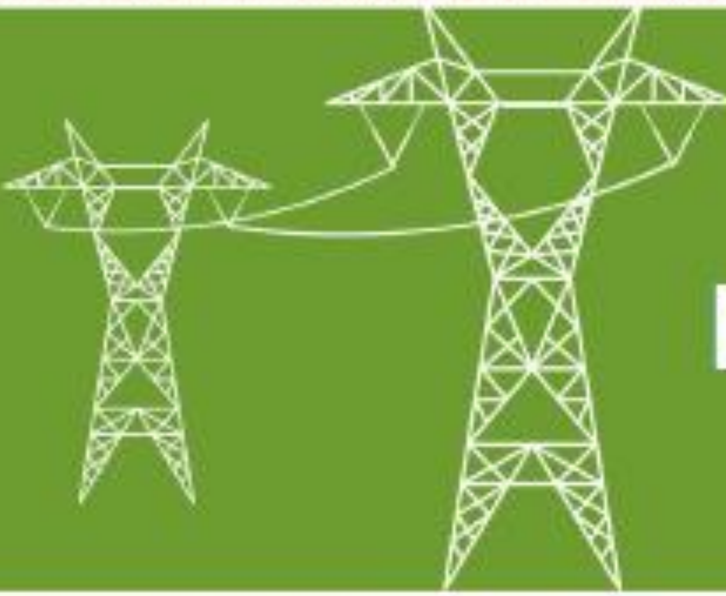
STUDY REPORT



POWER FROM THE PRAIRIE

Concept Development Study (CDS)

Volume 1:
Summary
PUBLIC EDITION

March 23, 2023

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I. TRANSMITTAL LETTER

March 23, 2023

RE: Power from the Prairie Project Concept Development Study—FINAL Report

Power from the Prairie LLC (PftP LLC, www.powerfromtheprairie.com) and our subcontractor Study Team member, Hitachi Energy, are pleased to provide the attached Final Report Volume 1[1] for the Power from the Prairie project Concept Development Study (CDS, or the "Study"). The CDS is Stage 1 of a proposed four-Stage PftP project.

This strategic business Study examines the potential use of high capacity, interregional electric high voltage direct current (HVDC) transmission to tap widely dispersed and time-diversified renewable energy sources from both planned and currently untapped remote regions to deliver more constant and reliable renewable energy to load centers. The system may also include grid-level, long duration energy storage where beneficial.

Going beyond technology alone, the CDS also examined how to organize, accomplish, operate, and regulate such an innovative project. The potential is reliable and cost-effective swaps of time-diversified renewable energy between Southern California and the Pacific Northwest to Chicago and Eastward. It could also enable cost-effective production of truly green hydrogen as an additional clean energy storage resource.

This privately funded study was performed with the direct involvement and cooperation of a diverse set of multiple, innovative, utility and developer CDS Participants with input from their Regional Transmission Organizations (RTOs) and Planning Authorities. This system concept is at the vanguard of renewable energy and energy storage development in multiple, multi-state regions and the nation. Once demonstrated in this pathfinder CDS, the study process is intended to be applicable and repeatable across the country.

Sincerely,

Bob Schulte

Bob Schulte
Managing Member

[1] Volumes 2 (Public) and 3 (Confidential) provide the Exhibits referenced in this Volume 1.

II. ACKNOWLEDGEMENTS

The contributions of the following individuals to this study are gratefully acknowledged:

The CDS Participants

Basin Electric Power Cooperative
BHE U.S. Transmission, LLC
Black Hills Corporation
Minnesota Power
Missouri River Energy Services
Omaha Public Power District
Southern California Public Power Authority/Burbank Water & Power

The Power from the Prairie LLC (PftP LLC) Study Team

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Hitachi Energy

The CDS Observers

James Okullo of Midcontinent Independent System Operator
Clint Savoy and Afshin Salehian of Southwest Power Pool
Saad Malik of Western Electricity Coordinating Council
and
Hamody Hindy, Carl Mas, and Tara Brown of U.S. DOE

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III. INTRODUCTION

This report summarizes the results of the Concept Development Study (CDS) for the Power from the Prairie (PftP) interregional transmission project (the "Project"). The purpose of the CDS was to provide the multiple utility and transmission/renewable energy developer CDS Participants with initial information to enable their strategic decisions regarding whether to proceed with a PftP project.

