POWER FROM THE PRAIRIE

Concept Development Study (CDS)

Volume 2:
Exhibits
PUBLIC EDITION

March 23, 2023

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INTERREGIONAL 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, www.powerfromtheprairie.com) 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,

Bob Schulte
Managing Member

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II. EXHIBITS

##

EXHIBIT III-1. THE CDS PARTICIPANTS

The CDS Participants

- Basin Electric Power Cooperative
  - Wholesale supplier to 3M cooperative utility customers in 9 states.
- Berkshire Hathaway Energy (BHE)
  - Represented by their affiliate, U.S. Transmission.
  - CDS results for their three regulated utilities.
- Black Hills Corporation (BHC)
  - CDS results for their three regulated utilities.

A diverse coalition of municipal, cooperative and investor-owned utilities and developers participating.

EXHIBIT III-1. THE CDS PARTICIPANTS (continued)

The CDS Participants (continued)

- Minnesota Power
  - Investor-owned utility serving 15 municipalities in Minnesota, and some of the largest industrial customers in the nation (Taconite).
  - Connections to ND wind and Manitoba hydro energy.

- Missouri River Energy Services (MRES)
  - Wholesale supplier to 61 municipal utilities in four states.
  - Holds Gregory County pumped storage FERC preliminary permit.

A diverse coalition of municipal, cooperative and investor-owned utilities and developers participating.

EXHIBIT III-1. THE CDS PARTICIPANTS (continued)

CDS Participants (continued)

- Omaha Public Power District (OPPD)
  - Part of their decarbonization plans.

your energy partner
OPPD
Omaha Public Power District

- Southern California Public Power Authority (SCPPA)
  - Represented by member Burbank Water & Power.
  - Participant in existing 2,400 MW Southern Transmission System HVDC line.

SCPPA
SOUTHERN CALIFORNIA Public Power Authority

POWER FROM THE PRAIRIE LLC

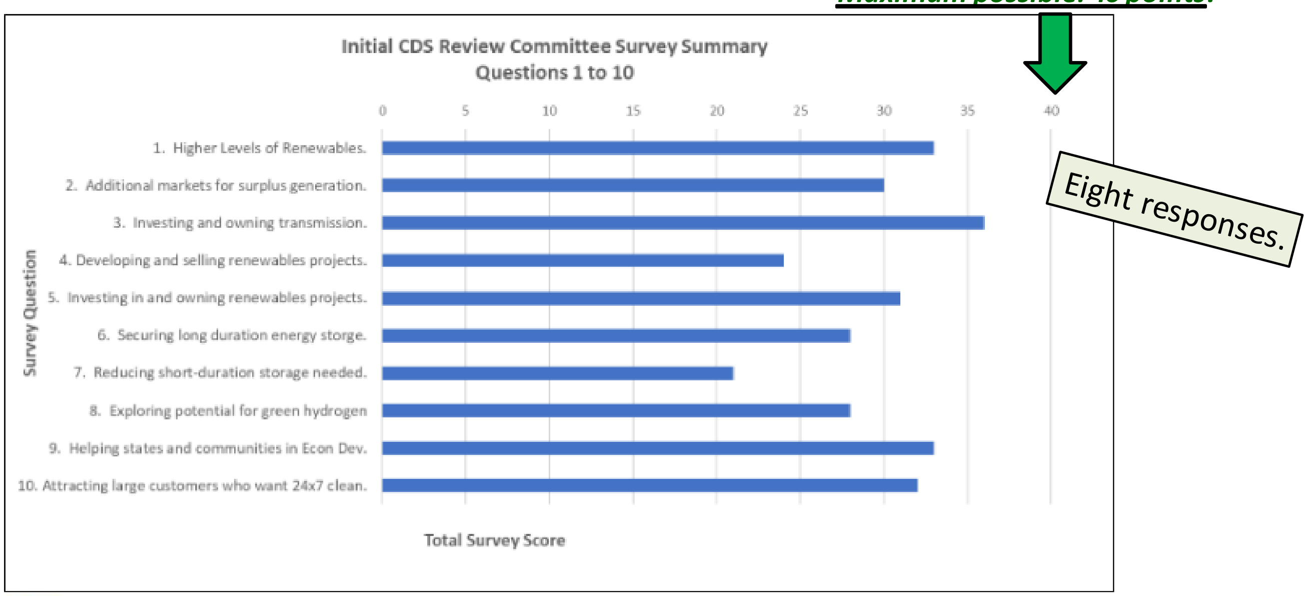
A diverse coalition of municipal, cooperative and investor-owned utilities and developers participating.

EXHIBIT III-2. INITIAL POLL OF CDS PARTICIPANTS

Initial Review Committee Survey: Results

(Extremely Important = 5 points. Not Important = 1 point)

Maximum possible: 40 points.



Primary motivations are transmission ownership and higher renewables.
Also interests in helping economic development and new customers who want 24x7 renewables.

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

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

<u>Two responses:</u>

"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."

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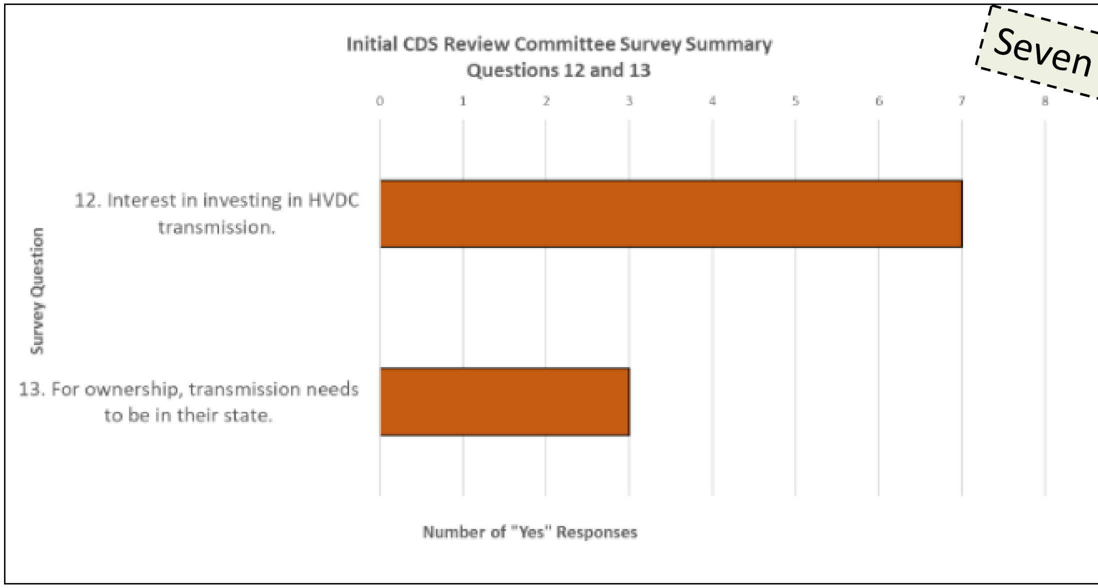
EXHIBIT III-2. INITIAL POLL OF CDS PARTICIPANTS (continued)

Initial Survey Results (continued)

(Utility Participants only)



Seven responses

All utility Participant respondents are interested in owning HVDC.
Most are are OK if the HVDC they ownis located inanother state. 4

EXHIBIT III-3: CDS REVIEW COMMITTEE AND SUBCOMMITTEES

Exhibit III-3A. CDS Review Committee

Participant	Name	Title
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

Exhibit III-3B. CDS Task 1 (Modeling) Subcommittee

Participant	Name	Title
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	Title
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	Title
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

Participant	Name	Title
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

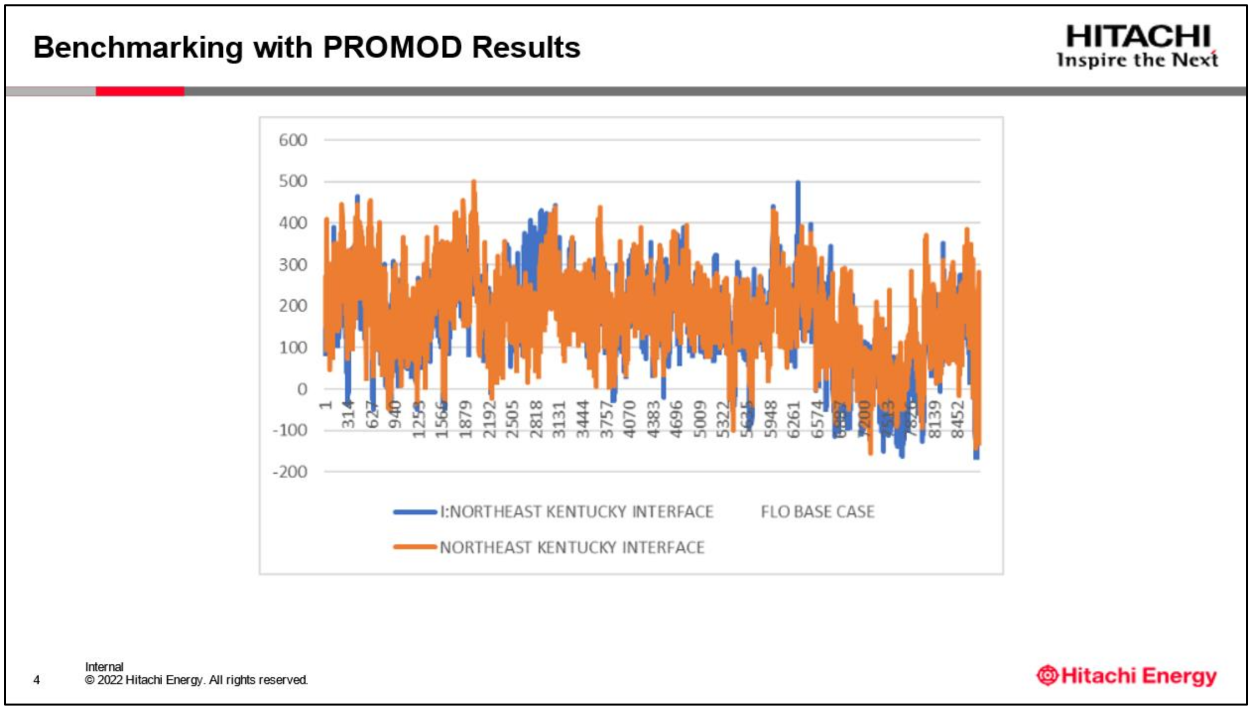


Exhibit V-1B. Comparison of PROMOD and Gridview results, graphical

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

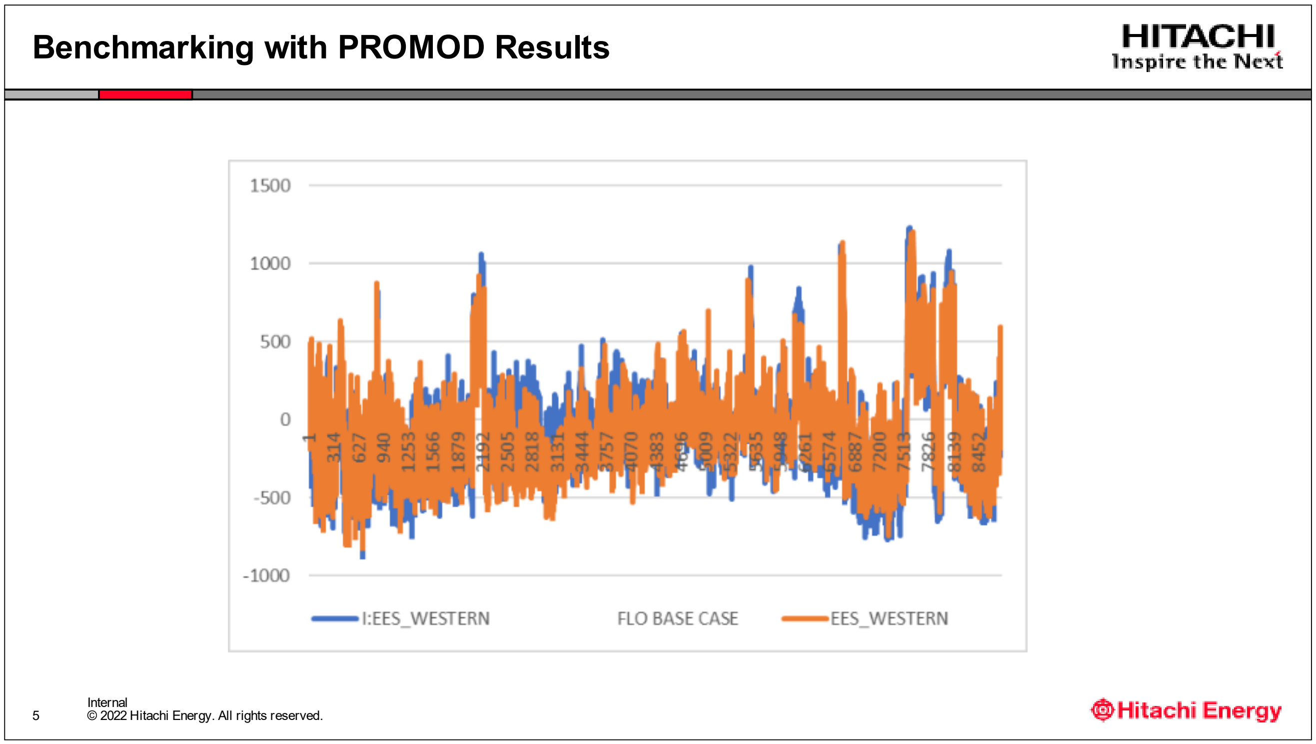


Exhibit V-1C. Comparison of PROMOD and Gridview results, graphical

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

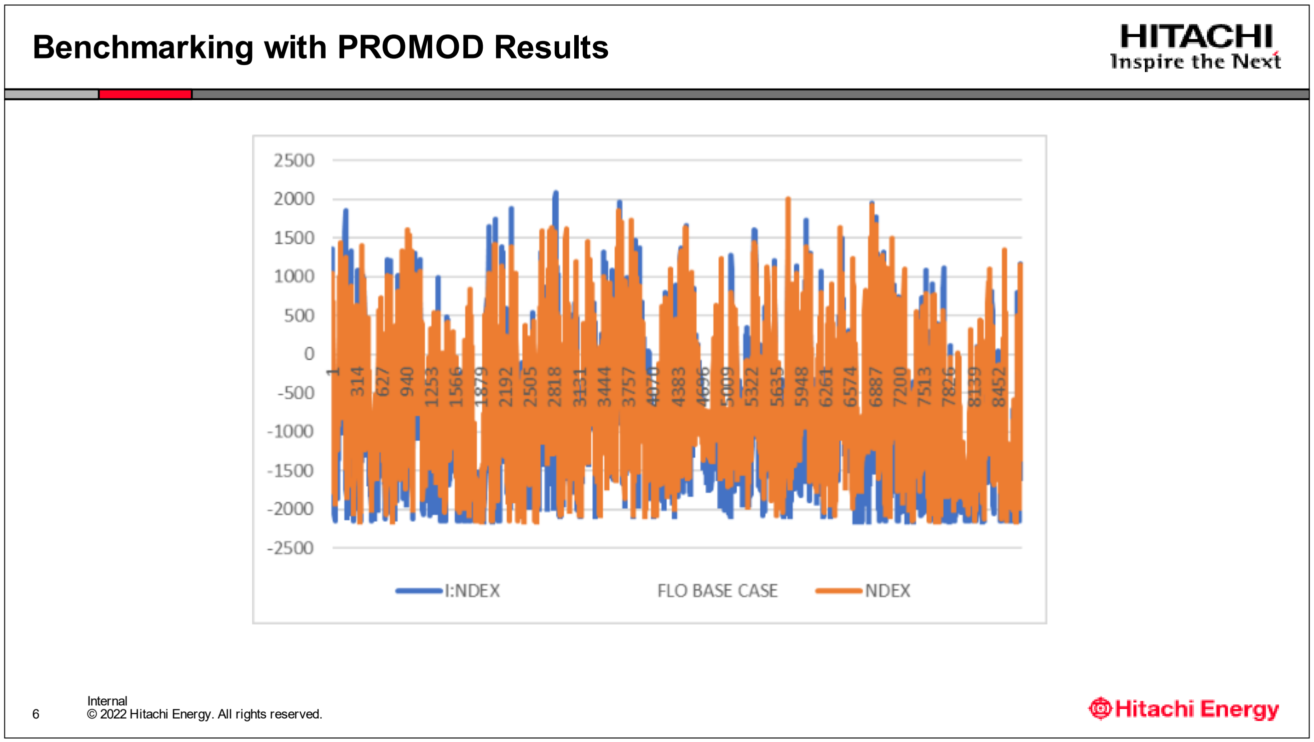


Exhibit V-1D. Comparison of PROMOD and Gridview results, tabular

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

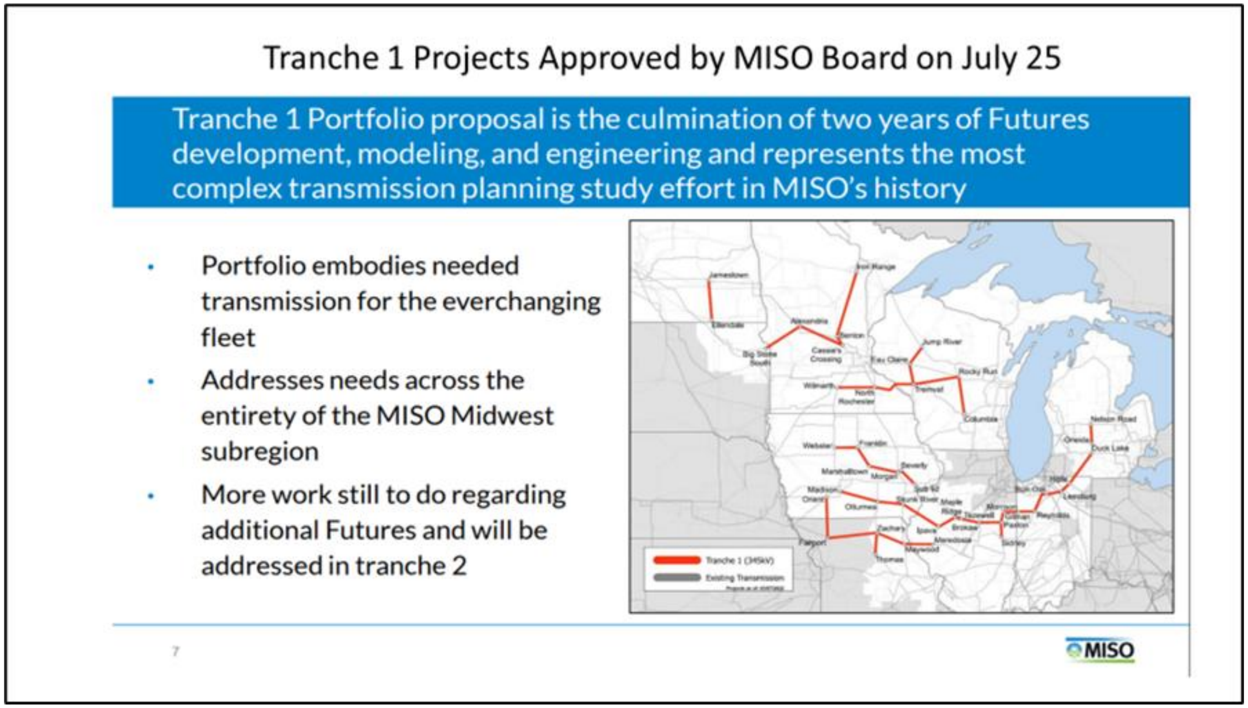
Row Labels	Sum of Promod	Sum of GridView
⊞ **MHEB**	**37,909,057**	**36,829,313**
⊟ **MISO**	**744,720,716**	**729,461,612**
CC	330,154,892	318,749,477
CT Gas	35,198,336	28,835,328
CT Oil	4,237	6,783
CT Other	16,536	16,357
CT Renewable	55,558	55,538
Geothermal	37,430	41,739
IC Gas	1,278,414	1,238,815
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 Hydro	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**
⊞ **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	-
⊞ **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**

