Cost Analysis (\$M in 2030)				
Transwest Express Project Costs				
Annual investment-related Fixed costs on MP HVDC Line	\$ 249			
Fixed O&M, MP HVDC line	\$ 2			
Annual investment-related Fixed costs on AC interconnection Lines	\$ 80			
Total Annual fixed costs, TWE line		\$ 330		
Annual investment-related fixed costs on MP Connection enabled renewables	\$-			
Annual investment-related cost on AC interconnection Tx for MP enabled renewables	\$ -			
Total Annual fixed costs, MP enabled renewables		\$ -		
Total Fixed Costs of MP Connection and its renewables			\$ 330	
Transwest Express Project Benefits				
Capacity value of new renewables enabled by MP Connection at ELCC		\$ (48)		
Change in Regional APC compared to Base Case attributable to TWE and its renewables		\$ (314)		
Net Cost (Benefit) of MP Connection and its enabled renewables			\$ (362)	
Net Benefit/Cost Ratio			1.10	
Net Benefit/Cost Ratio if 30% ITC on transmission per Heinrich bill.*			1.56	

\*Assumes public power is eligible for credit benefit as IRA offers renewables and storage.



## Exhibit V-7S. Scenario E: Utah CAES, Investor-Owned, Total Resource Perspective

Scenario E: Add Utah CAES to Scenario B, IOU financials, Total Resource Perspective					
Assumptions (All numbers in 2030\$ unless noted)					
Utah CAES capital cost (ŚM)					
Capacity (MW)	1	.200			
Capital cost (\$/kW in 2022\$, for 48 hours duration)	\$ 2	,030	SCPPA RFP for	CAES projects.	
GCPSP Fixed O&M cost (S/kW-vear in 2022S)	Ś	62	SCPPA RFP for	CAES projects.	
PftP AC Interconnection lines needed for GCPSP					
Capital cost (\$M)	\$	-	Minimal tx nee	ded.	
Generic new renewables added with GCPSP					
Installed capacity (MW)	1	,200	CDS Study Tear	m estimate	
Renewables mix, solar/wind (energy basis)	30%/	70%			
Renewables mix, solar/wind (capacity basis)	1.75/	2.00			
Capital cost (\$/kW)	\$ 1	,500			
AC interconnection transmission capital cost (\$/kW)	\$	200			
Weighted average ELCC capacity value of renewables (% of total installed capacity)		0.24	Current ELCC o	f 15% and 50% re	duced to 10% and 40%, 1.75:2
Inflation Reduction Act Investment Tax credit (% of capital cost)		30%	IRA		
Levelized annual fixed charge rate, Investor-owned (% of installed cost)					
Transmission	12	2.00%			
Generation	g	9.40%			
Avoided capacity cost proxy (Cost of New Entry, CONE)					
Capacity cost of new combustion turbine (2022\$/kW)	\$	900			
Storage for biofuels for proxy CT (2022 \$/kW)	\$	67	\$10M per 150 N	/W of CT capacity	
IRA ITC on pumped hydro storage (% of capital cost)		0%	Sensitivity: Do	es CAES qualify f	or IRA 30% ITC on storage?
Cost escalation rate (%/year)		3%			
Parafit/Cast Analysis (ChAin 2020)					
Greanry County Pumped Storage Project (GCPSP) Costs, with PftP in place					
Annual investment-related fixed costs of Litab CAFS	Ś	290			
GCPSP Fixed O&M	Ś	94			
Annual investment-related fixed costs on Utah CAES AC interconnection lines	Ś	-		No tx necessary	
Total Annual fixed costs. Utah CAES and AC transmission lines	-		Ś 384	,,	
Annual investment-related fixed costs on Utah CAES generic renewables	\$	118			
Annual investment-related cost on AC interconnection Tx for CAES enabled renewables	\$	29			
Total Annual fixed costs, PftP generic renewables			\$ 118		
Total Fixed Costs of PftP line and its renewables				\$ 502	
Utah CAES Benefits, with PftP in place					
Capacity value of new renewables enabled by Utah CAES at ELCC			\$ (26)		
Avoided cost of non-renewable generation necessary to replace retirements (net of renewables value)			\$ (83)		
Change in Regional APC compared to Scenario B attributable to Utah CAES			\$ (177)		
Net Incremental Cost (Benefit) of Utah CAES compared to Scenario B				\$ (286)	
Net Benefit/Cost Ratio				0.57	
Net Benefit/Cost Ratio if Utah CAES eligible for 30% ITC for storage in the IRA				0.69	