In contrast to previous interregional transmission studies typically performed by national labs or academia that are conceptual, the PftP CDS is the first public study of interregional transmission that involves specific utilities and transmission/renewable energy developers, and a specific project. It represents the first practical, pathfinding element in a nationwide high-voltage, direct current (HVDC) "macrogrid" buildout.[2]

A. OVERVIEW

Study Background

More than a decade after Federal Energy Regulatory Commission (FERC) Order 1000 suggested interregional transmission development, little has happened. There are many reasons for this.[3] A primary reason is that utilities generally do not think about or look beyond their own service territories.

Their Regional Transmission Organizations (RTO) have performed initial studies.[4] But other than projects to address cross-border interconnection issues along the immediate seams between them, they have not yet identified any truly interregional projects to implement. To-date, the benefits of interregional transmission have not been clearly defined, leading to disagreements in the benefit calculations and thus who pays for what. This has resulted in fewer, smaller projects moving forward because it is easier to agree on the benefits.

The CDS was developed and managed by PftP LLC, a limited liability company incorporated in Iowa. Comprised of former executives in public and investor-owned utilities and legal experts in energy and organization law, they designed the CDS to address the previous shortcomings in interregional development and be "productively

[2] In the PftP project context for this CDS, "interregional" means spanning not only between RTOs/ISOs, but also between the Western and Eastern Interconnections. PftP would do both.
[3] R. Schulte and F. Fletcher, "Why the Vision of Interregional Transmission Development in FERC Order 1000 is Not Happening", The Electricity Journal, April 2020, available at: www.powerfromtheprairie.com/publications.
[4] Notably, the Midcontinent Independent System Operator (MISO) and Southwest Power Pool (SPP) "Joint Targeted Interconnection Queue Study", and MISO's "Targeted Market Efficiency Projects" study with PJM.

disruptive" of legacy industry planning processes. See Sections XI, XII and XIII for details about PftP LLC, Hitachi Energy, and the CDS Study Team, respectively.

The PftP LLC organization and the CDS were designed based on lessons learned from previous HVDC transmission projects. Instead of the traditional, merchant, interregional transmission project approach of "build it and they will come" (i.e., develop a transmission project and then seek shipper and off-taker customers for it), the CDS starts with involvement of potential utility off-takers and renewables developers up-front.

Instead of a long, point-to-point HVDC line crossing multiple states uninterrupted[5] and thereby making those states "flyover land"[6] from a community benefits perspective, the PftP project features multiple on-ramps and off-ramps involving each state along the way.

And instead of a transmission vendor or individual utility who are naturally self-focused in performing the study, PftP LLC acted as an objective, neutral, third-party to coordinate and perform due diligence on the project concept for the CDS Participants. Then they can make their own decisions about what should happen next.[7]

The CDS Participants

PftP LLC designed the CDS and started recruiting CDS Participants in 2016. This involved extensive virtual and in-person contacts and meetings with most of the utilities in the Upper Midwest and several in Southern California, RTOs Midcontinent Independent System Operator (MISO) and Southwest Power Pool (SPP) and planning entities including the Western Electricity Coordinating Council (WECC) and others. Plus, discussions with multiple independent transmission companies and renewables developers.

The result of these contacts identified the following CDS Participants among others, and contractual arrangements were completed with them in early 2022. In contrast to typical entities, these CDS Participants can apparently think outside their own boundaries. The PftP CDS Team calls them: a "coalition of the willing":

- Basin Electric Power Cooperative (BEPC)
- BHE US Transmission Company, LLC (BHEUST), including their regulated utility affiliates.

[5] Purely point-to-point HVDC projects do have useful applications. But not for a multi-state project like PftP.
[6] The term "flyover land" refers to a project that passes over or through a region without touching or benefitting it.
[7] This approach was used by Study Team members in the due diligence for the Iowa Stored Energy Park project. R Schulte, Nick Critelli et all, *"Lessons from Iowa"*, U.S. DOE/Sandia Labs Report #SAND2012-0388, January 2012. *Available at:* www.lessonsfromiowa.org and www.powerfromtheprairie.com/publications.

- Black Hills Corporation (BHC), including their regulated utility affiliates.
- Minnesota Power (MP)
- Missouri River Energy Services (MRES)
- Omaha Public Power District (OPPD)
- Southern California Public Power District (SCPPA), represented by their member, Burbank Water & Power (BWP)

Two Participants in-turn each represented three regulated utility affiliates (Exhibit III-1). This is a very diverse, public and investor-owned group. This is important because the primary issues involved in accomplishing an interregional transmission project are not technical. They are geopolitical, organizational, and regulatory.

The Participants' Motivations

At the start of the CDS, the CDS Participants were polled regarding their motivations for being involved in the study. The results of the poll are detailed at Exhibit III-2.