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

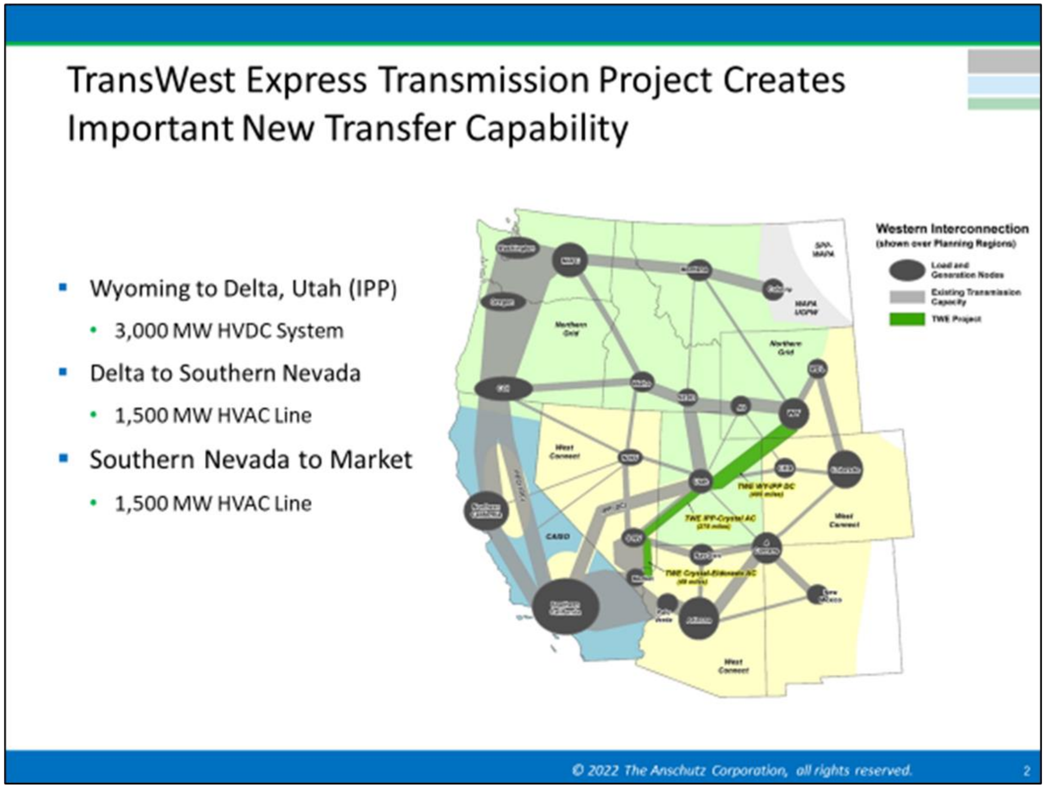
EXHIBIT V-2. DEFINING THE DC AND AC TRANSMISSION LAYOUTS

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

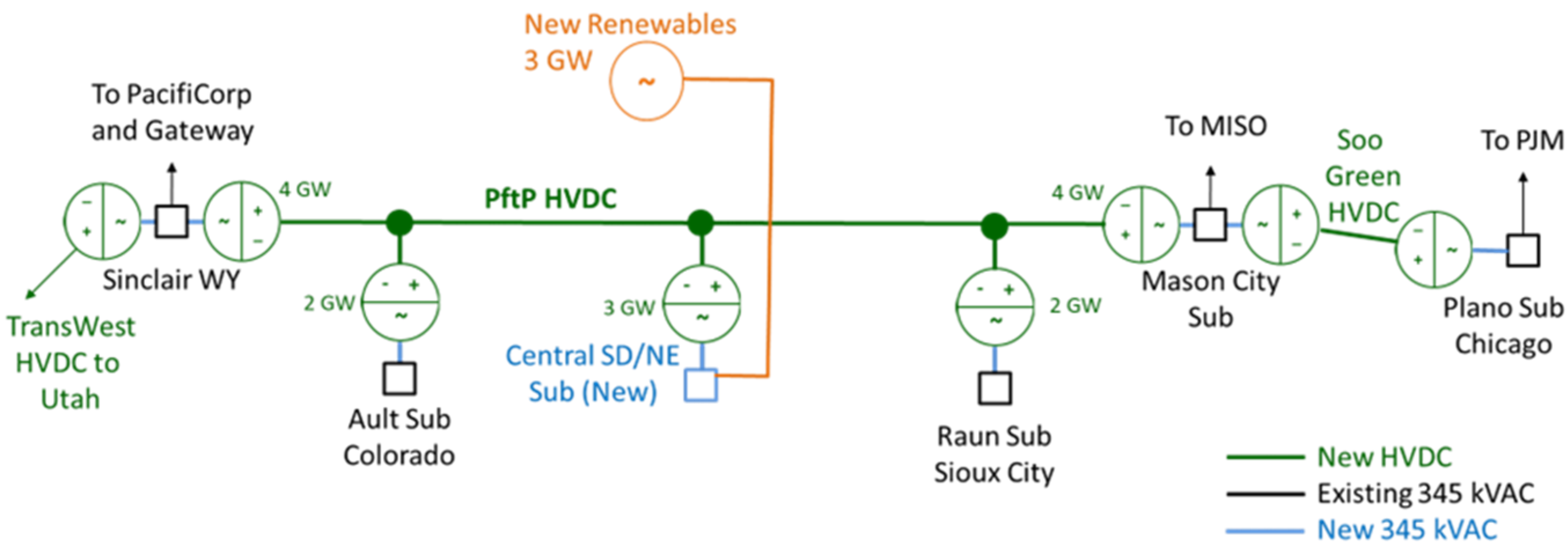


- TransWest plans a 3,000 MW HVDC line from Wyoming to IPP site at Delta, Utah. There, it connects to the Southern Transmission system 2,400 MW HVDC line to Southern California, and also continues from Delta to Nevada via a TransWest 500 KVAC development.

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.

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)

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

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

Overhead DC Transmission Line Cost Conceptual Estimate
(in 2022$)

- Using $3,400,000/mile:

– Sinclair to Ault	187 miles	$635,800,000
– Ault to Central SD/NE	336 miles	$1,142,400,000
– Central SD/NE to Raun	171 miles	$581,400,000
– Raun to Mason City	147 miles	$499,800,000
Total		$2,859,400,000

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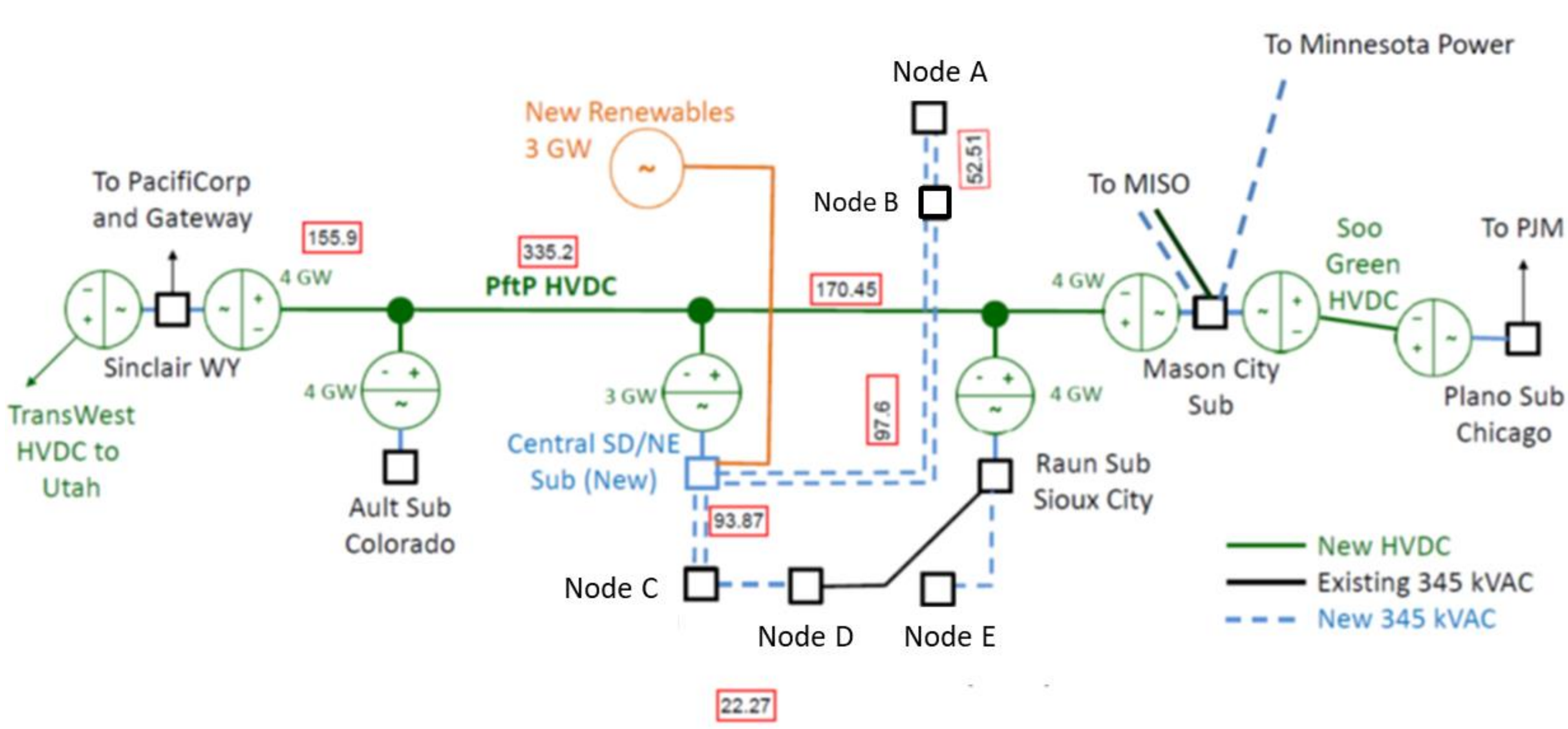
Like all other assumptions, these costs are subject to review and optimization during Stage 2 of the Project.

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.

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

Line Segment/Station	Length (Miles)	Line/Station Cost	ROW Land	Total (2022$)	2030$ @ 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						**$ 2,084,824,588**

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.

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

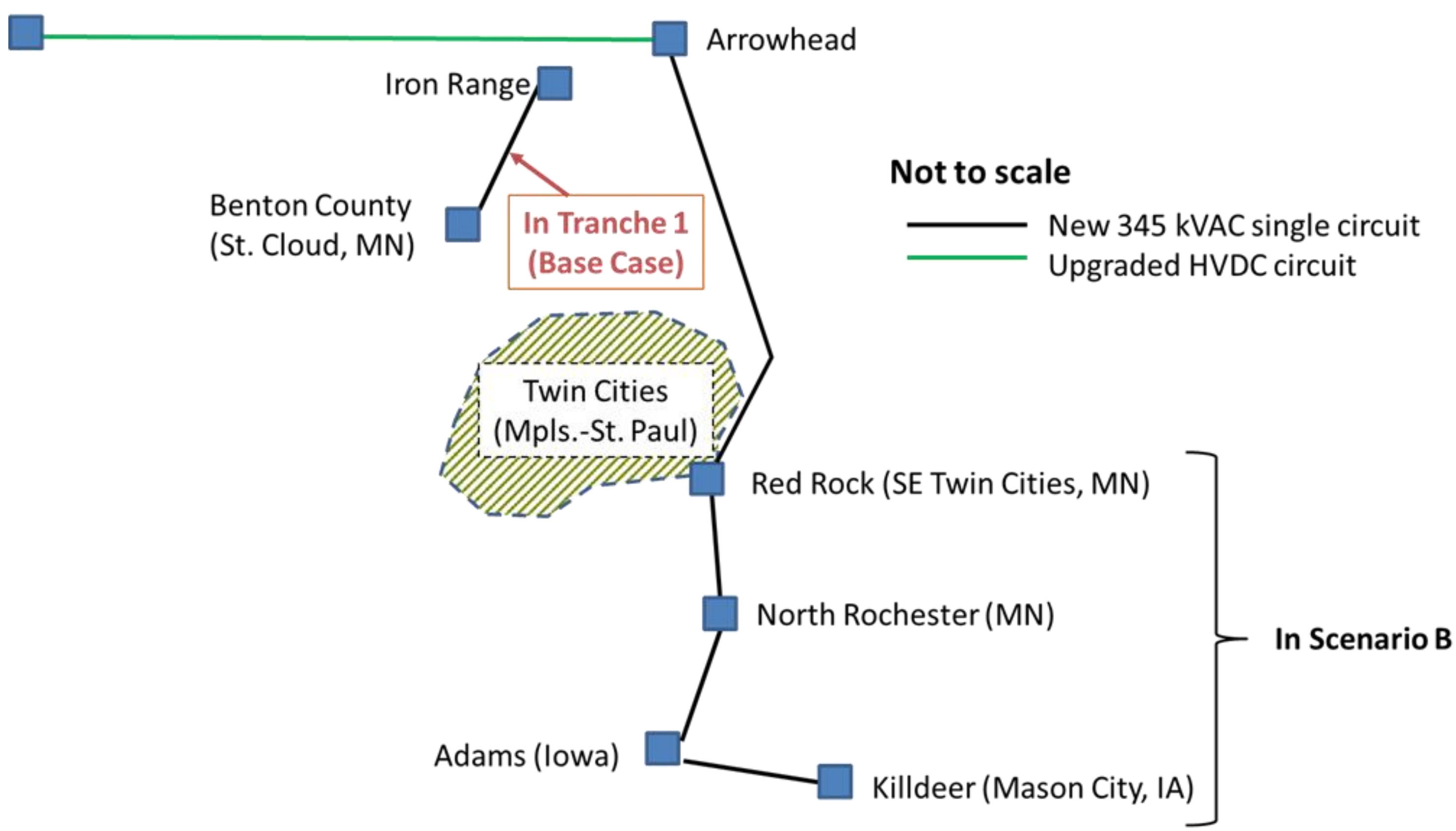


Exhibit V-2G2: Scenario E: Minnesota Connection HVDC Conversion Costs

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	$ 100,000,000
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 Case

		Energy (Annual MWh)			Adjusted Production Cost, APC (Annual $M)				Renewables curtailment	Carbon Emissions	Renewables 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 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.

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

Scenario A

		Energy (Annual MWh)			Adjusted Production Cost, APC (Annual $M)				Renewables curtailment	Carbon Emissions	Renewables 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 without 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 Case

		Energy (Annual MWh)			Adjusted Production Cost, APC (Annual $M)				Renewables curtailment	Carbon Emissions	Renewables 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 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**

Scenario A change from Base Case

		Energy (Annual MWh)			Adjusted Production Cost, APC (Annual $M)				Renewables curtailment	Carbon Emissions	Renewables 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	$ (720)	$ 1	$ (2)	$ (717)	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 without 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)**

- 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)

Scenario A+

		Energy (Annual MWh)			Adjusted Production Cost, APC (Annual $M)				Renewables curtailment	Carbon Emissions	Renewables 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	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 without double-counting CAISO		3,059,545,948	24,011,339	58,071,857	67,322	1,049	2,130	66,242	25,592,512	669,374,649	800,895,546	24,088,395

Scenario A

		Energy (Annual MWh)			Adjusted Production Cost, APC (Annual $M)				Renewables curtailment	Carbon Emissions	Renewables 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	$ 16,200.47	$ 801.79	$ 60.16	16942.52	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	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	$ 166.91	$ 6.89	19234.38	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
Totals without 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

Scenario A+ Change from Scenario A

		Energy (Annual MWh)			Adjusted Production Cost, APC (Annual $M)				Renewables curtailment	Carbon Emissions	Renewables 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	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 without double-counting CAISO		37,076	#VALUE!	(979,891)	$ (16.51)	$ (41.84)	$ (42.56)	$ (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)

Scenario B

		Energy (Annual MWh)			Adjusted Production Cost, APC (Annual $M)				Renewables curtailment	Carbon Emissions	Renewables 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 without 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**

Scenario A

		Energy (Annual MWh)			Adjusted Production Cost, APC (Annual $M)				Renewables curtailment	Carbon Emissions	Renewables 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 without 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**

Scenario B change from Scenario A

		Energy (Annual MWh)			Adjusted Production Cost, APC (Annual $M)				Renewables curtailment	Carbon Emissions	Renewables 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	PJM 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)	$ (762)	$ (14)	$ (1)	$ (776)	(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 without 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)

Scenario B+ (Double Soo Green)

		Energy (Annual MWh)			Adjusted Production Cost, APC (Annual $M)				Renewables curtailment	Carbon Emissions	Renewables 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	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 without 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**

Scenario B

		Energy (Annual MWh)			Adjusted Production Cost, APC (Annual $M)				Renewables curtailment	Carbon Emissions	Renewables 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 without 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**

Scenario B+ changes from Scenario B

		Energy (Annual MWh)			Adjusted Production Cost, APC (Annual $M)				Renewables curtailment	Carbon Emissions	Renewables 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	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	$ 1	$ (0)	$ 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 without 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.

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

Scenario D

	Region	Energy (Annual MWh) Generation	Purchases	Sales	Adjusted Production Cost, APC (Annual $M) Fuel Cost	Purchase Cost	Sales Revenue	Total APC	Renewables curtailment (Annual MWh)	Carbon Emissions (Annual metric Tons)	Renewables Facilities 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 without 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

Scenario B

	Region	Energy (Annual MWh) Generation	Purchases	Sales	Adjusted Production Cost, APC (Annual $M) Fuel Cost	Purchase Cost	Sales Revenue	Total APC	Renewables curtailment (Annual MWh)	Carbon Emissions (Annual metric Tons)	Renewables Facilities 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 without 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

Scenario D change from Scenario B

	Region	Energy (Annual MWh) Generation	Purchases	Sales	Adjusted Production Cost, APC (Annual $M) Fuel Cost	Purchase Cost	Sales Revenue	Total APC	Renewables curtailment (Annual MWh)	Carbon Emissions (Annual metric Tons)	Renewables Facilities 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

- 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)

Scenario E_Utah CAES

		Energy (Annual MWh)			Adjusted Production Cost, APC (Annual $M)				Renewables curtailment	Carbon Emissions	Renewables 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 without 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**

Scenario B

		Energy (Annual MWh)			Adjusted Production Cost, APC (Annual $M)				Renewables curtailment	Carbon Emissions	Renewables 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 without 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**

Scenario E change from Scenario B

		Energy (Annual MWh)			Adjusted Production Cost, APC (Annual $M)				Renewables curtailment	Carbon Emissions	Renewables Facilities	
	Region	Generation	Purchases	Sales	Fuel Cost	Purchase Cost	Sales Revenue	Total APC	(Annual MWh)	(Annual metric Tons)	Annual Output (MWh)	Curtailment (Annual MWh)
1	MISO	(399,292)	(7,840)	2,298	(16)	(1)	0	(17)	(11,785)	(285,254)	11,637	(11,638)
2	PJM Interconnection	(62,325)	-	(50,040)	(3)	-	(2)	(1)	10,366	(30,663)	(10,286)	10,286
3	SPP	4,946	(15,804)	(3,058)	(0)	(1)	(0)	(0)	(2,731)	(63,197)	707	(707)
4	WECC	442,783	(40,881)	(11,056)	(232)	(3)	0	(159)	(189,400)	(1,085,637)	4,352,649	(148,446)
5	CA_CISO	(792,270)	1,013,685	219,708	(67)	53	9	(22)	(23,614)	(331,269)	5,328	(5,328)
Totals without double-counting CAISO		**(13,888)**	**(64,525)**	**(61,856)**	**$ (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.