## Exhibit V-7T. Scenario E: Utah CAES, Investor-Owned, RTO Perspective

Scenario E: Add Utah CAES to Scenario B, IOU financials, <u>RTO Perspective</u>					
Assumptions (All numbers in 2030\$ unless noted)					
Utah CAES capital cost (\$M)					
Capacity (MW)		1,200			
Capital cost (\$/kW in 2022\$, for 48 hours duration)	Ş	2,030	SCPPA R	P for C	AES projects.
GCPSP Fixed O&M cost (\$/kW-year in 2022\$)	\$	62	SCPPA R	FP for C/	AES projects.
PftP AC Interconnection lines needed for GCPSP					
Capital cost (\$M)	\$	-	Minimal	tx need	ed.
Generic new renewables added with GCPSP					
Installed capacity (MW)		1,200	CDS Stud	y Team	estimate
Renewables mix, solar/wind (energy basis)		30%/70%			
Renewables mix, solar/wind (capacity basis)		1.75/2.00			
Capital cost (\$/kW)	\$	-			
AC interconnection transmission capital cost (\$/kW)	Ş	-			
Weighted average ELCC capacity value of renewables (% of total installed capacity)		0.24	Current	LCC of :	L5% and 50% reduced to 10% and 40%,
Inflation Reduction Act Investment Tax credit (% of capital cost)		30%	IRA		
Levelized annual fixed charge rate, Investor-owned (% of installed cost)					
Transmission		12.00%			
Generation		9.40%			
Avoided capacity cost proxy (Cost of New Entry, CONE)					
Capacity cost of new combustion turbine (2022\$/kW)	\$	900			
Storage for biofuels for proxy CT (2022 \$/kW)	\$	67	\$10M pe	r 150 M\	V of CT capacity.
IRA ITC on pumped hydro storage (% of capital cost)		0%	Sensitivi	ty: Does	CAES qualify for IRA 30% ITC on storage?
Cost escalation rate (%/year)		3%			
<u>Benefit/Cost Analysis (\$M in 2030)</u>					
Gregory County Pumped Storage Project (GCPSP) Costs, with PftP in place					
Annual investment-related fixed costs of Utah CAES	\$	290			
GCPSP Fixed O&M	\$	94			
Annual investment-related fixed costs on Utah CAES AC interconnection lines	Ş	-		No tx	necessary.
Total Annual fixed costs, Utah CAES and AC transmission lines			\$ 384		
Annual investment-related fixed costs on Utah CAES generic renewables	\$	-			
Annual investment-related cost on AC interconnection Tx for CAES enabled renewables	Ş	-		_	
Total Annual fixed costs, PftP generic renewables			Ş -		
Total Fixed Costs of PHtP line and its renewables				Ş 3	84
Utah CAES Benefits, with PftP in place					
Capacity value of new renewables enabled by Utah CAES at ELCC			\$ (26	;)	
Avoided cost of non-renewable generation necessary to replace retirements (net of renewables value)			\$ (83	)	
Change in Regional APC compared to Scenario B attributable to Utah CAES			¢ (177	n	
			2 (I//	/	
Net Incremental Cost (Benefit) of Utah CAES compared to Scenario B			\$ (177	\$ (2	(86)
Net Incremental Cost (Benefit) of Utah CAES compared to Scenario B Net Benefit/Cost Ratio			<u> </u>	\$ (2 0.7	186) 74



## Exhibit V-7U. Scenario E: Utah CAES, Public Power, Total Resource Perspective

Scenario E: Add Utah CAES to Scenario B, Public Power financing, Total Resource Perspective							
Assumptions (All numbers in 20305 unless noted)							
Utan CAES capital cost (SM)		4 200					
Capacity (INW)		1,200					
Capital cost (SM for 48 nours duration)	Ş	2,030					
Capital cost, facility w/o storage reservoir (SW)							
Capital cost, URG storage reservoir only, 48 nours (SMI)							
Utah CAES Fixed U&M cost (\$/kW-year in 2022\$)	Ş	62					
PftP AC Interconnection lines needed for Utah CAES							
Capital cost (SM)	Ş	-	Min	mal tx r	needed.		
Generic new renewables added with Utah CAES							
Installed capacity (MW)		1,200	CDS	Study T	eam esti	mate	
Renewables mix, solar/wind (energy basis)		30%/70%					
Renewables mix, solar/wind (capacity basis)		1.75/2.00					
Capital cost (\$/kW)	\$	1,500					
AC interconnection transmission capital cost (\$/kW)	\$	200					
Weighted average ELCC capacity value of renewables (% of total installed capacity)		0.24	Curr	ent ELC	C of 15%	and 50%	reduced to 10% and 40%, 1.75:2
Inflation Reduction Act Investment Tax credit (% of capital cost)		30%	IRA				
Levelized annual fixed charge rate, Investor-owned (% of installed cost)							
Transmission		5.83%					
Generation		6.51%					
Avoided capacity cost proxy (Cost of New Entry, CONE)							
Capacity cost of new combustion turbine (2022\$/kW)	\$	900					
Storage for biofuels for proxy CT (2022 \$/kW)	\$	67	\$10	И per 15	60 MW of	CT capao	city.
IRA ITC on pumped hydro storage (% of capital cost)		0%	Sen	sitivity:	Does CA	ES qualif	y for IRA 30% ITC on storage?
Cost escalation rate (%/year)		3%					
Panafit/Cart Analysis (CAA in 2020)	-						
Granny County Dummed Storgen Project (GCDCD) Costs with DftD in place							
Annual invoctment related fixed costs of Ltab CAES	ć	201					
Almudi mitestimenterelateu fixed costs of otali CAES	Ş	201					
GCPSP Fixed Date	Ş	94			Nature		
Tatel Annual Investment-related fixed costs on olan CAES AC Interconnection lines	Ş		ć	205	NO LX NO	ecessary.	
I otal Annual fixed costs, Utan CAES and AC transmission lines			\$	295			
Annual investment-related fixed costs on Utah CAES generic renewables	\$	82					
Annual investment-related cost on AC interconnection Tx for CAES enabled renewables	\$	14					
Total Annual fixed costs, PftP generic renewables			\$	82			
Total Fixed Costs of PftP line and its renewables					\$	377	
Utah CAES Benefits, with PftP in place							
Capacity value of new renewables enabled by Utah CAES at ELCC			\$	(18)			
Avoided cost of non-renewable generation necessary to replace retirements (net of renewables value)			\$	(57)			
Change in Regional APC compared to Scenario B attributable to Utah CAES			\$	(177)			
Net Incremental Cost (Benefit) of Utah CAES compared to Scenario B					\$	(252)	
Net Benefit/Cost Ratio						0.67	
Net Benefit/Cost Ratio if Utah CAES eligible for 30% ITC for storage in the IRA*						0.80	
*Assumes public power is eligible for credit benefit as IPA offers renowables and storage							