The top motivations of the CDS Participants were:

1. A desire to own transmission for purposes of reliability, resiliency, economical cost of service, access to additional renewables, and as an investment, plus:

2. To achieve higher levels of renewables than they could do themselves in their own territories, both by increased access to renewables supplies and time diversity compared to their own local renewables.

All but one of the Participants are interested in owning a portion of the Power from the Prairie line.[8]

The PftP Project

Power from the Prairie is a proposed, nominal 4,000 Megawatt (MW) interregional HVDC transmission line. Consisting of multiple line segments between its five HVDC converters, it would extend from the wind fields of Wyoming, crossing either Nebraska or South Dakota, to the wind fields of Iowa (Figure III-1). It would feature multiple DC/AC/DC terminals in the middle, enabling interconnection of thousands of MW of additional new renewables in some of the best wind resources in the country. These resources are remote from loads and currently landlocked due to lack of transmission and access to markets.

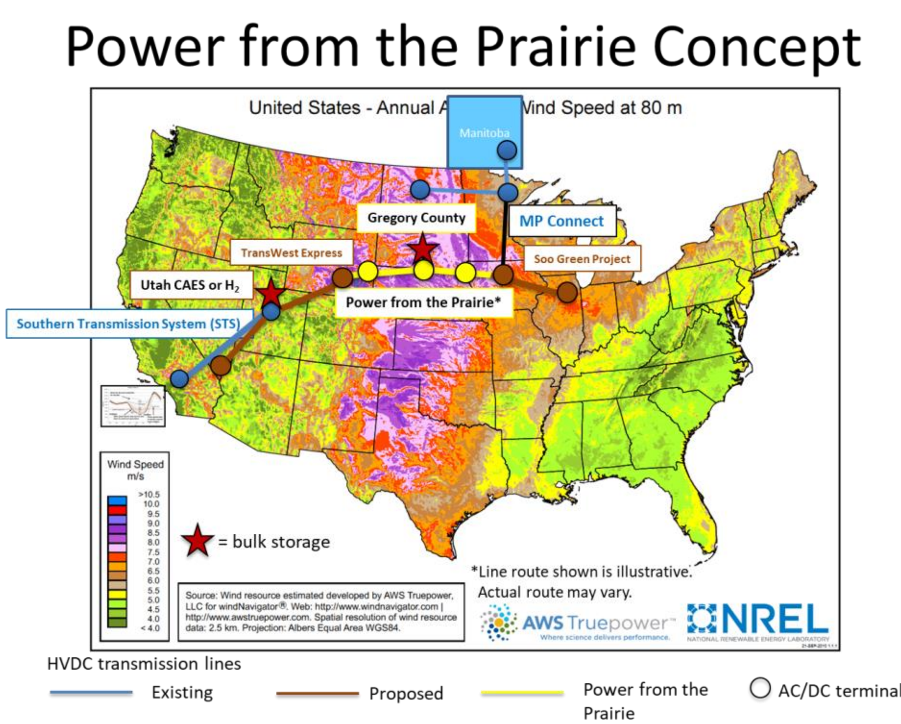
[8] Understandably, the one exception was the Participant located in Southern California.

The Project would span the seam between the Western and Eastern Interconnections of the electric grid that currently operate asynchronously, with limited transfer capability across their common seam. That is, they do not operate in synch with each other, severely limiting energy transfers between them. PftP would increase the current total DC transfer capacity across this national seam barrier (including all seven existing DC ties of about 200 MW each) by 286% in both directions. A good start and down payment on needed interregional transfer capacity for the future.

Combined with other existing and proposed HVDC projects to its West (TransWest Express) and East (Soo Green), PftP would represent the completing link in an interregional HVDC transmission superhighway from the West Coast to Chicago, and Eastward to the PJM Interconnection (PJM).

And, unlike currently proposed HVDC projects that are typically designed to primarily move renewables unidirectionally to load, the addition of PftP would make them *bi-directional*. This would enable swaps of time-diversified renewables energy across their entire span, including swaps of surplus solar energy in the West for surplus wind energy in the Midwest. And it could also accommodate grid-level energy storage and facilitate green hydrogen development. All of these were examined in the CDS.

FIGURE III-1. The Power from the Prairie Project Concept



B. STUDY PROCESS AND TASKS

The study was not a transmission technical study. Instead, it entailed a strategic business assessment to help the CDS Participants determine whether a Power from the Prairie project would be beneficial to them and their members or customers. And what it will take to organizationally accomplish, operate, and regulate such a system.

The study entailed the following Tasks:

- Task 1: Modeling
- Task 2A: Technology
- Task 2B: Relationship to Markets
- Task 3A: Organization
- Task 3B: Regulatory
- Task 4: Study Management

Detailed discussion and conclusions of each of these Tasks is provided in the following Sections.