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

Scenario E+

	Region	Energy (Annual MWh) Generation	Purchases	Sales	Adjusted Production Cost, APC (Annual $M) Fuel Cost	Purchase Cost	Sales Revenue	Total APC	Renewables curtailment (Annual MWh)	Carbon Emissions (Annual metric Tons)	Renewables Facilities Annual Output (MWh)	Curtailment (Annual MWh)
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
Totals without 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

Scenario B

	Region	Energy (Annual MWh) Generation	Purchases	Sales	Adjusted Production Cost, APC (Annual $M) Fuel Cost	Purchase Cost	Sales Revenue	Total APC	Renewables curtailment (Annual MWh)	Carbon Emissions (Annual metric Tons)	Renewables Facilities 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 without 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

Scenario E+ changes from Scenario B

	Region	Energy (Annual MWh) Generation	Purchases	Sales	Adjusted Production Cost, APC (Annual $M) Fuel Cost	Purchase Cost	Sales Revenue	Total APC	Renewables curtailment (Annual MWh)	Carbon Emissions (Annual metric Tons)	Renewables Facilities Annual Output (MWh)	Curtailment (Annual MWh)
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	$ 1	$ (0)	$ 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 without double-counting CAISO		(42,675)	31,698	19,458	$ 72	$ 1	$ 1	$ 72	(789)	539,053	(1,423,837)	2,671

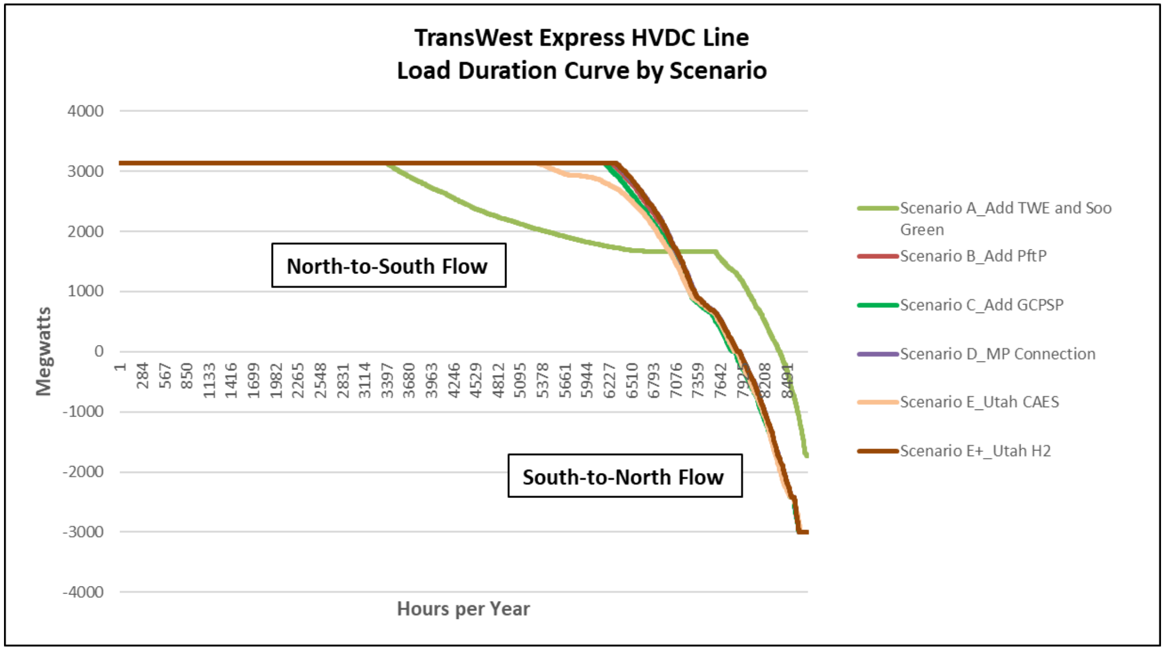
- In contrast to the other Scenarios, Utah H2 with PftP (Scenario E+) represents an added *load* rather than added renewable generation.
- It results in a regional production cost *increase* of $72 million in Year 2030, and an increase in annual carbon emissions of about 539,000 metric tons.

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.

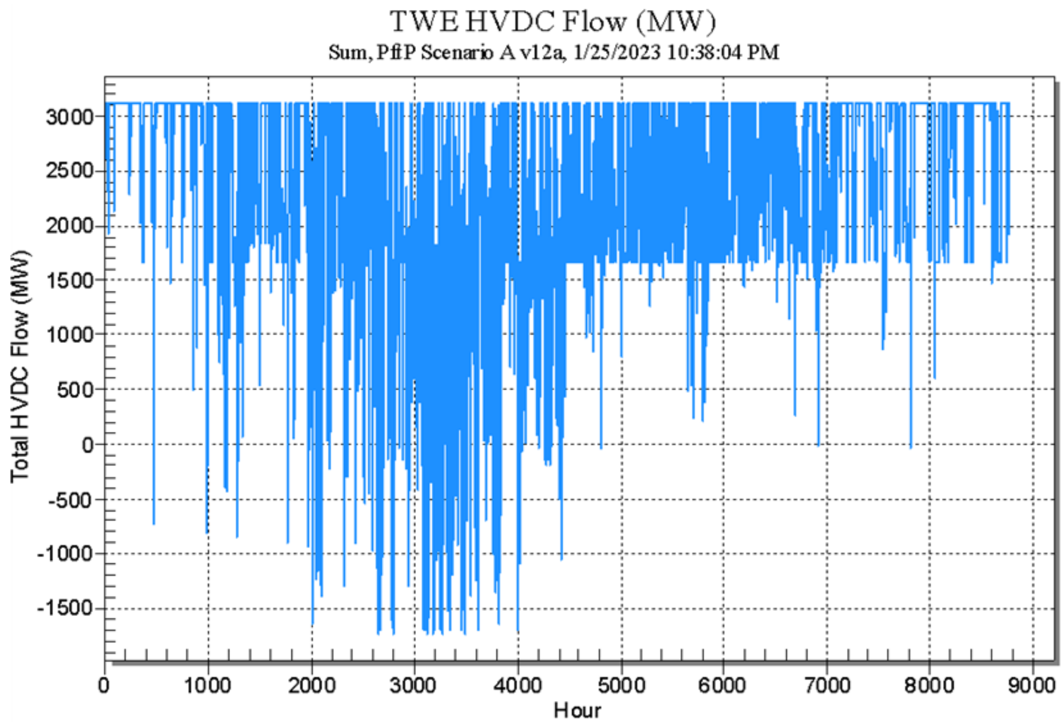
EXHIBIT V-5. TASK 1: TRANSMISSION FACILITIES PERFORMANCE BY SCENARIO

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



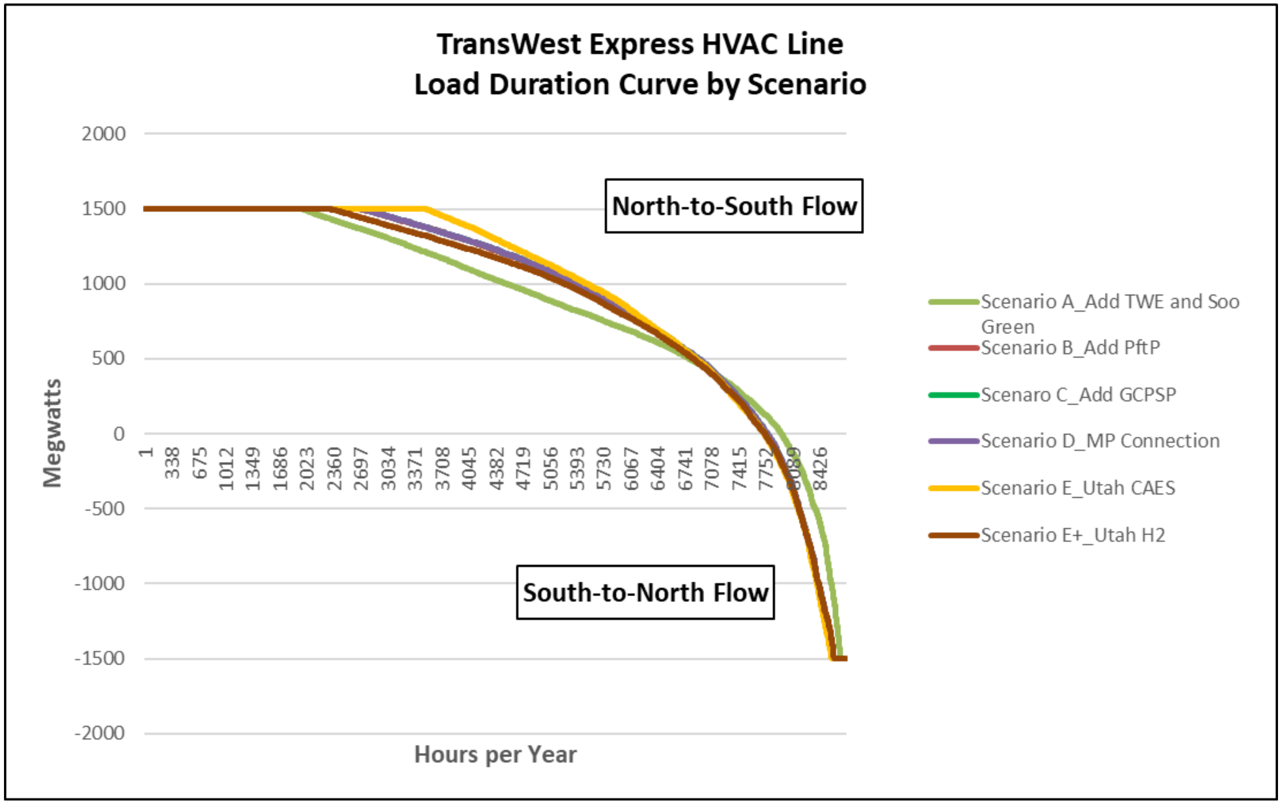
- PftP increases flows on TransWest HVDC in both directions.
- TWE South-to-North peak flow in Scenario A limited by transformer connection at PacifiCorp, and by lack of other loads to the North.
- Addition of PftP in Scenario B increases flows South to North by increasing available loads to the North.
- 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)



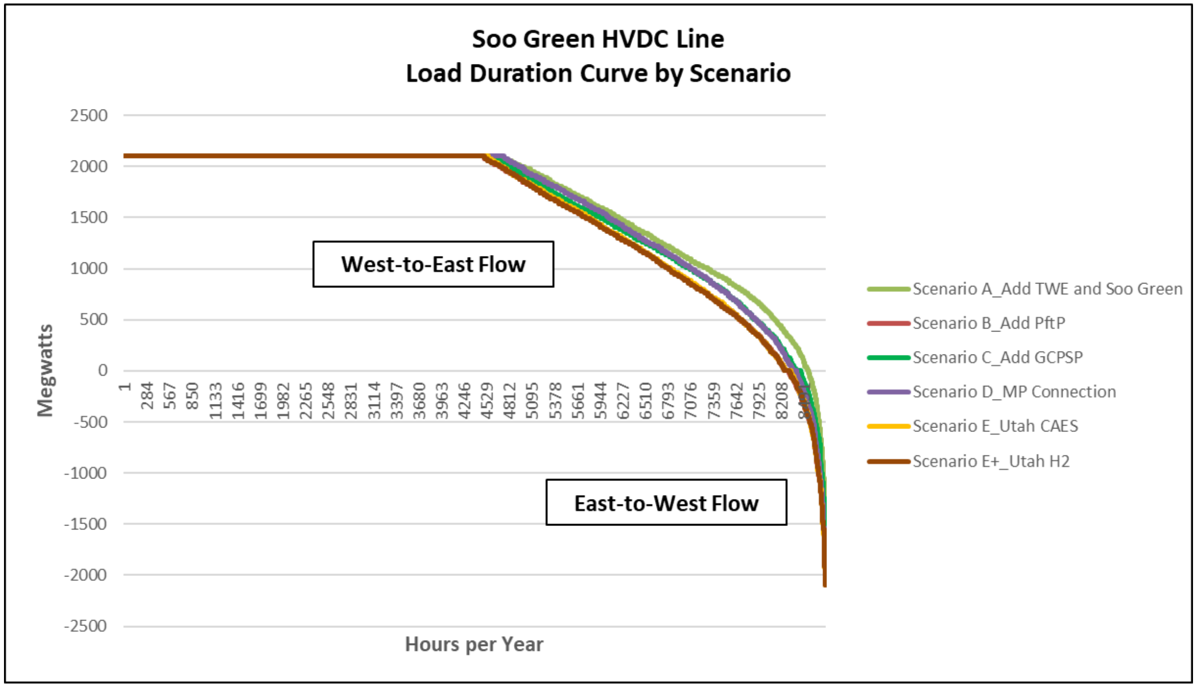
- Scenario A hourly flows for year shown. Positive values are North-to-South flows. Negative values are South-to-North.
- TransWest Express (TWE) flows are primarily North-to-South.

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



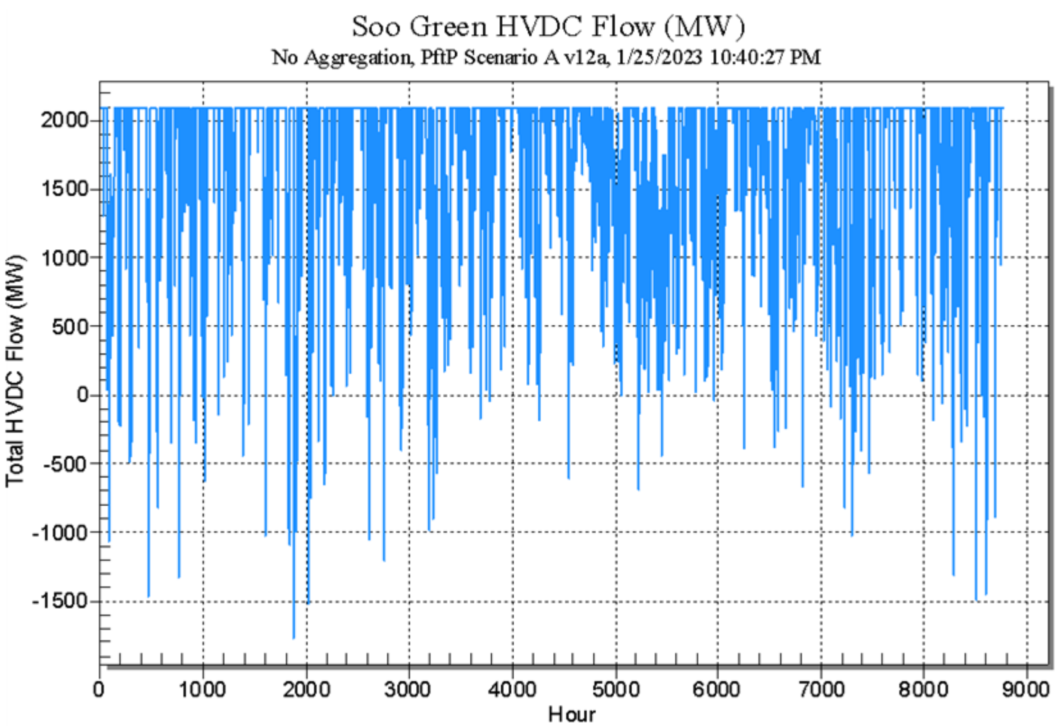
- TransWest Express (TWE) HVAC flows are primarily North-to-South, like the TWE HVDC line.
- PftP increases TWE HVAC flows in both directions.
- MP Connection has no incremental impact on Scenario B (PftP) results.
- Utah CAES (Scenario E) with PftP has most flows North-to-South.

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



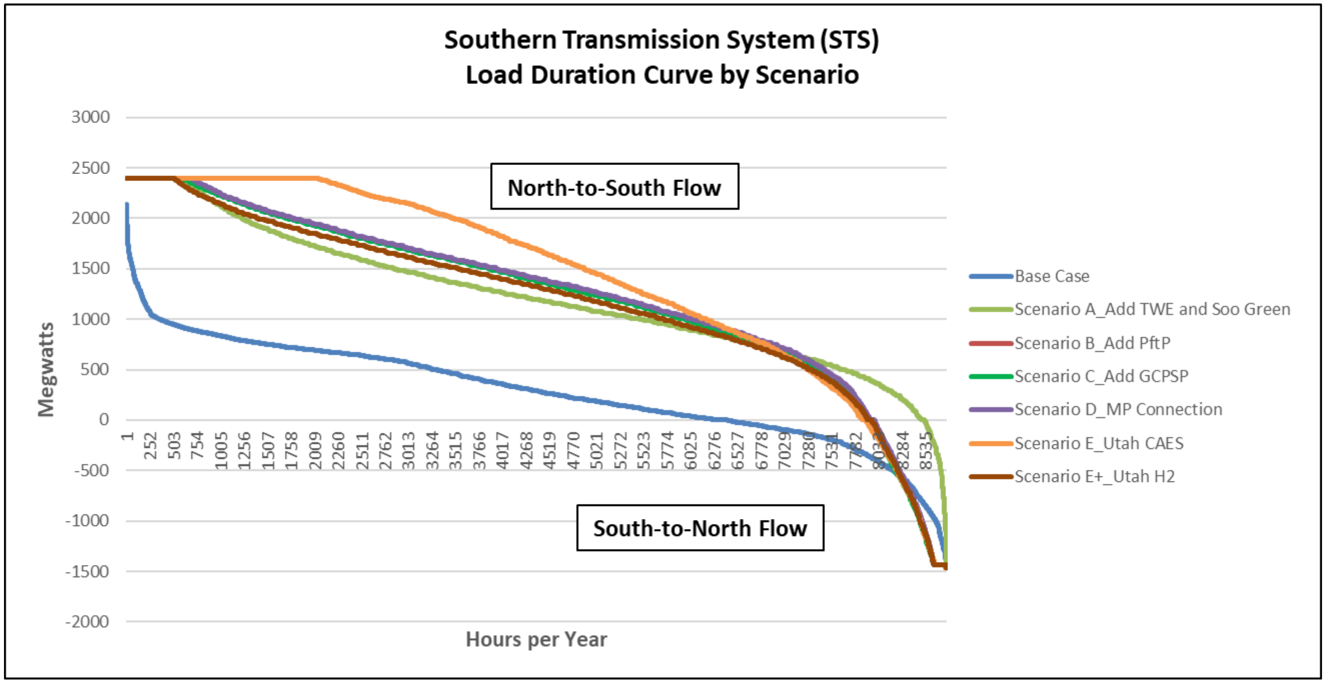
- Soo Green is almost exclusively unidirectional, from West-to-East. Base Case has largest energy flows West-to-East.
- 80% West-to-East capacity factor indicates Soo Green's flow is not just renewable energy.
- Fossil generation output in MISO and SPP increases when Soo Green is added to Base Case.
- 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 East-to-West flows.

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



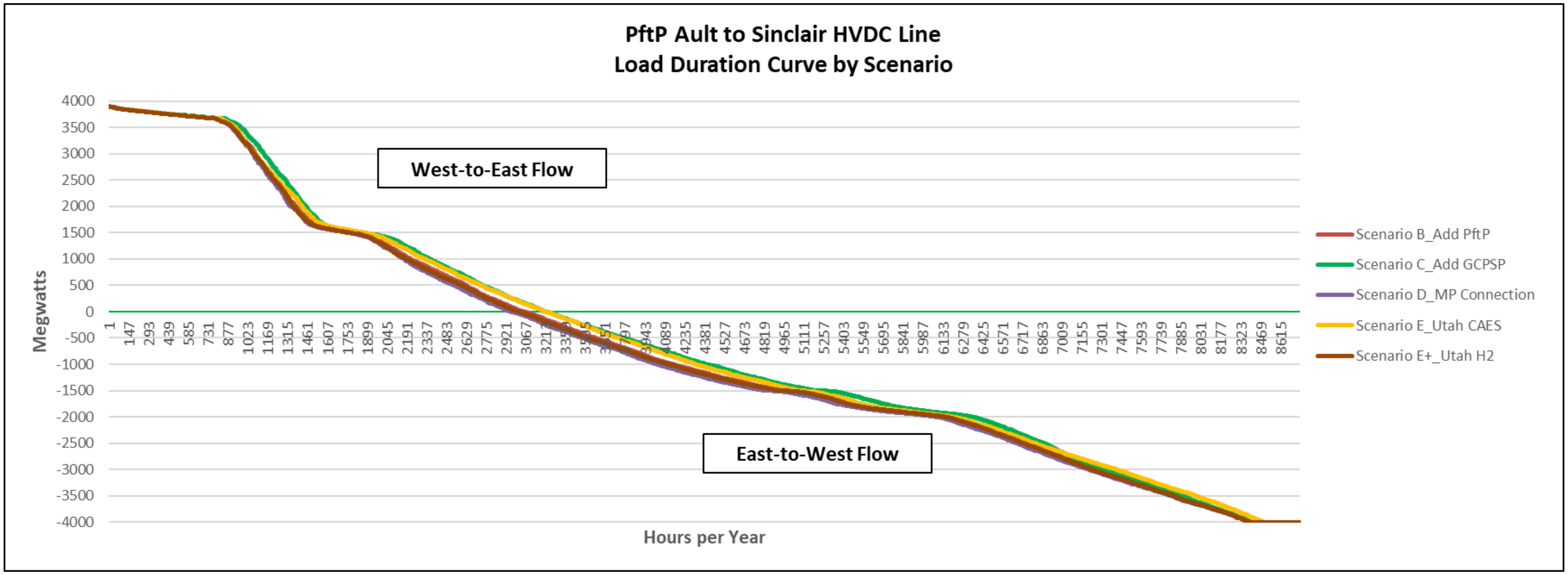
- Scenario A shown. Positive values are West-to-East flows. Negative values are East-to-West.
- Soo Green flows are primarily unidirectional, from West-to-East (i.e., Iowa to Chicago).