# Exhibit V-7V. Scenario E: Utah CAES, Public Power, RTO Perspective

#### Without hypothetical capital structure

Scenario E: Add Utah CAES to Scenario B, Public Power financing, <u>RTO Perspective, No Hypo</u>	thetical Tx Co	ıp St	ructure		
Assumptions (All numbers in 2030\$ unless noted)					
Utah CAES capital cost (\$M)					
Capacity (MW)	1,2	200			
Capital cost (\$M for 48 hours duration)	\$ 2,0	030			
Capital cost, facility w/o storage reservoir (\$M)					
Capital cost, URG storage reservoir only, 48 hours (\$M)					
Utah CAES Fixed O&M cost (\$/kW-year in 2022\$)	\$	62			
PftP AC Interconnection lines needed for Utah CAES					
Capital cost (\$M)	\$	-	Minimal t	k needed.	
Generic new renewables added with Utah CAES					
Installed capacity (MW)	1,3	200	CDS Study	Team esti	mate
Renewables mix, solar/wind (energy basis)	30%/7	0%			
Renewables mix, solar/wind (capacity basis)	1.75/2	.00			
Capital cost (\$/kW)	\$	-			
AC interconnection transmission capital cost (\$/kW)	\$	-			
Weighted average ELCC capacity value of renewables (% of total installed capacity)	0	.24	Current EL	CC of 15%	and 50% reduced to 10% and 40%,
Inflation Reduction Act Investment Tax credit (% of capital cost)		30%	IRA		
Levelized annual fixed charge rate, Investor-owned (% of installed cost)					
Transmission	5.	83%			
Generation	6.	51%			
Avoided capacity cost proxy (Cost of New Entry, CONE)					
Capacity cost of new combustion turbine (2022\$/kW)	\$ 9	900			
Storage for biofuels for proxy CT (2022 \$/kW)	\$	67	\$10M per	150 MW of	CT capacity.
RA ITC on pumped hydro storage (% of capital cost)		0%	Sensitivity	: Does CA	ES qualify for IRA 30% ITC on storage?
Cost escalation rate (%/year)		3%			
Benefit/Cost Analysis (\$M in 2030)					
Gregory County Pumped Storage Project (GCPSP) Costs, with PftP in place					
Annual investment-related fixed costs of Utah CAES	\$ :	201			
GCPSP Fixed O&M	Ş	94			
Annual investment-related fixed costs on Utah CAES AC interconnection lines	\$	-		No tx neo	essary.
Total Annual fixed costs, Utah CAES and AC transmission lines			Ş 295		
And the second second of the design of the bears of the second second second second second second second second	*				
Annual investment-related fixed costs on Utah CAES generic renewables	\$	-			
Annual Investment-related cost on AC Interconnection Ix for CAES enabled renewable	\$	-	ć		
Iotal Annual fixed costs, PftP generic renewables			Ş -		
Total Fixed Costs of PftP line and its renewables		-		\$ 20E	
				÷ 255	
Utah CAES Benefits, with PftP in place					
Capacity value of new renewables enabled by Utah CAES at ELCC			\$ (18)		
Avoided cost of non-renewable generation necessary to replace retirements (net of re	newables va	lue)	\$ (57)		
Change in Regional APC compared to Scenario B attributable to Utah CAES			\$ (177)		
Net Incremental Cost (Benefit) of Utah CAES compared to Scenario B				\$ (252)	
Net Benefit/Cost Ratio				0.86	
Net Benefit/Cost Ratio if Utah CAES eligible for 30% ITC for storage	in the IRA	*		1.08	



## Exhibit V-7V. Scenario E: Utah CAES, Public Power, RTO Perspective (continued)

#### With hypothetical capital structure

Scenario E: Add Utah CAES to Scenario B, Public Power financing, RTO Perspective, Hypothetical Tx Cap Structu	<u>ire</u>				
Assumptions (All numbers in 2030\$ unless noted)					
Utah CAES capital cost (\$M)					
Capacity (MW)		1,200			
Capital cost (\$M for 48 hours duration)	\$	2,030			
Capital cost, facility w/o storage reservoir (\$M)					
Capital cost, URG storage reservoir only, 48 hours (\$M)					
Utah CAES Fixed O&M cost (\$/kW-year in 2022\$)	\$	62			
PftP AC Interconnection lines needed for Utah CAES					
Capital cost (\$M)	\$	-	Minimal t	x needed.	
Generic new renewables added with Utah CAES					
Installed capacity (MW)		1,200	CDS Study	/ Team est	imate
Renewables mix, solar/wind (energy basis)	3	0%/70%			
Renewables mix, solar/wind (capacity basis)	1	.75/2.00			
Capital cost (\$/kW)	\$	-			
AC interconnection transmission capital cost (\$/kW)	\$	-			
Weighted average ELCC capacity value of renewables (% of total installed capacity)		0.24	Current El	LCC of 15%	and 50% reduced to 10% and 40%,
Inflation Reduction Act Investment Tax credit (% of capital cost)		30%	IRA		
Levelized annual fixed charge rate, Investor-owned (% of installed cost)					
Transmission		12.00%			
Generation		6.51%			
Avoided capacity cost proxy (Cost of New Entry, CONE)					
Capacity cost of new combustion turbine (2022\$/kW)	\$	900			
Storage for biofuels for proxy CT (2022 \$/kW)	\$	67	\$10M per	150 MW of	f CT capacity.
IRA ITC on pumped hydro storage (% of capital cost)		0%	Sensitivit	y: Does CA	ES qualify for IRA 30% ITC on storage?
Cost escalation rate (%/year)		3%			
Repart/Cast Anglusis (\$M in 2020)					
Gragon County Rumped Storage Project (GCRSR) Costs, with RftR in place					
Annual investment-related fixed costs of litab CAFS	¢	201			
GCPSP Fixed O&M	¢	9/			
Annual investment-related fixed costs on Litab CAES AC interconnection lines	¢	-		No ty nec	06220
Total Annual fixed costs Litab CAES and AC transmission lines	Ŷ		\$ 295	NO LA NEC	cistiy.
			Ş 255		
Annual investment-related fixed costs on Utah CAES generic renewables	Ś	-			
Annual investment-related cost on AC interconnection Tx for CAES enabled renewables	Ś	-			
Total Annual fixed costs. PftP generic renewables			Ś -		
Total Fixed Costs of PftP line and its renewables				\$ 295	
Utah CAES Benefits, with PftP in place					
Capacity value of new renewables enabled by Utah CAES at ELCC			\$ (18)		
Avoided cost of non-renewable generation necessary to replace retirements (net of renewables value)			\$ (57)		
Change in Regional APC compared to Scenario B attributable to Utah CAES			\$ (177)		
Net Incremental Cost (Benefit) of Utah CAES compared to Scenario B				\$ (252)	
Net Benefit/Cost Ratio					
				0.86	
Net Benefit/Cost Ratio if Utah CAES eligible for 30% ITC for storage in the IRA*				0.86 1.08	