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



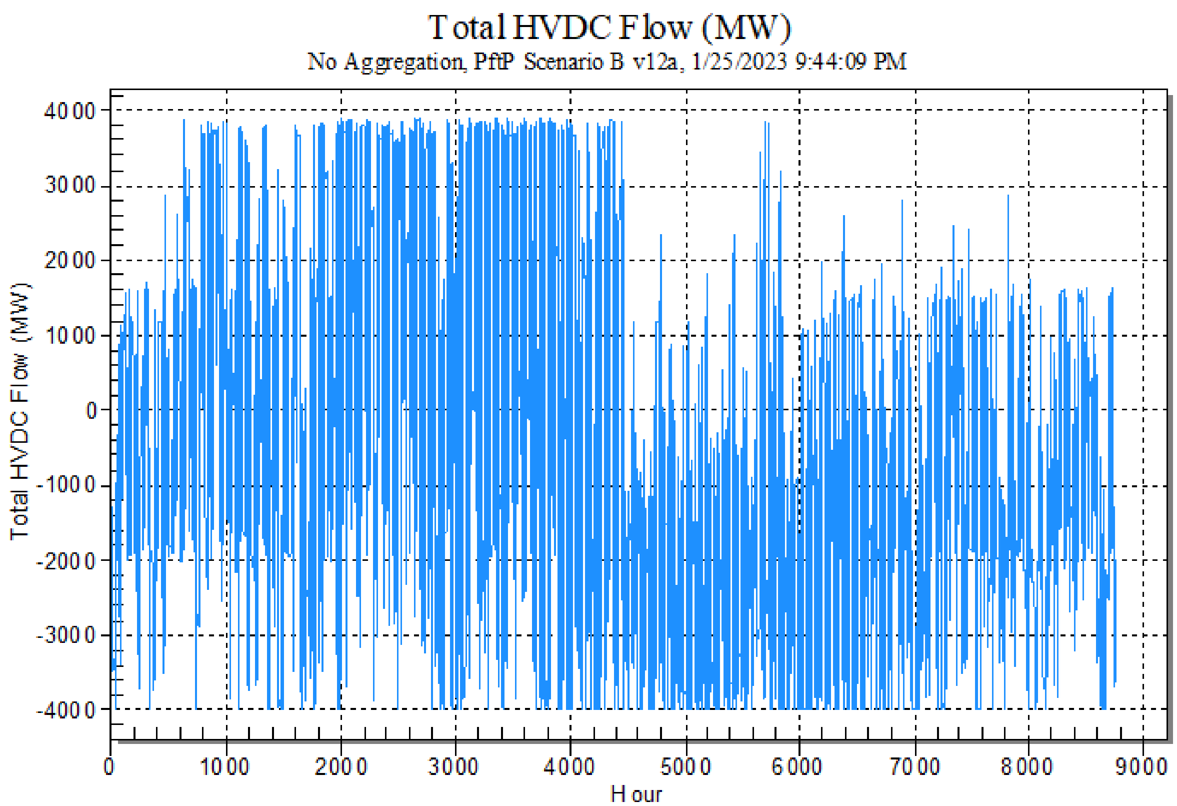
- Flows on the STS are primarily North-to-South, carrying IPP CCTG plant output from Utah to Southern California.
- Scenario A: The TWE HVDC and the 3,300 MW of new wind it enables more than doubles North-to-South energy flows on the STS, and further reduces the already-small South-to-North flows.
- PftP in Scenario B increases N-to-S flows and S-to-N flows, compared to Scenario A.
- 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



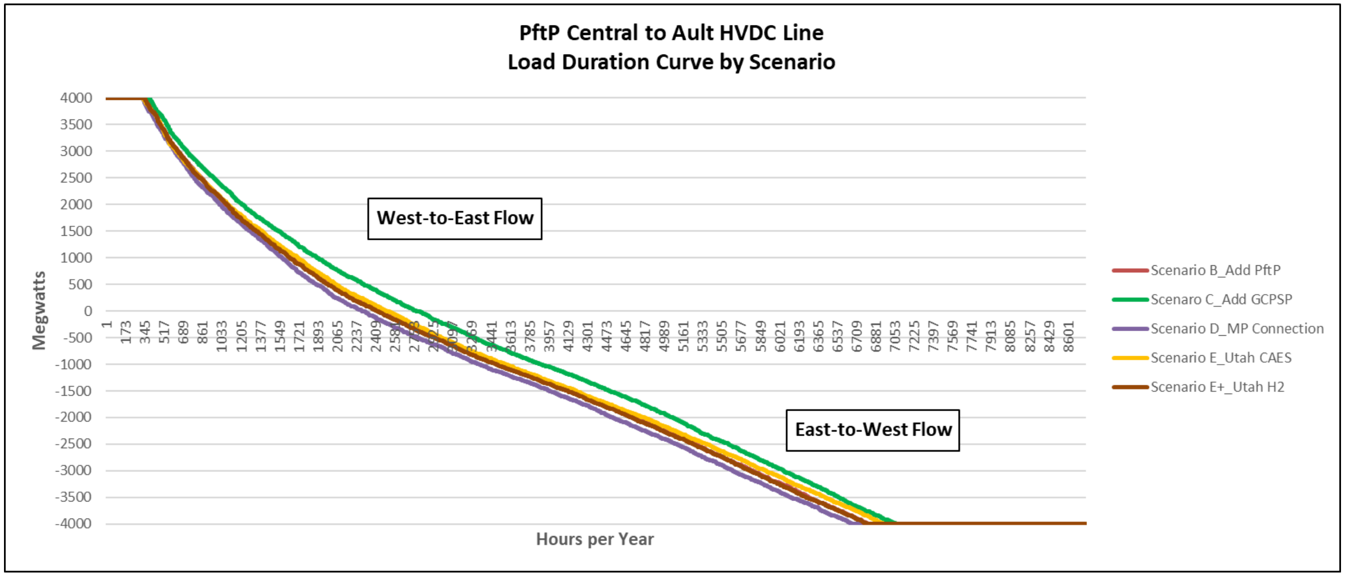
- PftP (Scenario B) flow between the Ault, CO and Sinclair, WY HVDC converters is bi-directional, with more East-to-West flow due to the 3,000 MW of new renewables installed in Central SD/NE.
- Initial planning assumption of 4,000 MW capacity of PftP line with 3,000 MW of new renewables in Scenario B performs well, with 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)



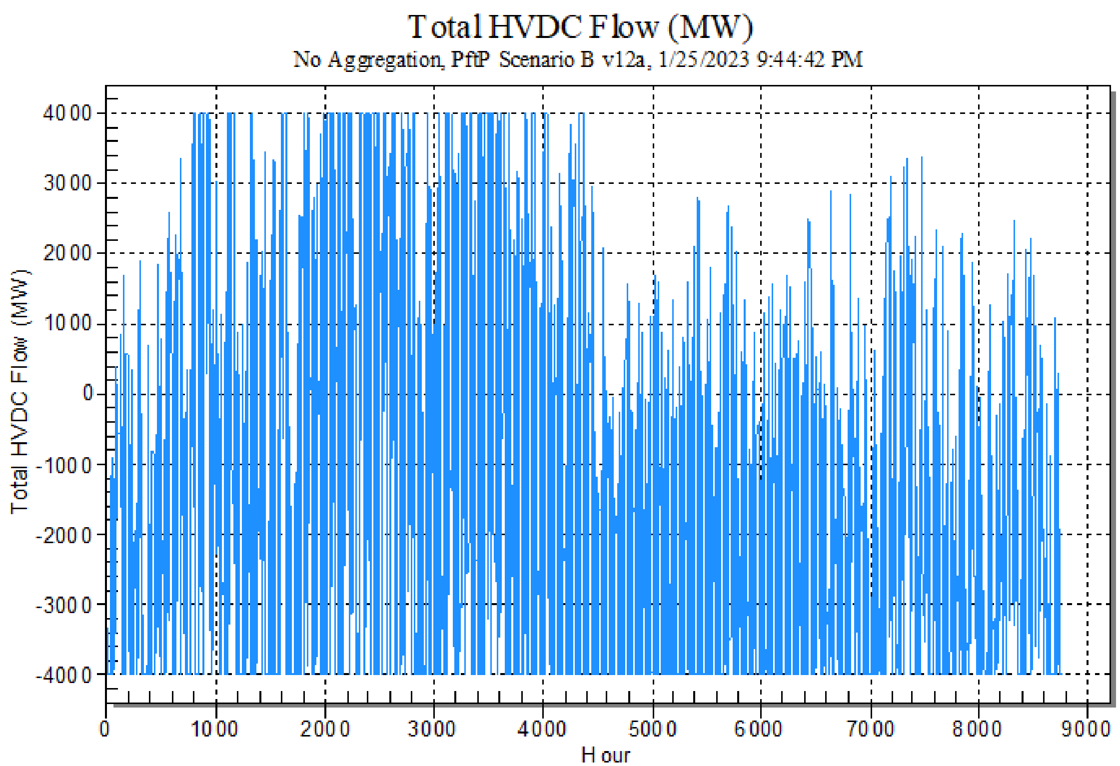
- Scenario B shown. Positive values are West-to-East flows. Negative values are East-to-West.
- PftP line between Sinclair, WY and Ault, CO shows directionality West-to-East in first half of year, then East-to-West in second half.
- Total East-to-West energy flow over the year is larger than West-to-East.

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



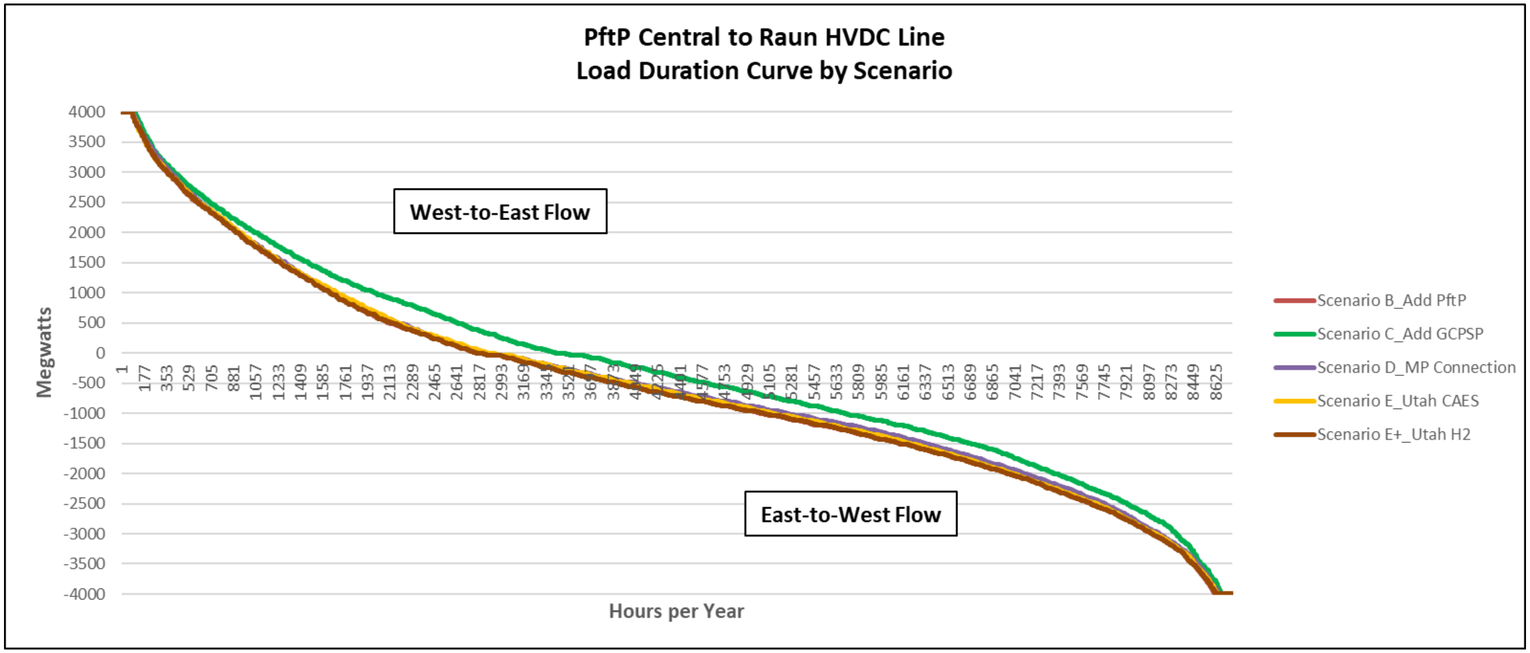
- PftP (Scenario B) flow between the Central SD/NE and Ault, CO HVDC converters is bi-directional, with more East-to-West energy flow, due to the 3,000 MW of new renewables installed in Central SD/NE.
- Initial planning assumption of 4,000 MW capacity of PftP line with 3,000 MW of new renewables in Scenario 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.
  - 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)



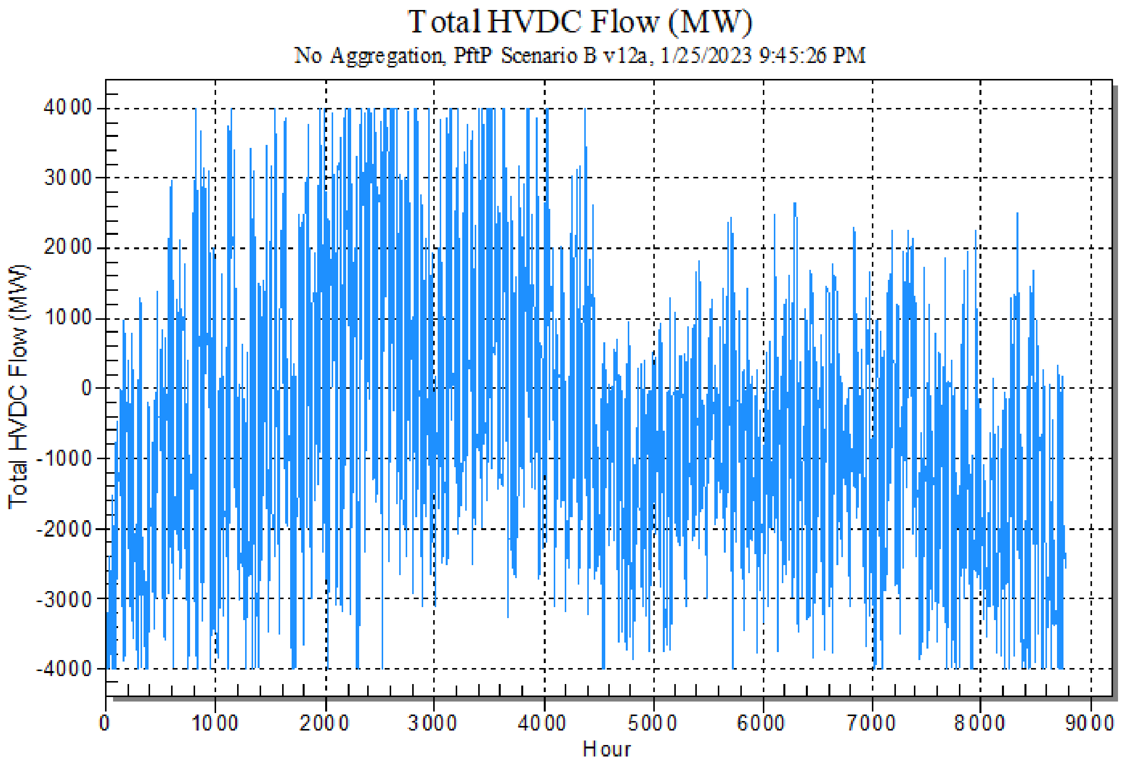
- Scenario B shown. Positive values are West-to-East flows. Negative values are East-to-West.
- PftP line between Ault, CO and Central SD/NE Converter also shows directionality West-to-East in first half of year, then primarily East-to-West in second half.
- Total East-to-West energy flow over the year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

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



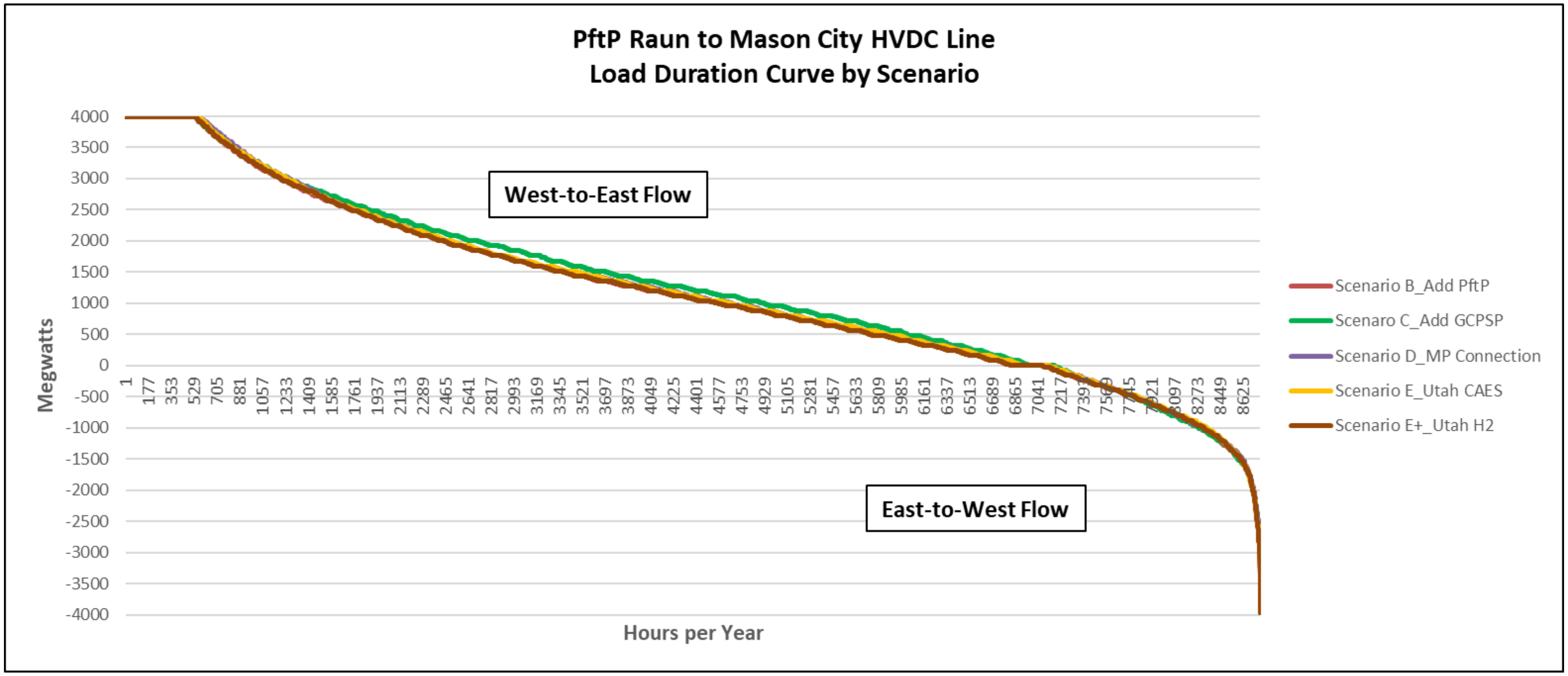
- PftP (Scenario B) flow between the Central SD/NE and Raun, IA HVDC converters is bi-directional.
- Interestingly, although the directional flows are balanced overall, there is more energy flow from Iowa to Central SD/NE, in spite of the 3,000 MW of new renewables installed in Central SD/NE. More energy 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.

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



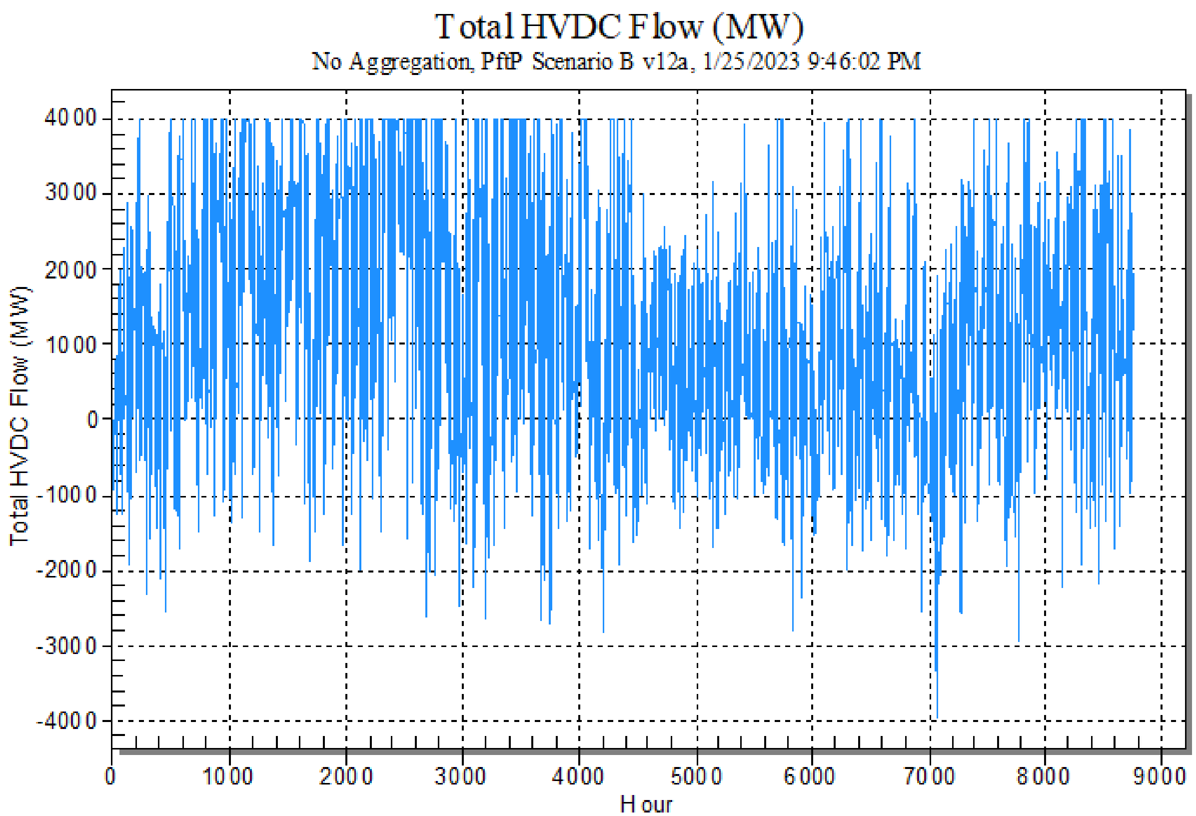
- Scenario B shown. Positive values are West-to-East flows. Negative values are East-to-West.
- PftP line between Central SD/NE Converter and Raun (Sioux City) also shows directionality West-to-East in first half of year, then primarily East-to-West in second half.
- Total East-to-West energy flow over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

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



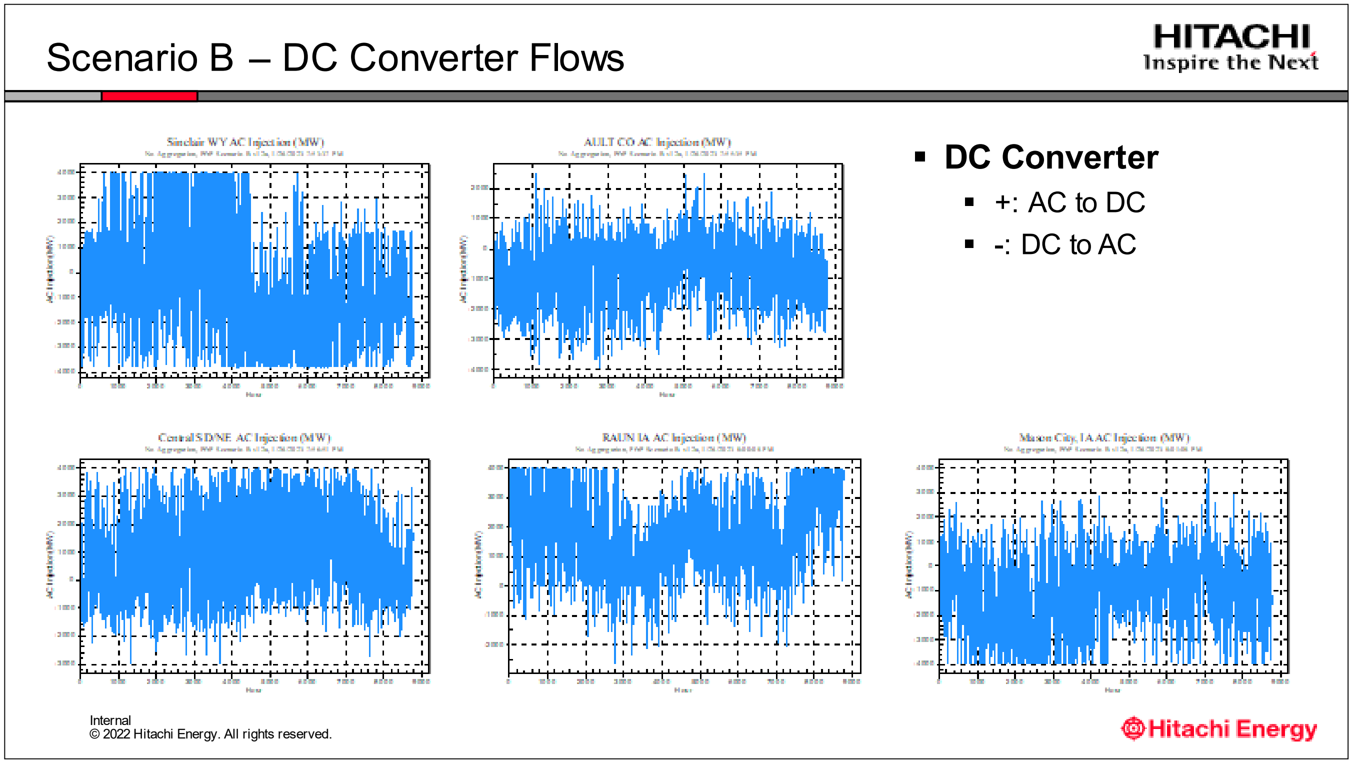
- In contrast to the other PftP line segments where flows are bi-directional, flows between Raun (Sioux City) and Mason City are strongly and almost completely uni-directional West-to-East.
- Raun appears to be a net source of generation in both directions, to the West and to the East.
    - Flows on 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, 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)



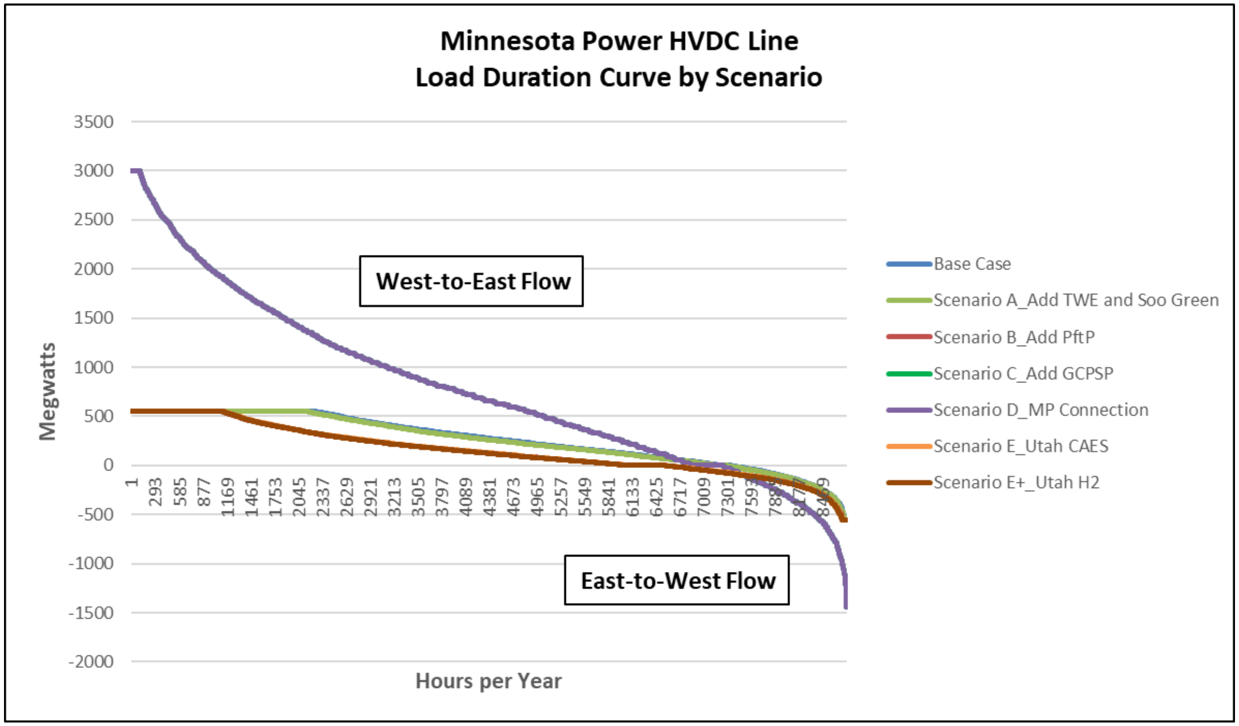
- Scenario B shown. Positive values are West-to-East flows. Negative values are East-to-West.
- Unlike the other PftP line segments, flows on the PftP line between Raun (Sioux City) and Killdeer (Mason City) are primarily unidirectional from West-to-East all year.
- Total West-to-East energy flow over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

Exhibit V-5J. PftP HVDC Converter Flows



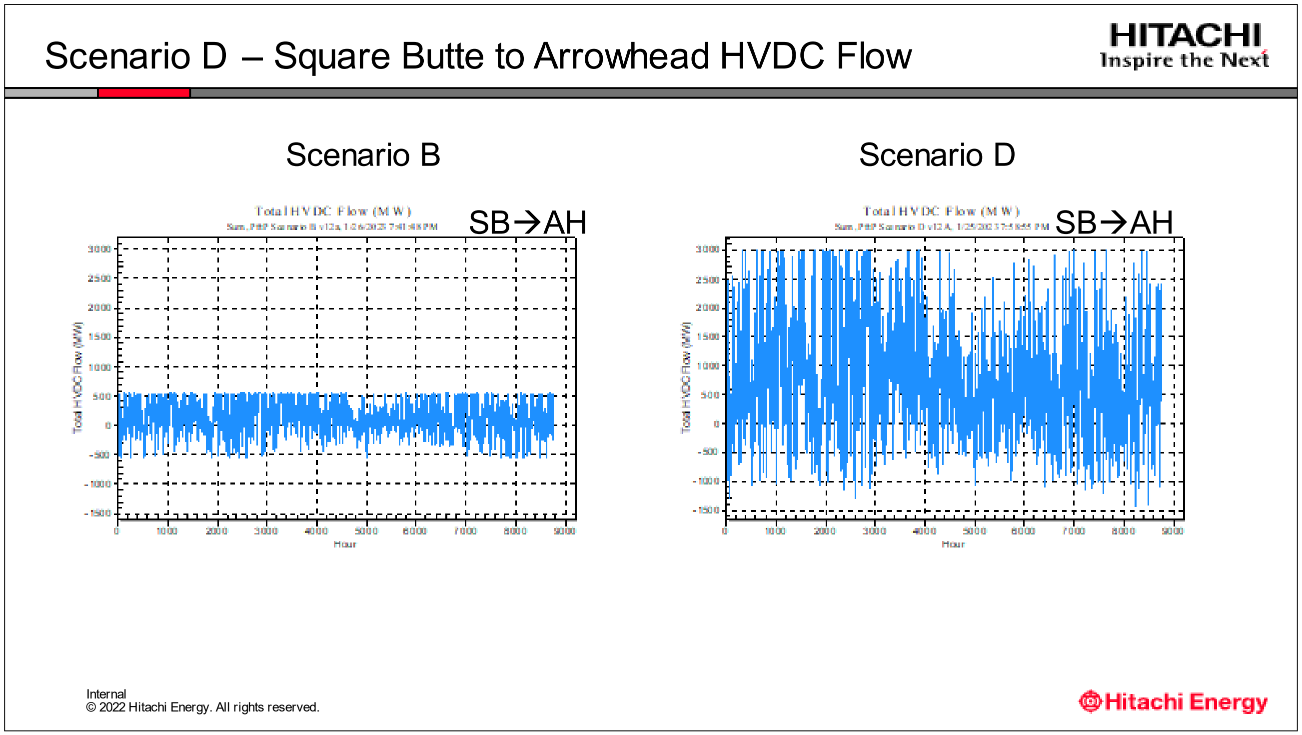
- From Scenario B, flows into and out of the five HVDC converters are shown.
- Ault and Sioux City are primarily injecting energy from the AC system into PftP DC line. Central SD/NE and Sinclair both inject energy into and withdraw energy from PftP. Sinclair is seasonal: AC to DC first half of the year. 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.
  - Basin apparently also benefitting from the development, with some energy from the new renewables going West.

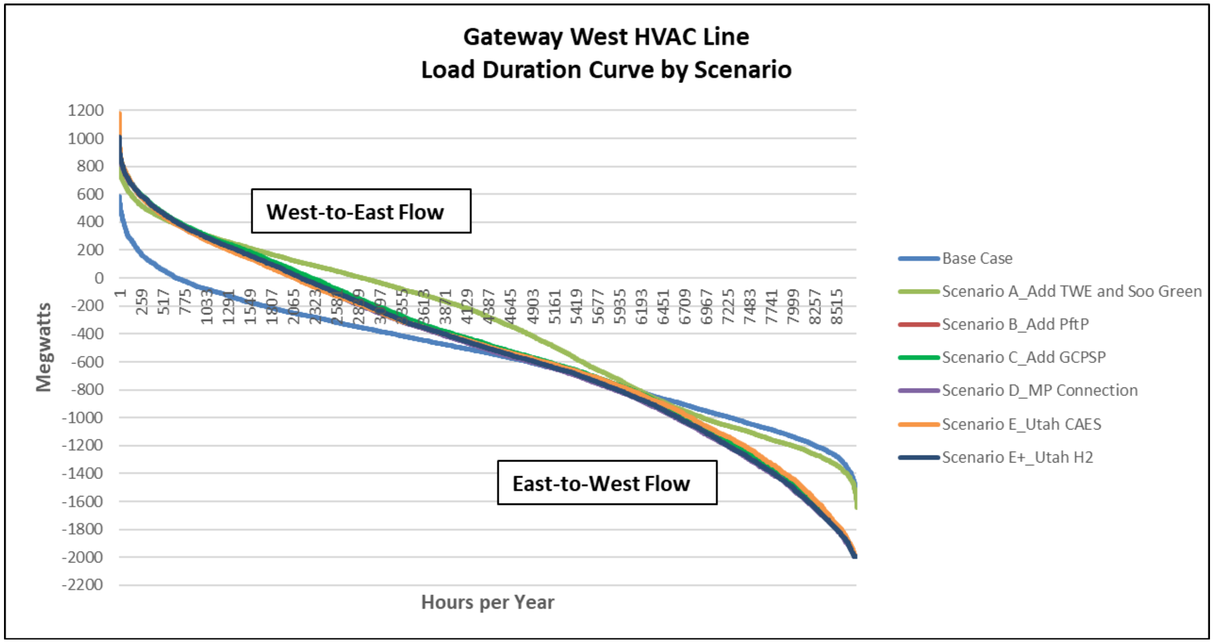
Exhibit V-5L. Peak MW and MWh Loading, MP Connection HVDC (continued)



- Scenarios B and D shown. Positive values are West-to-East. Negative values are East-to-West.
- 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

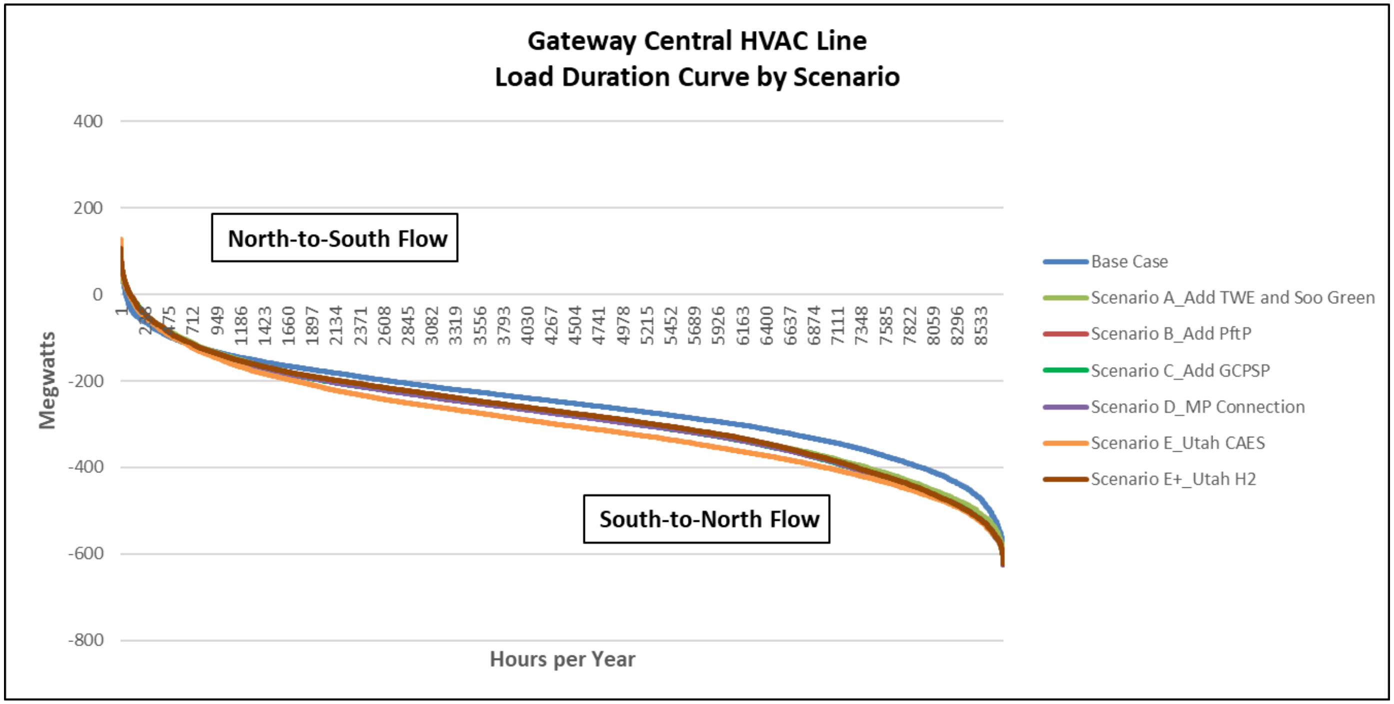
Gateway West



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

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

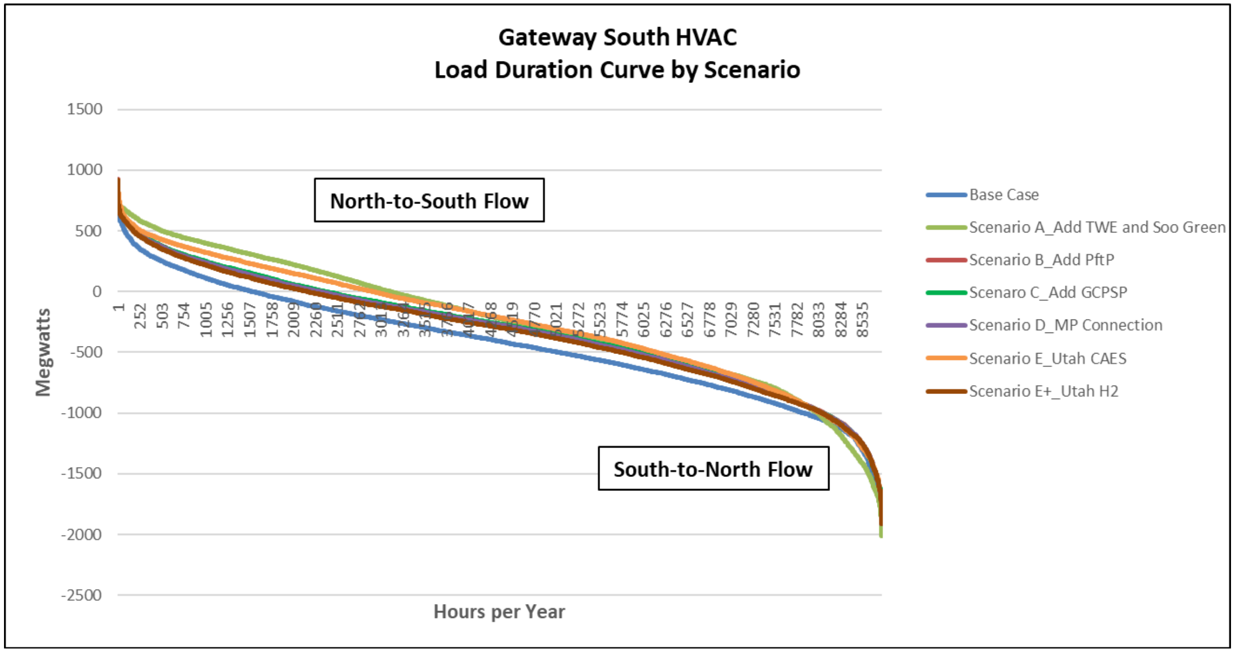
Gateway Central



- 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.