Assumes public power is eligible for credit benefit as IRA offers renewables and storage



## Exhibit V-7W. Scenario E+: Utah H2, Investor-Owned

Scenario E+: Add 210 Hydrogen Electrolyzer at Delta, Utah, Investor Financing	1		
Assumptions			
Utah H2 Electrolyzer at Delta, Utah			
Capacity (MW)	210	1	
Electrolyzer capacity factor (%)	77.3	6 Load pattern input to Gridviev	w modeling.
Total Capital Cost Electrolyzer	\$ 193,200,000	Based on Lazard Study High Er	nd Capex Large Alkalline Facility
Capex of Electrolyzer Stack	\$ 91,350,000	Based on Lazard Study High Er	nd Capex Large Alkalline Facility
Life of Plant in Years	4	0	
Life of Stack in operatihg hours	75,000	Based on Lazard Study High Er	nd Capex Large Alkalline Facility
Fixed O&M (1.5% of Total Capital Cost)	\$ 2,898,000	Based on Lazard Study High Er	nd Capex Large Alkalline Facility
Variable O&M (Water) \$/kg Hydrogen	\$ 0.050	9 liters of nuclear grade demi	neralized pure water \$25/1000 gallo
Inflation Reduction Act Production Tax Credit for H2 Production (\$/kg)	\$-	16 tons carbon emissions per	ton of H2. Does not qualify.
Levelized annual fixed charge rate, Investor-owned (% of installed cost)			
Transmission	9.95	6	
Generation	9.40	6	
Annual Electrolyzer electricity input to electrolyzer (MWh)	1,422,01	210 MW @ 77.3% load factor.	
Electrolyzer efficiency (kWh in per kg of H2 out).	93	6 From HydrogenPro supplier o	f technology
H2 output per hour capacity (kg)	4,95	•	
Annual electrolyzer H2 output (kg)	33,573,75	Calculated based on higher he	eating value 39.39 kWh per kg H2
Hydrogen revenue goal (\$/kg)	\$ 4.00	•	
Utility supplier demand charge (\$/kW-month in 2022\$)	\$ 12.00	Nominal utlity average demai	nd charge per month.
Cost escalation rate (%/year)	3	6	
Benefit/Cost Analysis (SM in 2030)			
A revel 1/2 revenue at C/ka and accuraced	ć 12		
Annual H2 revenue at \$7kg goar assumed.	\$ 13	÷	
Iotal Benefits		\$ 134.30	
IItah H2 Operating Costs (SM)			
Stack depreciation as this is a consumable	\$ 8		
Fixed Q&M	\$ 20		
Variable O&M deminearlized nure	\$ 1	,	
Itility Service demand charges 210 MW (\$/year)	\$ 30		
Energy commodity cost (at LMP)	\$ 82	,	
Total Operating Cost of Litab H2	<del>Υ</del> ΟΣ.	\$ 125.76	
		5 125.70	
Net Annual Funds Available for Capital Recovery on Utah H2 (\$M)			\$ 8.53
Maximum Allowed Capital Cost of Litab H2 at assumed price goal			
Per kW of peak electric demand (210 MW)			\$ 432
Per kg H2 per hour of electrolyzer capacity			\$ 18,304



## Exhibit V-7X: Scenario E+: Utah H2, Public Power

Scenario E+: Add 210 Hydrogen Electrolyzer at Delta, Utah, Public Financing		
Assumptions		
Utah H2 Electrolyzer at Delta, Utah		
Capacity (MW)	210	
Electrolyzer capacity factor (%)	77.3%	Load pattern input to Gridview modeling.
Total Capital Cost Electrolyzer	\$193,200,000	Based on Lazard Study High End Capex Large Alkalline Facility
Capex of Electrolyzer Stack	\$ 91,350,000	Based on Lazard Study High End Capex Large Alkalline Facility
Life of Plant in Years	40	
Life of Stack in operatihg hours	75,000	Based on Lazard Study High End Capex Large Alkalline Facility
Fixed O&M (1.5% of Total Capital Cost)	\$ 2,898,000	Based on Lazard Study High End Capex Large Alkalline Facility
Variable O&M (Water) \$/kg Hydrogen	\$ 0.050	9 liters of nuclear grade demineralized pure water \$25/1000 g
Inflation Reduction Act Production Tax Credit for H2 Production (\$/kg)	\$-	16 tons carbon emissions per ton of H2. Does not qualify.
Levelized annual fixed charge rate, Investor-owned (% of installed cost)		
Transmission	5.83%	
Generation	6.51%	
Annual Electrolyzer electricity input to electrolyzer (MWh)	1,422,011	210 MW @ 77.3% load factor.
Electrolyzer efficiency (kWh in per kg of H2 out).	93%	From HydrogenPro supplier of technology
H2 output per hour capacity (kg)	4,958	
Annual electrolyzer H2 output (kg)	33,573,751	Calculated based on higher heating value 39.39 kWh per kg H2
Hydrogen revenue goal (\$/kg)	\$ 4.00	
Utility supplier demand charge (\$/kW-month in 2022\$)	\$ 12.00	Nominal utlity average demand charge per month.
Cost escalation rate (%/year)	3%	
Renefit/Cast Anglusis (CAA in 2020)		
Iltah H2 Renefits		
Annual H2 revenue at \$/kg goal assumed	\$ 134	
Total Renefits	<del>\$</del> 154	\$ 134 30
		ý 15 <del>1</del> .50
Utah H2 Operatina Costs (ŚM)		
Stack depreciation as this is a consumable	\$ 8.2	
Fixed O&M	\$ 2.9	
Variable Q&M deminearlized pure	\$ 1.7	
Utility Service demand charges, 210 MW (\$/year)	\$ 30.2	
Energy commodity cost (at LMP)	\$ 82.7	
Total Operating Cost of Utah H2		\$ 125.76
Net Annual Funds Available for Capital Recovery on Utah H2		\$ 8.53
Maximum Allowed Capital Cost of Utah H2 at assumed price goal		
Per kW of peak electric demand (210 MW)		\$ 624
Per kg H2 per hour of electrolyzer capacity		\$ 26,449