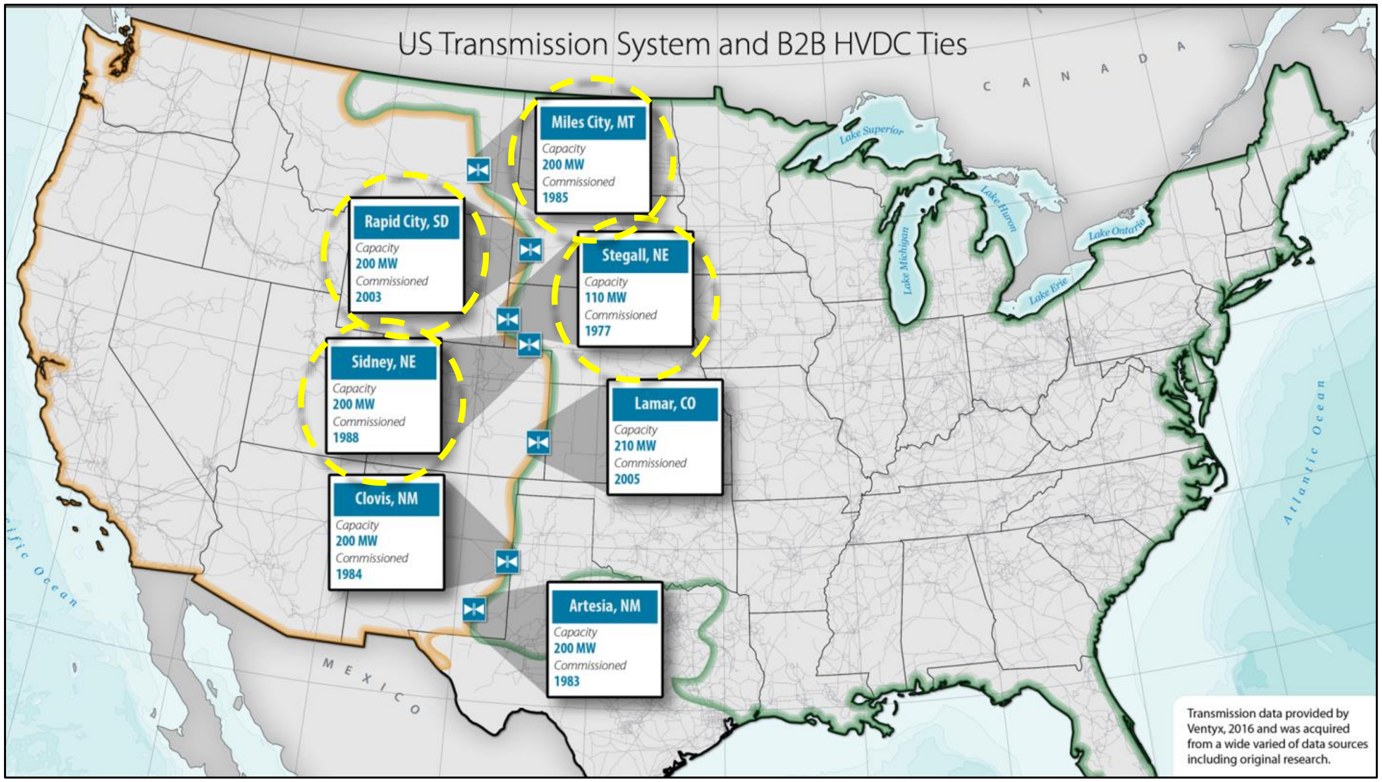
Exhibit V-50. Peak MW and MWh Loading, Gateway South HVAC

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 similar results.

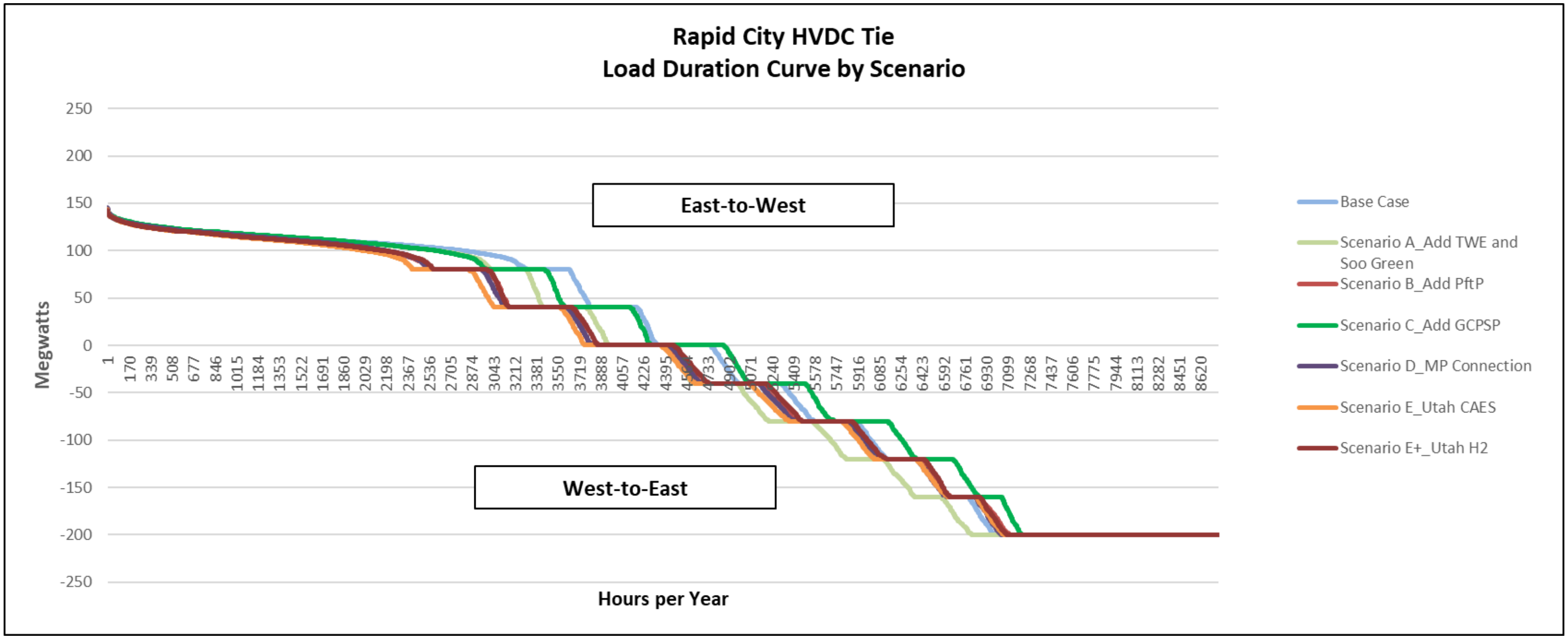
Exhibit V-5P. Locations of The Back-to-Back HVDC Ties



- 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.

Graphic Source: NREL

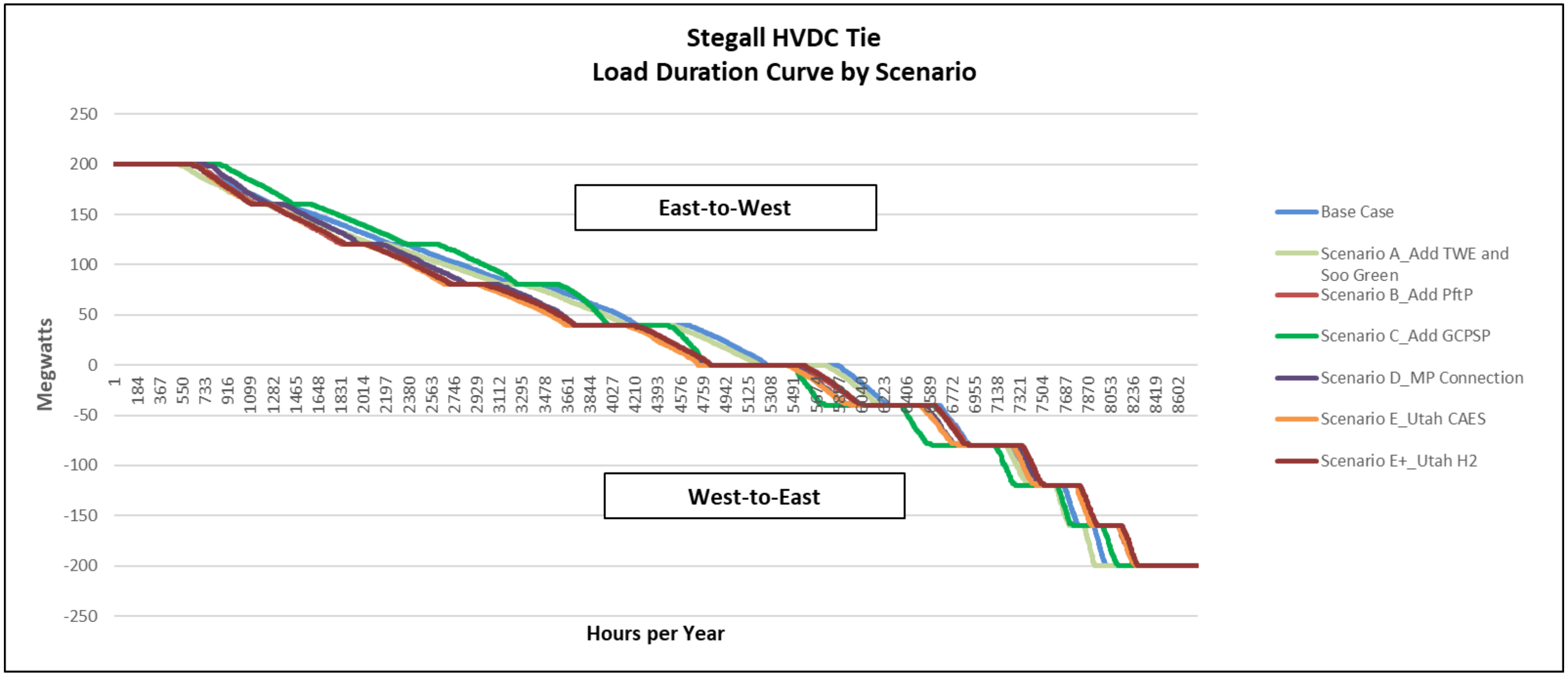
Exhibit V-5Q. Peak MW and MWh Loading, Rapid City HVDC Tie



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

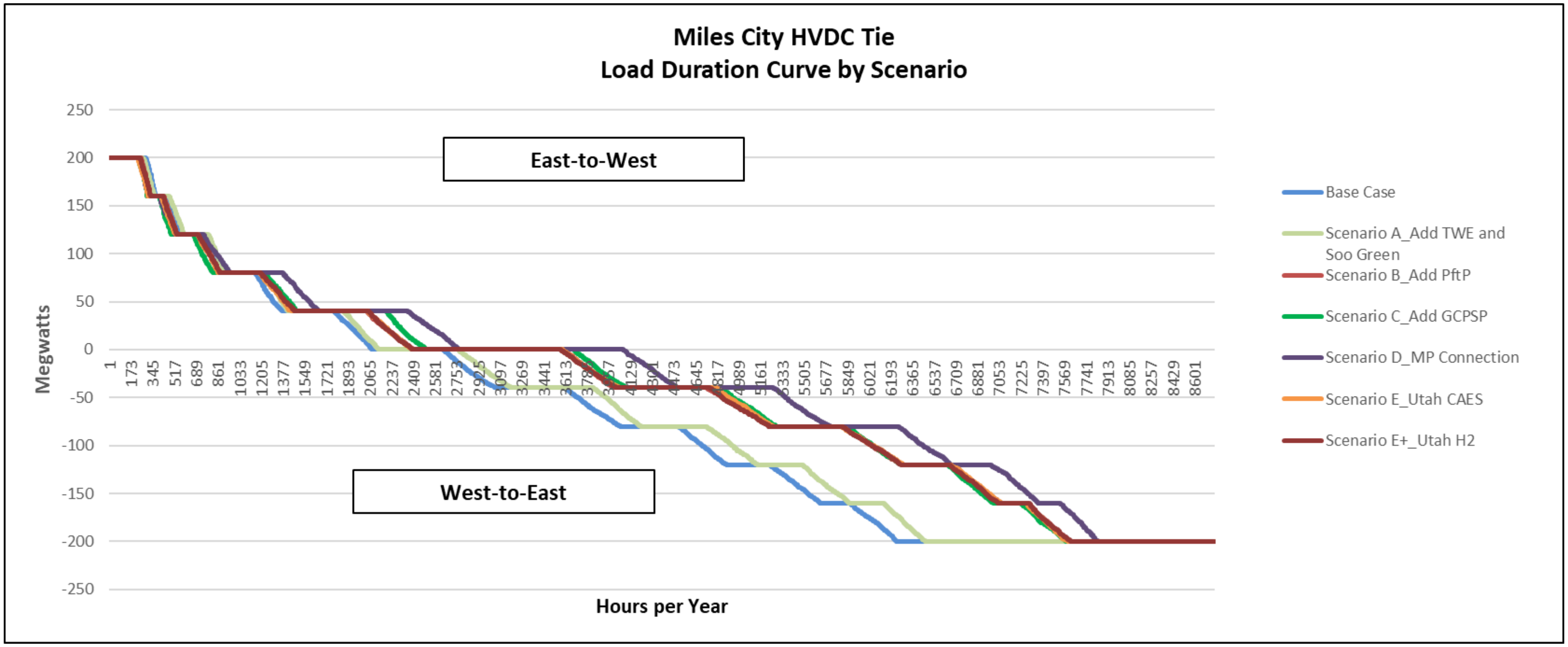
NOTE: The apparent stairstep changes in flows shown for all HVDC ties are a result of simplified, 5-step linear approximation of non-linear transmission losses in the modeling of the relatively small ties. This is not a characteristic of the tie facilities themselves. More granular, 100-step approximations 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



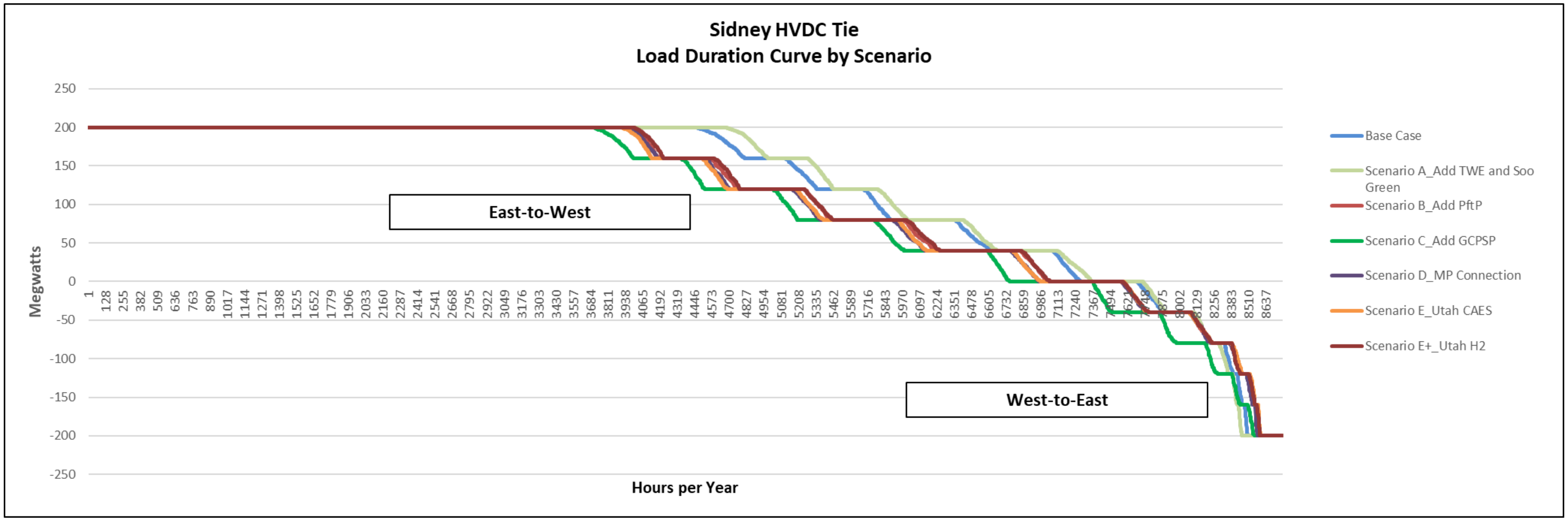
- Similar flows on this tie for all Scenarios.

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.

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



- PftP (Scenario B) reduces East-to-West flows compared to the Base Case.
- 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[1]	Investor-Owned[2]
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.

Exhibit V-6B. Project Capital Costs and Benefits by Scenario

	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	$ -	$ 600	$ 360	$ 500	$ 240	Not applicable
Totals	**$ 8,610**	**$ 3,874**	**$ 13,999**	**Confidential**	**$ 6,988**	**$ 5,126**	**Calculated**
Benefits							
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	Units	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	$200	per kW	2030$
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.
- Shifted WECC wind/solar hourly load shapes to Eastern Time Zone for consistency with MISO MTEP database.
- MISO Tranche 1 transmission projects are added to Base Case per MISO recommendation.
- 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.
- 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.

  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 ($M)			
Capacity (MW)	3,000	TranWest Express website.	
Capital cost ($M)	$ 3,000	TranWest Express website.	
Fixed O&M ($/converter, 2022$)	$ 650,000	30% labor loading	
Wyoming Power Company wind			
Installed capacity (MW)	3,300	TranWest Express website.	
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	$10M per 150 MW of CT capacity.	
Proposed ITC on HVDC and HVAC transmission lines (% of capital cost)	0%	Sensitivity: Try 30% per Heinrich bill.	
Cost escalation rate (%/year)	3%		
Benefit/Cost Analysis ($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	$ 326		
Annual investment-related cost on AC interconnection Tx for TWE enabled renewables	$ 79		
Total Annual fixed costs, TWE affiliated renewables		$ 405	
Total Fixed Costs of TWE line and its renewables			$ 767
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 Perspective			
Assumptions			
TransWest Express HVDC Line capital cost ($M)			
Capacity (MW)	3,000	TranWest Express website.	
Capital cost ($M)	$ 3,000	TranWest Express website.	
Fixed O&M ($/converter, 2022$)	$ 650,000	30% labor loading	
Wyoming Power Company wind			
Installed capacity (MW)	3,300	TranWest Express website.	
Capital cost ($/kW)	$ -		
AC interconnection transmission capital cost ($/kW)	$ -		
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	$10M per 150 MW of CT capacity.	
Proposed ITC on HVDC and HVAC transmission lines (% of capital cost)	0%	Sensitivity: Try 30% per Heinrich bill.	
Cost escalation rate (%/year)	3%		
Benefit/Cost Analysis ($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 e	$ -		
Total Annual fixed costs, TWE affiliated renewables		$ -	
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 its 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 transmission.			**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 ($M)					
Capacity (MW)		3,000	TransWest Express website.		
Capital cost ($M)	$	3,000	TransWest Express website.		
Fixed O&M ($/converter, 2022$)	$	650,000	30% labor loading		
Wyoming Power Company wind					
Installed capacity (MW)		3,300	TransWest Express website.		
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)		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	$10M per 150 MW of CT capacity.		
Proposed ITC on HVDC and HVAC transmission lines (% of capital cost)		0%	Sensitivity: Try 30% per Heinrich bill.		
Cost escalation rate (%/year)		3%			
Benefit/Cost Analysis ($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 Structure.					
Assumptions					
TransWest Express HVDC Line capital cost ($M)					
	Capacity (MW)	3,000	TransWest Express website.		
	Capital cost ($M)	$ 3,000	TransWest Express website.		
	Fixed O&M ($/converter, 2022$)	$ 650,000	30% labor loading		
Wyoming Power Company wind					
	Installed capacity (MW)	3,300	TransWest Express website.		
	Capital cost ($/kW)	$ -			
	AC interconnection transmission capital cost ($/kW)	$ -			
	ELCC capacity value of wind (% of installed capacity)	10%	Current ELCC 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	$10M per 150 MW of CT capacity.		
Proposed ITC on HVDC and HVAC transmission lines (% of capital cost)		0%	Sensitivity: Try 30% per Heinrich bill.		
Cost escalation rate (%/year)		3%			
Benefit/Cost Analysis ($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	$ -			
	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 public power made eligible for credit like done in the IRA for renweables and storage.				

Exhibit V-7D. Scenario A: TransWest, Public Power, RTO Perspective (continued)
With hypothetical capital structure

Scenario A: Add TransWest to the Base Case, Public Power, RTO Perspective, Hypotehtical Capital Structure.					
Assumptions					
TransWest Express HVDC Line capital cost ($M)					
Capacity (MW)		3,000	TransWest Express website.		
Capital cost ($M)	$	3,000	TransWest Express website.		
Fixed O&M ($/converter, 2022$)	$	650,000	30% labor loading		
Wyoming Power Company wind					
Installed capacity (MW)		3,300	TransWest Express website.		
Capital cost ($/kW)	$	-			
AC interconnection transmission capital cost ($/kW)	$	-			
ELCC capacity value of wind (% of installed capacity)		10%	Current ELCC 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)		12.00%			
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	$10M per 150 MW of CT capacity.		
Proposed ITC on HVDC and HVAC transmission lines (% of capital cost)		0%	Sensitivity: Try 30% per Heinrich bill.		
Cost escalation rate (%/year)		3%			
Benefit/Cost Analysis ($M in 2030)					
Transwest Express Project Costs					
Annual investment-related Fixed costs on TransWest Express	$	360			
Fixed O&M, TransWest Express DC	$	1.6			
Total Annual fixed costs, TWE line			$ 362		
Annual investment-related fixed costs on TWE affiliated renewables	$	-			
Annual investment-related cost on AC interconnection Tx for TWE affiliated renewa	$	-			
Total Annual fixed costs, TWE affiliated renewables			$ -		
Total Fixed Costs of TWE line and its renewables				$ 362	
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				**2.06**	
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 storage.					

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 ($M)			
Capacity (MW)	2,100	Soo Green website.	
Capital cost ($M)	$ 2,500	Soo Green website.	
Fixed O&M ($/converter, 2022$)	$ 650,000	30% labor loading	
Soo Green AC interconnections			
Capital Cost ($M in 2030$)	$ 1,374	CDS Study Team 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 Heinrich 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	$ -		
Total Annual fixed costs, TWE affiliated renewables		$ -	
Total Fixed Costs of Soo Green line and its renewables			$ 387
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			**0.19**
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 ($M)				
Capacity (MW)	2,100	Soo Green website.		
Capital cost ($M)	$ 2,500	Soo Green website.		
Fixed O&M ($/converter, 2022$)	$ 650,000	30% labor loading		
Soo Green AC interconnections				
Capital Cost ($M)	$ 1,374	CDS Study Team estimate.		
Enabled renewables	-			
Levelized 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: Try 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	$ -			
Total Annual fixed costs, TWE enabled renewables		$ -		
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

Scenario B: Add PftP line to Scenario A (with Soo Green at 2100 MW), Investor-owned finacials, *Total Resource Perspective*			
Assumptions (All numbers in 2030$ unless noted)			
PftP HVDC Line capital cost ($M)			
Capacity (MW)	4,000	CDS Study Team estimate	
Capital cost ($M)	$ 6,814	CDS Study Team estimate.	
Capital cost, converters only ($M)	$ 3,167	CDS Study Team estimate.	
Capital cost, DC overhead lines only ($M)	$ 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 ($M)	$ 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)	$ 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)			
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	$10M per 150 MW of CT capacity.	
Proposed ITC on HVDC and HVAC transmission lines (% of capital cost)	0%	Sensitivity: Try 30% per Heinrich bill.	
Cost escalation rate	3%		
Benetif/Cost Analysis ($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-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	
Total Fixed Costs of PftP line and its renewables			$ 1,418
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 renewables		$ (816)	
Net Cost (Benefit) of PftP and its generic renewables			**$ (899)**
Net Benefit/Cost Ratio			**0.63**
Benefit/Cost Ratio 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-owned finacials,			*RTO Perspective*	
Assumptions (All numbers in 2030$ unless noted)				
PftP HVDC Line capital cost ($M)				
Capacity (MW)		4,000	CDS Study Team estimate	
Capital cost ($M)	$	6,814	CDS Study Team estimate.	
Capital cost, converters only ($M)	$	3,167	CDS Study Team estimate.	
Capital cost, DC overhead lines only ($M)	$	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 ($M)	$	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 ELCC of 15% and 50% reduced to	
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)				
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	$10M per 150 MW of CT capacity.	
Proposed ITC on HVDC and HVAC transmission lines (% of capital cost)		0%	Sensitivity: Try 30% per Heinrich bill.	
Cost escalation rate		3%		
Benetif/Cost Analysis ($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-enabled generic renewables	$	-		
Annual investment-related cost on AC interconnection Tx for PftP-enabled r	$	-		
Total Annual fixed costs, PftP generic renewables			$ -	
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 renewables			$ (816)	
Net Cost (Benefit) of PftP and its generic renewables				**$ (899)**
Net Benefit/Cost Ratio				**0.84**
Benefit/Cost Ratio with proposed 30% ITC for HVDC and HVAC transmisison				**1.20**

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

Scenario B: Add PftP line to Scenario A (with Soo Green at 2100 MW), Public Power Financials, Total Resource Perspective			
Assumptions (All numbers in 2030$ unless noted)			
PftP HVDC Line capital cost ($M)			
Capacity (MW)	4,000	CDS Study Team estimate	
Capital cost ($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	
Fixed O&M ($/converter, 2022$)	$ 650,000	30% labor loading	
PftP AC Interconnection lines added for Scenario B			
Capital cost ($M)	$ 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)	$ 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% located on Native American land.	
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	$10M per 150 MW of CT capacity.	
Proposed ITC on HVDC and HVAC transmission lines (% of capital cost)	0%	Sensitivity: Try 30% per proposed ITC bill (S.1016, Henrich)	
Cost escalation rate (%/year)	3%		
Benefit/Cost Analysis ($M in 2030)			
Power from the Prairie Project Costs			
Annual investment-related fixed costs of PftP DC line	$ 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*	$ 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			$ 760
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			**$ (873)**
Net Benefit/Cost Ratio			**1.15**
Net Benefit/Cost Ratio if proposed 30% ITC on transmission*			**1.44**
*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
Without hypothetical capital structure

Scenario B: Add PftP line to Scenario A (with Soo Green at 2100 MW), Public Power Financials, RTO Perspective, No Hypothetical Capital Structure			
Assumptions (All numbers in 2030$ unless noted)			
PftP HVDC Line capital cost ($M)			
Capacity (MW)	4,000	CDS Study Team estimate	
Capital cost ($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	
Fixed O&M ($/converter, 2022$)	$ 650,000	30% labor loading	
PftP AC Interconnection lines added for Scenario B			
Capital cost ($M)	$ 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 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%	IRA, 15% discount on ITC due to tax-exampt financing, 50%	
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	$10M per 150 MW of CT capacity.	
Proposed ITC on HVDC and HVAC transmission lines (% of capital cost)	0%	Sensitivity: Try 30% per proposed ITC bill (S.1016, Henrich)	
Cost escalation rate (%/year)	3%		
Benefit/Cost Analysis ($M in 2030)			
Power from the Prairie Project Costs			
Annual investment-related fixed costs of PftP DC line	$ 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 renewat	$ -		
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 renewables		$ (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)
With hypothetical capital structure

Scenario B: Add PftP line to Scenario A (with Soo Green at 2100 MW), Public Power Financials, RTO Perspective, Hypothetical Capital Structure			
Assumptions (All numbers in 2030$ unless noted)			
PftP HVDC Line capital cost ($M)			
Capacity (MW)	4,000	CDS Study Team estimate	
Capital cost ($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	
Fixed O&M ($/converter, 2022$)	$ 650,000	30% labor loading	
PftP AC Interconnection lines added for Scenario B			
Capital cost ($M)	$ 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 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%	IRA, 15% discount 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 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			**$ (873)**
Net Benefit/Cost Ratio			**0.82**
Net Benefit/Cost Ratio if proposed 30% ITC on transmission*			**1.16**
*If public power made eligible for credit like done in the IRA for renweables and storage.			

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-7O. Scenario D: MP Connection, Investor, Total Resource Perspective

Scenario D: Add MP Connection to PftP, Investor Financing, ***Total Resource Perspective***				
Assumptions				
MP ND to Duluth HVDC Line capital cost ($M)				
Capacity (MW)	3,000	MP assumption		
Total Capital cost ($M)	$ 2,074	CDS Study Team estimate (2022$)		
Capital cost, converters only ($M)	$ 1,080	CDS Study Team estimate (2022$)		
Capital cost, DC overhead lines only ($M)	$ 994	CDS Study Team estimate (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 assumption		
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 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)	30%	Inflation Reduction Act		
MP Connection AC Interconnection lines added for Scenario D				
Capital cost (2022$M)	$ 525	CDS Study Team estimate		
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	$10M per 150 MW of CT capacity.		
Proposed ITC on HVDC and HVAC transmission lines (% of capital cost)	0%	Sensitivity: Try 30% per Heinrich bill.		
Cost escalation rate (%/year)	3%			
Benefit/Cost Analysis ($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	$ 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		$ (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				
Assumptions				
MP ND to Duluth HVDC Line capital cost ($M)				
Capacity (MW)	3,000	MP assumption		
Total Capital cost ($M)	$ 2,074	CDS Study Team estimate (2022$)		
Capital cost, converters only ($M)	$ 1,080	CDS Study Team estimate (2022$)		
Capital cost, DC overhead lines only ($M)	$ 994	CDS Study Team estimate (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 assumption		
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 ELCC of 15% and 50% reduced to		
Inflation Reduction Act Investment Tax credit (% of capital cost)	30%	Inflation Reduction Act		
MP Connection AC Interconnection lines added for Scenario D				
Capital cost (2022$M)	$ 525	CDS Study Team estimate		
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	$10M per 150 MW of CT capacity.		
Proposed ITC on HVDC and HVAC transmission lines (% of capital cost)	0%	Sensitivity: Try 30% per Heinrich bill.		
Cost escalation rate (%/year)	3%			
Benefit/Cost Analysis ($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 ($M)			
Capacity (MW)	3,000	MP assumption	
Total Capital cost ($M)	$ 2,074	CDS Study Team estimate (2022$)	
Capital cost, converters only ($M)	$ 1,080	CDS Study Team estimate (2022$)	
Capital cost, DC overhead lines only ($M)	$ 994	CDS Study Team estimate (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 assumption	
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 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)	30%	Inflation Reduction Act	
MP Connection AC Interconnection lines added for Scenario D			
Capital cost (2020$M)	$ 525	CDS Study Team 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	$10M per 150 MW of CT capacity.	
Proposed ITC on HVDC and HVAC transmission lines (% of capital cost)	0%	Sensitivity: Try 30% per Heinrich bill.	
Cost escalation rate (%/year)	3%		
Benefit/Cost Analysis ($M in 2030)			
Transwest Express Project Costs			
Annual investment-related Fixed costs on 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 Hypothetical Tx Capital Structure			
Assumptions			
MP ND to Duluth HVDC Line capital cost ($M)			
Capacity (MW)	3,000	MP assumption	
Total Capital cost ($M)	$ 2,074	CDS Study Team estimate (2022$)	
Capital cost, converters only ($M)	$ 1,080	CDS Study Team estimate (2022$)	
Capital cost, DC overhead lines only ($M)	$ 994	CDS Study Team estimate (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 assumption	
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 ELCC of 15%	
Inflation Reduction Act Investment Tax credit (% of capital cost)	30%	Inflation Reduction Act	
MP Connection AC Interconnection lines added for Scenario D			
Capital cost (2020$M)	$ 525	CDS Study Team 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	$10M per 150 MW of CT capacity.	
Proposed ITC on HVDC and HVAC transmission lines (% of capital cost)	0%	Sensitivity: Try 30% per Heinrich bill.	
Cost escalation rate (%/year)	3%		
Benefit/Cost Analysis ($M in 2030)			
Transwest Express Project Costs			
Annual investment-related Fixed costs on 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	$ -		
Annual investment-related cost on AC interconnection Tx for MP enabled renewable	$ -		
Total Annual fixed costs, MP enabled renewables		$ -	
Total Fixed Costs of MP Connection and its renewables			$ 161
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			**2.24**
Net Benefit/Cost Ratio if 30% ITC on transmission per Heinrich bill.*			**3.19**
*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 (continued)

With hypothetical capital structure

Scenario D: Add MP Connection to PftP, Public financing, RTO Perspective, Hypothetical Tx Capital Structure				
Assumptions				
MP ND to Duluth HVDC Line capital cost ($M)				
Capacity (MW)	3,000	MP assumption		
Total Capital cost ($M)	$ 2,074	CDS Study Team estimate (2022$)		
Capital cost, converters only ($M)	$ 1,080	CDS Study Team estimate (2022$)		
Capital cost, DC overhead lines only ($M)	$ 994	CDS Study Team estimate (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 assumption		
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 ELCC of 15%		
Inflation Reduction Act Investment Tax credit (% of capital cost)	30%	Inflation Reduction Act		
MP Connection AC Interconnection lines added for Scenario D				
Capital cost (2020$M)	$ 525	CDS Study Team estimate		
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	$10M per 150 MW of CT capacity.		
Proposed ITC on HVDC and HVAC transmission lines (% of capital cost)	0%	Sensitivity: Try 30% per Heinrich bill.		
Cost escalation rate (%/year)	3%			
Benefit/Cost Analysis ($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 ($M)				
Capacity (MW)	1,200			
Capital cost ($/kW in 2022$, for 48 hours duration)	$ 2,030			SCPPA RFP for CAES projects.
GCPSP Fixed O&M cost ($/kW-year in 2022$)	$ 62			SCPPA RFP for CAES projects.
PftP AC Interconnection lines needed for GCPSP				
Capital cost ($M)	$ -			Minimal tx needed.
Generic new renewables added with GCPSP				
Installed capacity (MW)	1,200			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)	$ 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
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			$10M per 150 MW of CT capacity.
IRA ITC on pumped hydro storage (% of capital cost)	0%			Sensitivity: Does CAES qualify for IRA 30% ITC on storage?
Cost escalation rate (%/year)	3%			
Benefit/Cost Analysis ($M in 2030)				
Gregory County Pumped Storage Project (GCPSP) Costs, with PftP in place				
Annual investment-related fixed costs of Utah CAES	$ 290			
GCPSP Fixed O&M	$ 94			
Annual investment-related fixed costs on Utah CAES AC interconnection lines	$ -			No tx necessary.
Total Annual fixed costs, Utah CAES and AC transmission lines		$ 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, *RTO Perspective*				
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)	$ 2,030			SCPPA RFP for CAES projects.
GCPSP Fixed O&M cost ($/kW-year in 2022$)	$ 62			SCPPA RFP for CAES projects.
PftP AC Interconnection lines needed for GCPSP				
Capital cost ($M)	$ -			Minimal tx needed.
Generic new renewables added with GCPSP				
Installed capacity (MW)	1,200			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 capacity)	0.24			Current ELCC 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	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			$10M per 150 MW of CT capacity.
IRA ITC on pumped hydro storage (% of capital cost)	0%			Sensitivity: Does CAES qualify for IRA 30% ITC on storage?
Cost escalation rate (%/year)	3%			
Benefit/Cost Analysis ($M in 2030)				
Gregory County Pumped Storage Project (GCPSP) Costs, with PftP in place				
Annual investment-related fixed costs of Utah CAES	$ 290			
GCPSP Fixed O&M	$ 94			
Annual investment-related fixed costs on Utah CAES AC interconnection lines	$ -			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	$ -			
Total Annual fixed costs, PftP generic renewables		$ -		
Total Fixed Costs of PftP line and its renewables			**$ 384**	
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			**0.74**	
Net Benefit/Cost Ratio if Utah CAES eligible for 30% ITC for storage in the IRA			**0.96**	

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 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 tx needed.		
Generic new renewables added with Utah CAES				
Installed capacity (MW)	1,200	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)	$ 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		
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	$10M per 150 MW of CT capacity.		
IRA ITC on pumped hydro storage (% of capital cost)	**0%**	Sensitivity: Does CAES qualify for IRA 30% ITC on storage?		
Cost escalation rate (%/year)	3%			
Benefit/Cost Analysis ($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	$ 94			
Annual investment-related fixed costs on Utah CAES AC interconnection lines	$ -		No tx necessary.	
Total Annual fixed costs, Utah 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 IRA offers renewables 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, *RTO Perspective, No Hypothetical Tx Cap Structure*				
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 tx needed.		
Generic new renewables added with Utah CAES				
Installed capacity (MW)	1,200	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 capacity)	0.24	Current ELCC 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)	$ 900			
Storage for biofuels for proxy CT (2022 $/kW)	$ 67	$10M per 150 MW of CT capacity.		
IRA ITC on pumped hydro storage (% of capital cost)	**0%**	Sensitivity: Does CAES qualify for IRA 30% ITC on storage?		
Cost escalation rate (%/year)	3%			
Benefit/Cost Analysis ($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	$ 94			
Annual investment-related fixed costs on Utah CAES AC interconnection lines	$ -		No tx necessary.	
Total Annual fixed costs, Utah CAES and AC transmission lines		$ 295		
Annual investment-related fixed costs on Utah CAES generic renewables	$ -			
Annual investment-related cost on AC interconnection Tx for CAES enabled renewable	$ -			
Total Annual fixed costs, PftP generic renewables		$ -		
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*			**1.08**	
*Assumes public power is eligible for credit benefit as IRA offers renewables and storage.				