## **Power from the Prairie CDS Report** Volume 2, March 23, 2023



#### Exhibit V-7Y: Scenario E+: Utah H2, Investor and Public Power Summary





## Exhibit V-7Z. Benefit/Cost Ratios Summary, All Scenarios

Sc	enario A, Add TransWest, Benefit/Cost Ra	itios						
۸.		Total Resour	ce Perspective	<b>RTO Perspective</b>				
As	set Owner Type	Without ITC	With ITC	Without ITC	With ITC			
In	vestor-Owned Financials	0.98	1.15	2.09	2.98			
Pu	Iblic Power Financials							
	Without hypothetical capital structure	1.63	1.85	4.21	5.99			
	With hypothetical capital structure			2.06	2.93			
Sc	enario A, Add Soo Green, Benefit/Cost Ra	tios						
۸.		Total Resour	ce Perspective	RTO Pers	pective			
AS	set Owner Type	Without ITC	With ITC	Without ITC	With ITC			
In	vestor-Owned Financials	0.19	0.27	0.19	0.27			
Ρu	ıblic Power Financials							
	Without hypothetical capital structure	0.33	0.57	0.33	0.57			
	With hypothetical capital structure			0.19	0.27			
Sc	enario B, Add Power from the Prairie to So	cenario A, Benefit/Co	ost Ratios					
۸.		Total Resour	ce Perspective	RTO Perspective				
AS	set Owner Type	Without ITC	With ITC	Without ITC	With ITC			
In	vestor-Owned Financials	0.63	0.82	0.84	1.20			
Ρu	ıblic Power Financials							
	Without hypothetical capital structure	1.15	1.44	1.67	2.38			
	With hypothetical capital structure			0.82	1.16			



#### Exhibit V-7Z. Benefit/Cost Ratios Summary, All Scenarios (continued)

Scenario D, Add MP Connection to Scenario	B, Benefit/Cost Rati	OS				
Assat Owner Tuna	Total Resour	ce Perspective	RTO Perspective			
Asset Owner Type	Without ITC	With ITC	Without ITC	With ITC		
Investor-Owned Financials	0.56	0.76	1.05	1.49		
Public Power Financials						
Without hypothetical capital structure	1.00	1.15	2.24	3.19		
With hypothetical capital structure			1.10	1.56		

#### Scenario E, Add Utah CAES to Scenario B, Benefit/Cost Ratios

Accet Owner Type	Total Resour	ce Perspective	RTO Perspective				
Asset Owner Type	Without ITC	With ITC	Without ITC	With ITC			
Investor-Owned Financials	0.57	0.69	0.74	0.96			
Public Power Financials							
Without hypothetical capital structure	0.67	0.80	0.86	1.08			
With hypothetical capital structure			0.86	1.08			
Scenario E+. Add Utah H2 to Scenario B. Ben	efit/Cost Ratios						
B/C Ratios do not apply to Scenario E+.							

• Data for Scenario C is Confidential to the GCPSP Owners and is reported in their Volumes 3.