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 Structure*			
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 tx needed.	
Generic new renewables added with Utah CAES			
Installed capacity (MW)	1,200	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 capacity)	0.24	Current ELCC 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	$10M per 150 MW of CT capacity.	
IRA ITC on pumped hydro storage (% of capital cost)	**0%**	Sensitivity: Does CAES qualify for IRA 30% ITC on storage?	
Cost escalation rate (%/year)	3%		
Benefit/Cost Analysis ($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	$ 94		
Annual investment-related fixed costs on Utah CAES AC interconnection lines	$ -		No tx necessary.
Total Annual fixed costs, Utah CAES and AC transmission lines		$ 295	
Annual investment-related fixed costs on Utah CAES generic renewables	$ -		
Annual investment-related cost on AC interconnection Tx for CAES enabled renewables	$ -		
Total Annual fixed costs, PftP generic renewables		$ -	
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*			**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

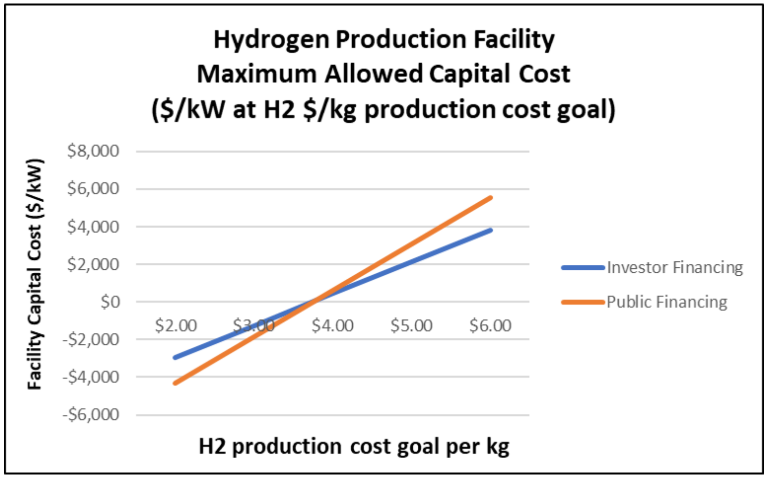
Scenario E+: Add 210 Hydrogen Electrolyzer at Delta, Utah, Investor Financing			
Assumptions			
Utah H2 Electrolyzer at Delta, Utah			
Capacity (MW)	210		
Electrolyzer capacity factor (%)	77.3%	Load pattern input to Gridview modeling.	
Total Capital Cost Electrolyzer	$ 193,200,000	Based on Lazard Study 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 $25/1000 gallo	
Inflation Reduction Act Production Tax Credit for H2 Production ($/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%		
Generation	9.40%		
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%		
Benefit/Cost Analysis ($M in 2030)			
Utah H2 Benefits			
Annual H2 revenue at $/kg goal assumed.	$ 134		
Total Benefits		$ 134.30	
Utah H2 Operating Costs ($M)			
Stack depreciation as this is a consumable	$ 8.2		
Fixed O&M	$ 2.9		
Variable O&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 ($M)			**$ 8.53**
Maximum Allowed Capital Cost of Utah 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 $25/1000 ga	
Inflation Reduction Act Production Tax Credit for H2 Production ($/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%		

Benefit/Cost Analysis ($M in 2030)			
Utah H2 Benefits			
Annual H2 revenue at $/kg goal assumed.	$ 134		
Total Benefits		$ 134.30	
Utah H2 Operating Costs ($M)			
Stack depreciation as this is a consumable	$ 8.2		
Fixed O&M	$ 2.9		
Variable O&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**

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



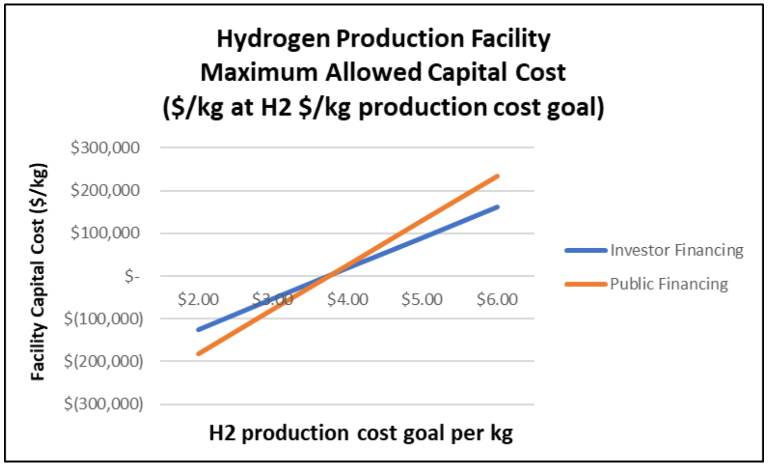


Exhibit V-7Z. Benefit/Cost Ratios Summary, All Scenarios

Scenario A, Add TransWest, Benefit/Cost Ratios

Asset Owner Type	Total Resource Perspective		RTO Perspective	
	Without ITC	With ITC	Without ITC	With ITC
Investor-Owned Financials	0.98	1.15	2.09	2.98
Public Power Financials				
Without hypothetical capital structure	1.63	1.85	4.21	5.99
With hypothetical capital structure			2.06	2.93

Scenario A, Add Soo Green, Benefit/Cost Ratios

Asset Owner Type	Total Resource Perspective		RTO Perspective	
	Without ITC	With ITC	Without ITC	With ITC
Investor-Owned Financials	0.19	0.27	0.19	0.27
Public Power Financials				
Without hypothetical capital structure	0.33	0.57	0.33	0.57
With hypothetical capital structure			0.19	0.27

Scenario B, Add Power from the Prairie to Scenario A, Benefit/Cost Ratios

Asset Owner Type	Total Resource Perspective		RTO Perspective	
	Without ITC	With ITC	Without ITC	With ITC
Investor-Owned Financials	0.63	0.82	0.84	1.20
Public 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 Ratios

Asset Owner Type	Total Resource Perspective		RTO Perspective	
	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

Asset Owner Type	Total Resource Perspective		RTO Perspective	
	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, Benefit/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%	0.5%	-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%

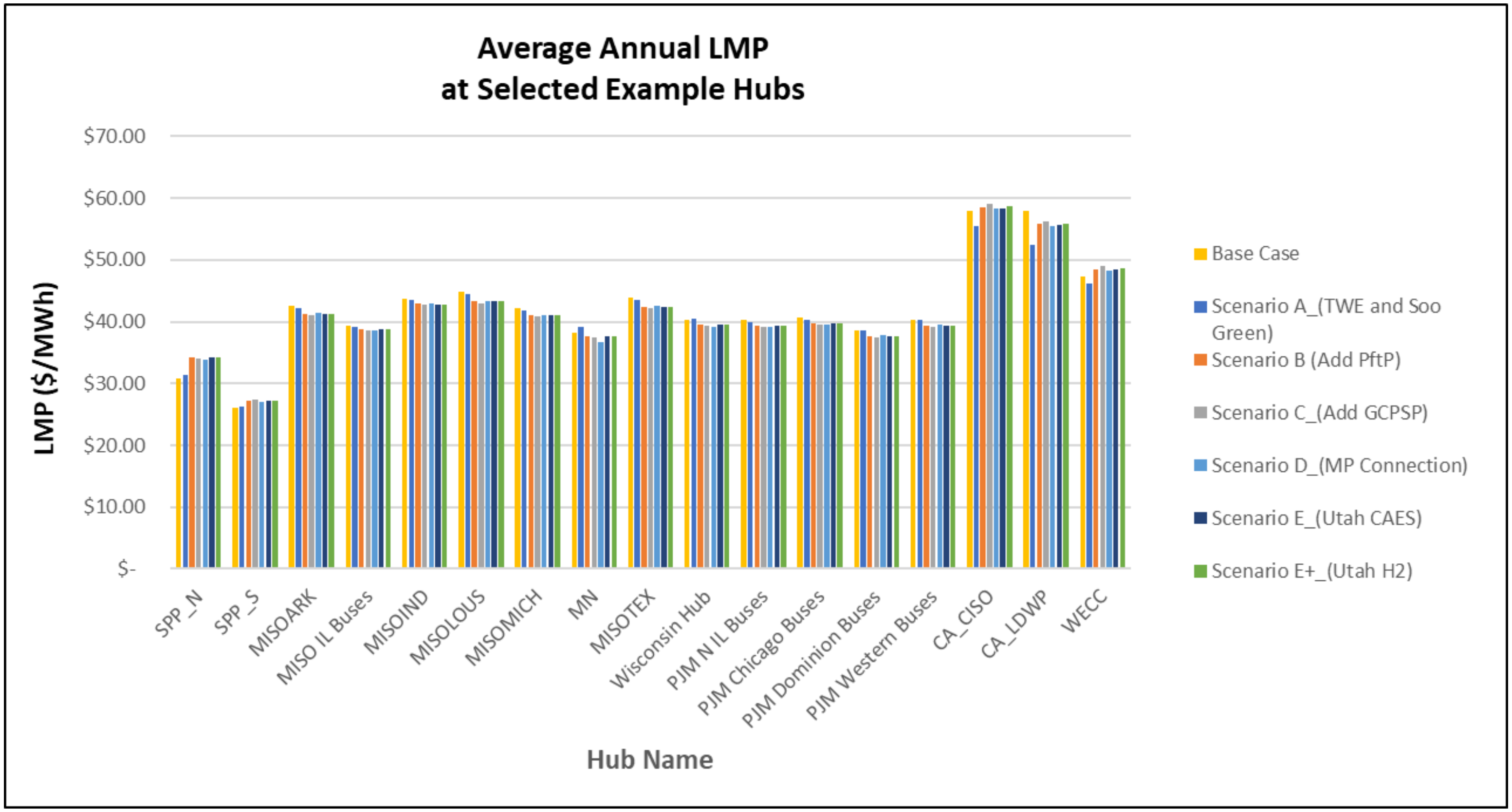
Scenario E

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%	0.0%	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%	0.0%	0.0%	0.0%	0.1%	0.1%	0.2%	0.3%	0.2%

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



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

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	0	0	0	0	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	0	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	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	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	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%

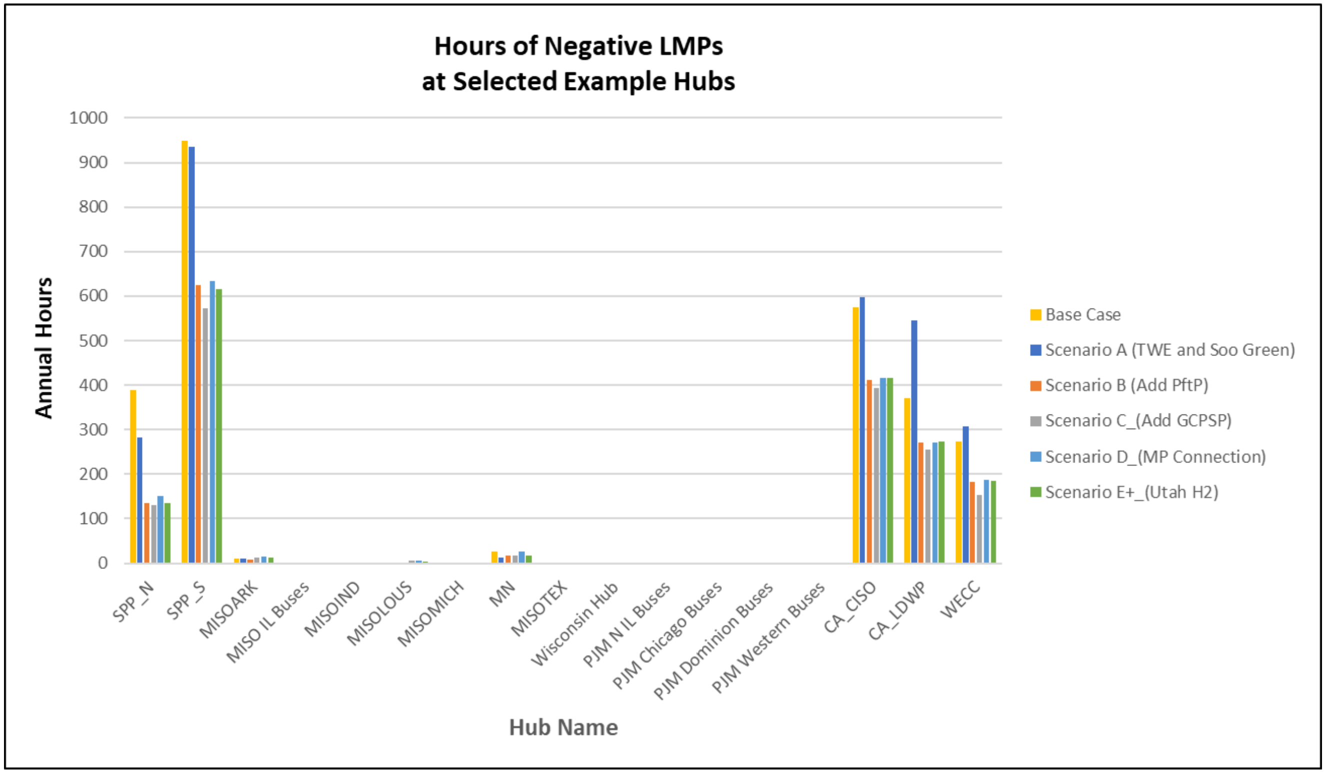
Scenario E

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	0	0	0	0	0	384	245	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%

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.
- 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

Scenario C – GCPSP Generation and Storage

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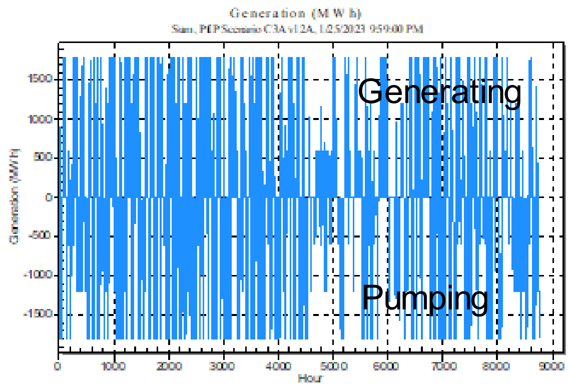

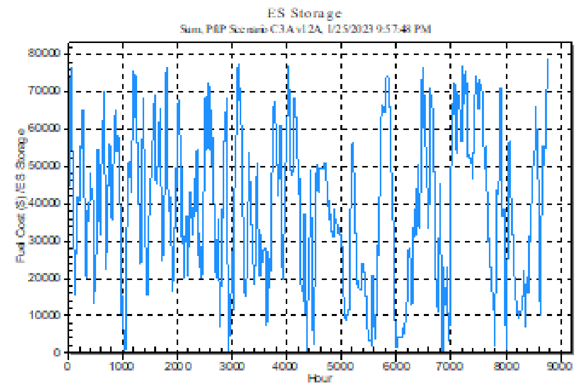

	Generating	Pumping	Zero
Hours	2193	2749	3818
Energy (MWh)	2,213,833	(3,118,145)	0
CF1	56.1%	63.0%	0
CF2	14.0%	19.8%	0

Hitachi Energy

- 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

Scenario E – CAES Generation and Storage

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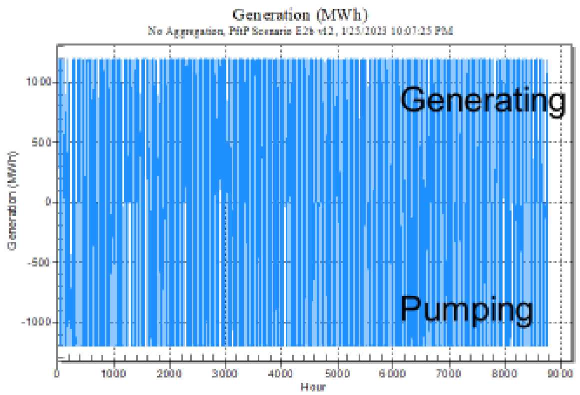
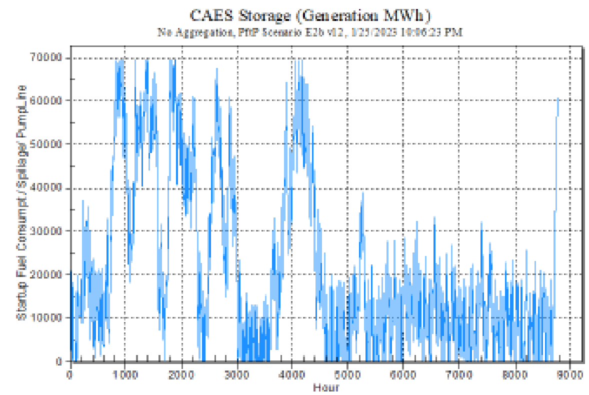


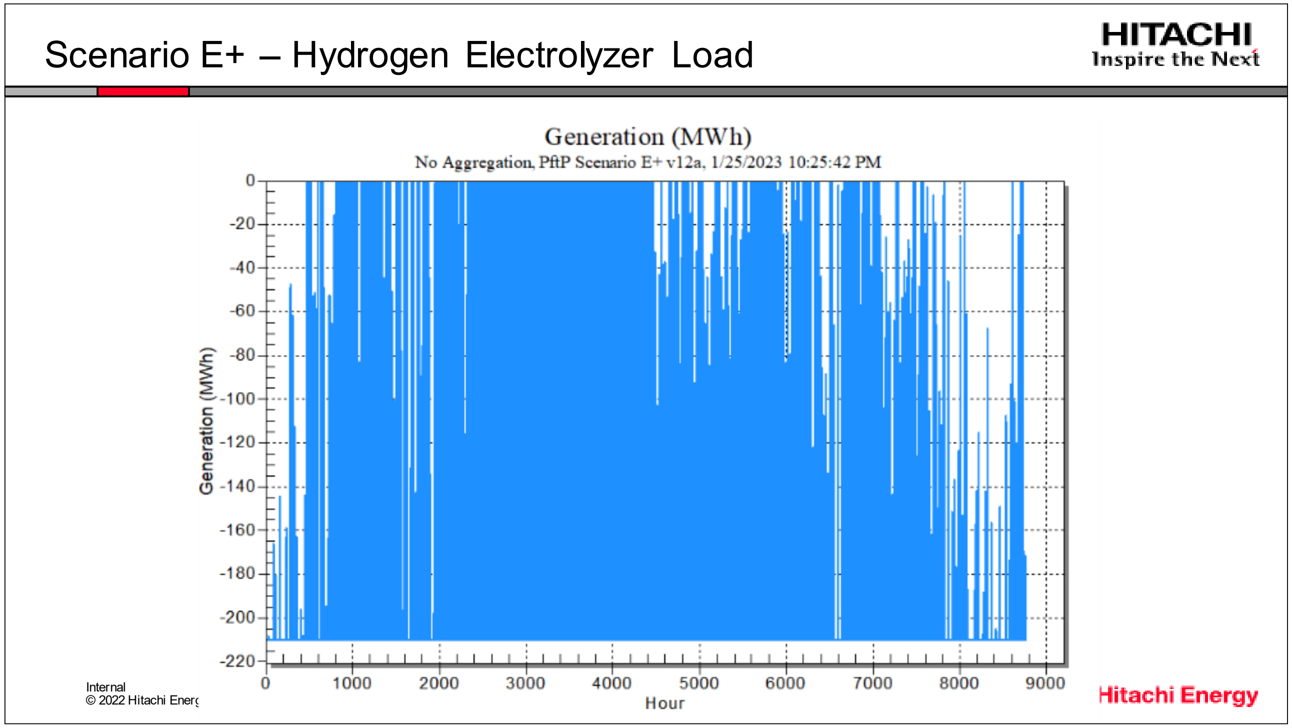


CAES	Generating	Pumping	Zero
Hours	4070	3303	1387
Energy (MWh)	4,231,395	(3,533,564)	0
CF1	86.6%	89.2%	0
CF2	40.3%	33.6%	0

Hitachi Energy

- Optimized CAES dispatch keeps underground 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.
- Storage activity greatest during first half of the year. Similar to effects shown on PftP line during first half of year.

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.