#### **EXHIBIT V-8. HUB LMPs BY SCENARIO**

Exhibit V-8A. Average Hub LMPs by Scenario, Tabular

Base Case																	
Hour	SPP_N	SPP_S	MISOARK	MISO IL Buses	MISOIND	MISOLOUS	MISOMICH	MN	MISOTEX	Wisconsin Hub	PJM N IL Buses	PJM Chicago Buses	PJM Dominion Buses	PJM Western Buses	CA_CISO	CA_LDWP	WECC
AVERAGE LMP	\$ 30.80	\$ 26.07	\$ 42.56	\$ 39.44	\$ 43.66	\$ 44.79	\$ 42.10	\$ 38.30	\$ 43.85	\$ 40.21	\$ 40.24	\$ 40.70	\$ 38.59	\$ 40.29	\$ 57.95	\$ 57.92	\$ 47.27
Scenario A																	
Hour	SPP_N	SPP_S	MISOARK	MISO IL Buses	MISOIND	MISOLOUS	MISOMICH	MN	MISOTEX	Wisconsin Hub	PJM N IL Buses	PJM Chicago Buses	PJM Dominion Buses	PJM Western Buses	CA_CISO	CA_LDWP	WECC
AVERAGE LMP	\$ 31.39	\$ 26.17	\$ 42.26	\$ 39.25	\$ 43.58	\$ 44.47	\$ 41.81	\$ 39.13	\$ 43.56	\$ 40.41	\$ 39.87	\$ 40.30	\$ 38.55	\$ 40.29	\$ 55.51	\$ 52.49	\$ 46.12
Change from Base Case (\$)	\$ 0.59	\$ 0.10	\$ (0.30)	\$ (0.19)	\$ (0.09)	\$ (0.31)	\$ (0.30)	\$ 0.83	\$ (0.29	)\$ 0.20	\$ (0.37)	\$ (0.40)	\$ (0.04)	\$ 0.01	\$ (2.44)	\$ (5.43)	\$ (1.15)
Change from Base Case (%)	1.9%	0.4%	-0.7%	-0.5%	-0.2%	-0.7%	-0.7%	2.2%	-0.7%	<b>0.5</b> %	-0.9%	-1.0%	-0.1%	0.0%	-4.2%	-9.4%	-2.4%
Scenario B																	
Hour	SPP_N	SPP_S	MISOARK	MISO IL Buses	MISOIND	MISOLOUS	MISOMICH	MN	MISOTEX	Wisconsin Hub	PJM N IL Buses	PJM Chicago Buses	PJM Dominion Buses	PJM Western Buses	CA_CISO	CA_LDWP	WECC
AVERAGE LMP	\$ 34.24	\$ 27.22	\$ 41.21	\$ 38.74	\$ 42.87	\$ 43.24	\$ 41.04	\$ 37.65	\$ 42.42	\$ 39.60	\$ 39.27	\$ 39.69	\$ 37.66	\$ 39.41	\$ 58.54	\$ 55.76	\$ 48.49
Change from Base Case (\$)	\$ 3.43	\$ 1.16	\$ (1.35)	\$ (0.70)	\$ (0.80)	\$ (1.55)	\$ (1.06)	\$ (0.65)	\$ (1.43	\$ (0.61	) \$ (0.97)	\$ (1.00)	\$ (0.94)	\$ (0.88)	\$ 0.59	\$ (2.16)	\$ 1.23
Change from Base Case (%)	11.1%	4.4%	-3.2%	-1.8%	-1.8%	-3.4%	-2.5%	-1.7%	-3.3%	-1.5%	-2.4%	-2.5%	-2.4%	-2.2%	1.0%	-3.7%	2.6%
Change from Scenario A (\$)	\$ 2.85	\$ 1.06	\$ (1.05)	\$ (0.51)	\$ (0.71)	\$ (1.23)	\$ (0.76)	\$ (1.49)	\$ (1.14	\$ (0.81	) \$ (0.61)	\$ (0.60)	\$ (0.90)	\$ (0.89)	\$ 3.03	\$ 3.27	\$ 2.38
Change from Scenario A (%)	9.1%	4.0%	-2.5%	-1.3%	-1.6%	-2.8%	-1.8%	-3.8%	-2.6%	-2.0%	-1.5%	-1.5%	-2.3%	-2.2%	5.5%	6.2%	5.2%
Scenario C																	
Hour	SPP_N	SPP_S	MISOARK	MISO IL Buses	MISOIND	MISOLOUS	MISOMICH	MN	MISOTEX	Wisconsin Hub	PJM N IL Buses	PJM Chicago Buses	PJM Dominion Buses	PJM Western Buses	CA_CISO	CA_LDWP	WECC
AVERAGE LMP	\$ 34.13	\$ 27.45	\$ 41.13	\$ 38.54	\$ 42.67	\$ 43.02	\$ 40.91	\$ 37.39	\$ 42.24	\$ 39.41	\$ 39.08	\$ 39.50	\$ 37.41	\$ 39.13	\$ 58.99	\$ 56.25	\$ 48.98
Change from Base Case (\$)	\$ 3.33	\$ 1.39	\$ (1.43)	\$ (0.90)	\$ (0.99)	\$ (1.77)	\$ (1.19)	\$ (0.91)	\$ (1.61	\$ (0.80)	) \$ (1.17)	\$ (1.20)	\$ (1.19)	\$ (1.15)	\$ 1.04	\$ (1.67)	\$ 1.72
Change from Base Case (%)	10.8%	5.3%	-3.4%	-2.3%	-2.3%	-3.9%	-2.8%	-2.4%	-3.7%	-2.0%	-2.9%	-2.9%	-3.1%	-2.9%	1.8%	-2.9%	3.6%
Change from Scenario B (\$)	\$ (0.11)	\$ 0.23	\$ (0.08)	\$ (0.20)	\$ (0.19)	\$ (0.22)	\$ (0.13)	\$ (0.26)	\$ (0.18	\$ (0.19)	) \$ (0.19)	\$ (0.20)	\$ (0.25)	\$ (0.27)	\$ 0.45	\$ 0.49	\$ 0.49
Change from Scenario B (%)	-0.4%	0.9%	-0.2%	-0.5%	-0.4%	-0.5%	-0.3%	-0.7%	-0.4%	-0.5%	-0.5%	-0.5%	-0.7%	-0.7%	0.8%	0.9%	1.0%
Scenario D																	
Hour	SPP N	SPP S	MISOARK	MISO IL Buses	MISOIND	MISOLOUS	MISOMICH	MN	MISOTEX	Wisconsin Hub	PJM N IL Buses	PJM Chicago Buses	PJM Dominion Buses	PJM Western Buses	CA CISO	CA LDWP	WECC
AVERAGE LMP	\$ 33.89	\$ 27.10	\$ 41.39	\$ 38.68	\$ 42.90	\$ 43.41	\$ 41.10	\$ 36.60	\$ 42.58	\$ 39.17	\$ 39.13	\$ 39.54	\$ 37.74	\$ 39.50	\$ 58.30	\$ 55.49	\$ 48.25
Change from Base Case (\$)	\$ 3.09	\$ 1.03	\$ (1.17)	\$ (0.76)	\$ (0.77)	\$ (1.38)	\$ (1.01)	\$ (1.70)	\$ (1.27	\$ (1.03)	\$ (1.11)	\$ (1.15)	\$ (0.86)	\$ (0.79)	\$ 0.35	\$ (2.44)	\$ 0.98
Change from Base Case (%)	10.0%	3.9%	-2.8%	-1.9%	-1.8%	-3.1%	-2.4%	-4.4%	-2.9%	-2.6%	-2.8%	-2.8%	-2.2%	-2.0%	0.6%	-4.2%	2.1%
Change from Scenario B (\$)	\$ (0.34)	\$ (0.13)	\$ 0.18	\$ (0.06)	\$ 0.03	\$ 0.17	\$ 0.05	\$ (1.04)	\$ 0.16	\$ (0.43)	) \$ (0.14)	\$ (0.15)	\$ 0.08	\$ 0.09	\$ (0.24)	\$ (0.27)	\$ (0.25)
Change from Scenario B (%)	-1.0%	-0.5%	0.4%	-0.2%	0.1%	0.4%	0.1%	-2.8%	0.4%	-1.1%	-0.4%	-0.4%	0.2%	0.2%	-0.4%	-0.5%	-0.5%
Scenario E																	
Hour	SPP_N	SPP_S	MISOARK	MISO IL Buses	MISOIND	MISOLOUS	MISOMICH	MN	MISOTEX	Wisconsin Hub	PJM N IL Buses	PJM Chicago Buses	PJM Dominion Buses	PJM Western Buses	CA_CISO	CA_LDWP	WECC
AVERAGE LMP	\$ 34.19	\$ 27.23	\$ 41.25	\$ 38.73	\$ 42.86	\$ 43.25	\$ 41.02	\$ 37.62	\$ 42.44	\$ 39.59	\$ 39.26	\$ 39.68	\$ 37.66	\$ 39.43	\$ 58.39	\$ 55.58	\$ 48.38
Change from Base Case (\$)	\$ 3.38	\$ 1.16	\$ (1.32)	\$ (0.71)	\$ (0.81)	\$ (1.53)	\$ (1.08)	\$ (0.68)	\$ (1.42	\$ (0.62)	\$ (0.98)	\$ (1.01)	\$ (0.93)	\$ (0.86)	\$ 0.43	\$ (2.34)	\$ 1.11
Change from Base Case (%)	11.0%	4.5%	-3.1%	-1.8%	-1.9%	-3.4%	-2.6%	-1.8%	-3.2%	-1.5%	-2.4%	-2.5%	-2.4%	-2.1%	0.8%	-4.0%	2.4%
Change from Scenario B (\$)	\$ (0.05)	\$ 0.00	\$ 0.04	\$ (0.01)	\$ (0.01)	\$ 0.01	\$ (0.02)	\$ (0.03)	\$ 0.01	\$ (0.01	) \$ (0.01)	\$ (0.01)	\$ 0.00	\$ 0.02	\$ (0.15)	\$ (0.18)	\$ (0.11)
Change from Scenario B (%)	-0.2%	0.0%	0.1%	0.0%	0.0%	0.0%	-0.1%	-0.1%	0.0%	6 0.0%	6 0.0%	0.0%	0.0%	. 0.0%	-0.3%	-0.3%	-0.2%
Scenario E+																	
Hour	SPP_N	SPP_S	MISOARK	MISO IL Buses	MISOIND	MISOLOUS	MISOMICH	MN	MISOTEX	Wisconsin Hub	PJM N IL Buses	PJM Chicago Buses	PJM Dominion Buses	PJM Western Buses	CA_CISO	CA_LDWP	WECC
AVERAGE LMP	\$ 34.25	\$ 27.24	\$ 41.24	\$ 38.73	\$ 42.85	\$ 43.24	\$ 41.03	\$ 37.65	\$ 42.43	\$ 39.60	\$ 39.27	\$ 39.69	\$ 37.68	\$ 39.44	\$ 58.68	\$ 55.95	\$ 48.59
Change from Base Case (\$)	\$ 3.44	\$ 1.17	\$ (1.32)	\$ (0.70)	\$ (0.81)	\$ (1.54)	\$ (1.07)	\$ (0.65)	\$ (1.42	\$ (0.61)	) \$ (0.97)	\$ (1.00)	\$ (0.91)	\$ (0.85)	\$ 0.73	\$ (1.97)	\$ 1.32
Change from Base Case (%)	11.2%	4.5%	-3.1%	-1.8%	-1.9%	-3.4%	-2.5%	-1.7%	-3.2%	-1.5%	-2.4%	-2.5%	-2.4%	-2.1%	1.3%	-3.4%	2.8%
Change from Scenario B (\$)	\$ 0.01	\$ 0.01	\$ 0.03	\$ (0.00)	\$ (0.01)	\$ 0.00	\$ (0.01)	\$ (0.00)	\$ 0.01	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.02	\$ 0.03	\$ 0.14	\$ 0.19	\$ 0.09
Change from Scenario B (%)	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	6 0.0%	6 0.0%	0.0%	0.1%	0.1%	0.2%	0.3%	0.2%



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#### Exhibit V-8B. Average Hub LMPs by Scenario, Graphical



- Average LMPs lowest in SPP, highest in California. ٠
- PftP and GCPSP decrease LMPs compared to Scenario A at most Hubs. ٠
  - But increase LMPs in SPP, WECC, and California (by reducing hours of negative LMPs). 0



## Exhibit V-8C. Hours of Negative LMPs by Scenario, Tabular

Base Case																	
Hour	SPP_N	SPP_S	MISOARK	MISO IL Buses	MISOIND	MISOLOUS	MISOMICH	MN	MISOTEX	Wisconsin Hub	PJM N IL Buses	PJM Chicago Buses	PJM Dominion Buses	PJM Western Buses	CA_CISO	CA_LDWP	WECC
Hours LMP < 0	389	948	11	0	(	0 1	0	27	0	1	0 0	0	٥	0	575	370	274
Scenario A																	
Hour	SPP_N	SPP_S	MISOARK	MISO IL Buses	MISOIND	MISOLOUS	MISOMICH	MN	MISOTEX	Wisconsin Hub	PJM N IL Buses	PJM Chicago Buses	PJM Dominion Buses	PJM Western Buses	CA_CISO	CA_LDWP	WECC
Hours LMP < 0	283	935	11	0	(	0 2	0	13	0	)	0 0	0	0	0	598	545	308
Change from Base Case (Hours)	(106)	(13)	-	-	-	1	-	(14)		-	-	-	-	-	23	175	34
Change from Base Case (%)	-27.2%	-1.4%	0.0%	-		- 100.0%	-	-51.9%	-			-	-	-	4.0%	47.3%	12.4%
Scenario B																	
Hour	SPP_N	SPP_S	MISOARK	MISO IL Buses	MISOIND	MISOLOUS	MISOMICH	MN	MISOTEX	Wisconsin Hub	PJM N IL Buses	PJM Chicago Buses	PJM Dominion Buses	PJM Western Buses	CA_CISO	CA_LDWP	WECC
Hours LMP < 0	136	624	9	0		0 2	0	18	0	)	o c	0 0	0	0	411	270	182
Change from Base Case (Hours)	(253.0)	(324.0)	(2.0)	-		1.0	-	(9.0)	-	-	-	-	-		(164.0)	(100.0)	(92.0)
Change from Base Case (%)	-65.0%	-34.2%	-18.2%	-		- 100.0%	-	-33.3%				-	-	-	-28.5%	-27.0%	-33.6%
Change from Scenario A (Hours)	(147)	(311)	(2)	-	-	-	-	5	-	-	-	-	-		(187)	(275)	(126)
Change from Scenario A (%)	-51.9%	-33.3%	-18.2%			- 0.0%	-	38.5%	-			-	-	-	-31.3%	-50.5%	-40.9%
Scenario C																	
Hour	SPP N	SPP S	MISOARK	MISO IL Buses	MISOIND	MISOLOUS	MISOMICH	MN	MISOTEX	Wisconsin Hub	PJM N IL Buses	PJM Chicago Buses	PJM Dominion Buses	PJM Western Buses	CA CISO	CA LDWP	WECC
Hours LMP < 0	131	572	13	0		0 6	0	16	0		0 0	0 0	0	0	393	255	153
Change from Base Case (Hours)	(258.00)	(376.00)	2.00	-	-	5.00	-	(11.00)	-	-	-	-	-	-	(182.00)	(115.00)	(121.00)
Change from Base Case (%)	-66.3%	-39.7%	18.2%	-		- 500.0%	-	-40.7%	-			-	-		-31.7%	-31.1%	-44.2%
Change from Scenario B (Hours)	(5.00)	(52.00)	4.00	-	-	4.00	-	(2.00)		-	-	-	-	-	(18.00)	(15.00)	(29.00)
Change from Scenario B (%)	-1.3%	-5.5%	36.4%	-		- 400.0%	-	-7.4%	-			-	-	-	-3.1%	-4.1%	-10.6%
Scenario D																	
Hour	SPP N	SPP S	MISOARK	MISO IL Buses	MISOIND	MISOLOUS	мізомісн	MN	MISOTEX	Wisconsin Hub	PJM N IL Buses	PJM Chicago Buses	PJM Dominion Buses	PJM Western Buses	CA CISO	CA LDWP	WECC
Hours LMP < 0	151	633	14	0		0 5	0	25	0		0 0	0	0	0	417	270	188
Change from Base Case (Hours)	(238)	(315)	3	-		4	-	(2)		-					(158)	(100)	(86)
Change from Base Case (%)	-61.2%	-33.2%	27.3%	-		- 400.0%	-	-7.4%	-				-		-27.5%	-27.0%	-31.4%
Change from Scenario B (Hours)	15.00	9.00	5.00	-	-	3.00	-	7.00	-	-	-		-		6.00	-	6.00
Change from Scenario B (%)	11.0%	1.4%	55.6%	-		- 150.0%	-	38.9%	-	•		-	-	-	1.5%	0.0%	3.3%
Scenario E																	
Hour	SPP N	SPP S	MISOARK	MISO IL Buses	MISOIND	MISOLOUS	MISOMICH	MN	MISOTEX	Wisconsin Hub	PJM N IL Buses	PJM Chicago Buses	PJM Dominion Buses	PJM Western Buses	CA CISO	CA LDWP	WECC
Hours LMP < 0	128	- 637	11	0	(	0 2	0	18	0	)	o c	0 0	0	0	384		165
Change from Base Case (Hours)	(261.00)	(311.00)	-	-	-	1.00	-	(9.00)	-	-	-	-	-	-	(191.00)	(125.00)	(109.00)
Change from Base Case (%)	-67.1%	-32.8%	0.0%			100.0%		-33.3%							-33.2%	-33.8%	-39.8%
Change from Scenario B (Hours)	(8.00)	13.00	2.00	-	-	-	-	-	-	-	-	-	-	-	(27.00)	(25.00)	(17.00)
Change from Scenario B (%)	-5.9%	2.1%	22.2%			0.0%		0.0%							-6.6%	-9.3%	-9.3%
Scenario E+																	
Hour	SPP N	SPP S	MISOARK	MISO IL Buses	MISOIND	MISOLOUS	MISOMICH	MN	MISOTEX	Wisconsin Hub	PJM N IL Buses	PJM Chicago Buses	PJM Dominion Buses	PJM Western Buses	CA CISO	CA LDWP	WECC
Hours LMP < 0	135	615	12	0	(	0 3	0	18	0	) (	0 0	0	0	0	415	274	184
Change from Base Case (Hours)	(254.00)	(333,00)	1.00		-	2.00		(9,00)		-	-	-	-	-	(160,00)	(96,00)	(90,00)
Change from Base Case (%)	-65.3%	-35,1%	9.1%			200.0%		-33.3%							-27,8%	-25.9%	-32.8%
Change from Scenario B (Hours)	(1.00)	(9,00)	3.00	-	-	1.00	-	-		-	-	-	-	-	4,00	4,00	2,00
Change from Scenario B (%)	-0.7%	-1.4%	33.3%			50.0%		0.0%							1.0%	1.5%	1.1%



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Exhibit V-8D. Hours of Negative LMP by Scenario, Graphical



- Negative LMPs observed in SPP and California, which have the lowest and highest average LMPs, respectively. ٠
- Scenario A increases hours of negative LMPs in California, by adding more renewables to the mix.
- PftP (Scenario B) significantly reduces hours of negative LMPs compared to Base Case and Scenario A.
- By providing new markets for what otherwise would be renewables over-generation compared to load. •
- Once PftP in place, subsequent Scenarios do not change the picture much (although GCPSP shows additional benefits).



#### **EXHIBIT V-9. STORAGE FACILITIES PERFORMANCE**

Exhibit V-9A. Scenario C: GCPSP Performance



- Optimized GCPSP dispatch keeps upper storage reservoir operating within its capacity limits.
- CF1 = capacity factor during hours when generating or pumping.
- CF2 = capacity factor including all hours of the year.




#### Exhibit V-9B. Scenario E: Utah CAES Performance

- Optimized CAES dispatch keeps underground storage reservoir operating within its capacity limits. ٠
- CF1 = capacity factor during hours when generating or pumping. •
- CF2 = capacity factor including all hours of the year. .
- Storage activity greatest during first half of the year. Similar to effects shown on PftP line during first half of year. .



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### Exhibit V-9C. Scenario E+: Utah Hydrogen Electrolyzer Performance



• The electrolyzer was assumed to have a 210 MW peak input demand, and a load pattern similar to the flow inbound to Delta, UT on the TransWest Express HVDC line in Scenario B, with a 77.3% annual load factor.



## Exhibit V-10. EXAMPLE CDS NON-PARTICIPANT PRODUCTION COSTS, CARBON, AND CURTAILMENT (CONFIDENTIAL)

This Exhibit V-10 is Confidential to the CDS Participants. It is provided in Volume 3 of this Report for each Participant.

## Exhibit V-12. PERFORMANCE OF CDS PARTICIPANTS' GENERATION OF INTEREST (CONFIDENTIAL)

This Exhibit V-12 is Confidential to the CDS Participants. It is provided in Volume 3 of this Report for each Participant.