The CDS Review Committee of the Participants met monthly to provide input and review of the study approach and progress. Four Subcommittees on the various Tasks also met monthly to review details and provide input to the Review Committee. Exhibit III-3 lists the members of the Review Committee and Subcommittees.

Also, staffs of MISO, SPP, WECC and the U.S. Department of Energy (DOE) served as observers throughout the study. The results of the CDS as summarized in this report will be the basis for decisions by the CDS Participants and others regarding potential next steps toward “Stage 2” of a Power from the Prairie project.

IV. EXECUTIVE SUMMARY

A. STUDY CONCLUSIONS

The conclusions of the study are as follows:

1. The Bottom Line

The proposed 4,000 MW Power from the Prairie project represents an initial installment in a nationwide Interregional HVDC transmission "macrogrid" overlay on the legacy alternating current (AC) system. A very innovative solution using currently available HVDC technology, it would support the ongoing energy transition in an economical way while also enhancing grid reliability and resiliency.

- ✓ **Pathfinding 4,000 MW interregional HVDC transmission project.**
- ✓ **$14 Billion new transmission and renewables infrastructure investment.**
- ✓ **3,000 MW and 8.9 TWh of new renewables.**
- ✓ **Multi-state benefits.**
- ✓ **7.3 million metric tons carbon reduction.**
- ✓ **Modest impacts on customer rates.**
- ✓ **Innovative Public-Private Partnership organization approach.**
- ✓ **Key regulatory innovations needed.**
- ✓ **Study process repeatable elsewhere in the country.**

Rather than using HVDC converters only at its ends in Wyoming and Iowa, true to its name it will provide renewable energy on-ramps at three additional locations in multiple states along its 970 line-mile span. This is some of the richest wind energy resources in the nation, and currently landlocked due to lack of transmission to remote markets.

The project and its associated renewables would have a capital cost of approximately $14 Billion ($9 Billion for the PftP line, and $5 Billion for the renewables). Based on the assumptions used in the analysis, for public power and other governmental owners, the project would have beneficial effects on consumers' electric rates.

Private equity-based owners have higher financial requirements and related income tax effects. For them, the project would have modest increasing effects on consumer electric rates, assuming such projects are made eligible for similar federal income tax credit (ITC) treatment available to renewable and storage projects in the recent Inflation Reduction Act (IRA).[9] Interregional transmission is intended to enable such facilities.

The project would enable interconnection of more than 3,000 MW (8.9 TWh) of new renewable resources. It would more efficiently integrate the current multiple, lengthy, and inefficient generation interconnection queues processes involved in doing relatively small clusters of individual renewables projects one-at-a-time by bundling them together in a common request.[10] The combination of transmission and the new renewables would

[9] Such an ITC for transmission is already contained in proposed federal legislation (S.1016, Heinrich).
[10] While reducing the need for interconnection studies for multiple small projects, the interconnection request process for PftP in multiple markets will be significant.

reduce annual carbon emissions by 7.3 million metric tons—the equivalent of taking 1.6 million gasoline-fueled automobiles off the road.

Other projects associated with PftP including the Gregory County Pumped Storage Project (GCPSP) would enable 1,800 MW of additional renewables and reduce annual carbon emissions by an additional 1.5 million metric tons. The Minnesota Power Connection HVDC project when connected to PftP would enable another 2,500 MW of renewables and further reduce emissions by another 4.2 million tons.

Looking beyond the 3,000 MW of new renewables assumed installed with the PftP line, the total new renewable resources examined in this CDS total nearly 12 Gigawatts (GW) of installed capacity.

These Stage 1, high-level initial results are subject to further improvement via cost and performance optimization in Stage 2 of the project.

2. System economics.

- There are two perspectives involved in the economic analysis:
  - *Total Resource Perspective (TRP)*. This includes all investment costs in transmission, renewables, and storage compared to production costs and other benefits. It is a measure of whether the project will pay for itself and reflects the potential impact on future customer rates.
  - *RTO Perspective (RTOP)*. This is a measure of whether an RTO in its own analysis would approve the project in its planning and cost recovery processes. The calculations are the same as the Total Resource Perspective but excludes the investment cost in the project's renewables.[11]

- Depending on the project participant's specific situation, their perspective will affect their economic results depending upon whether they are public-, or investor-financed. Also, within public power, their RTO Perspective will vary whether or not they use a hypothetical capital structure in their RTO ratemaking.[12] And the presence or absence of federal investment tax credits (ITC) for transmission or storage also affect the benefit/cost results. The CDS calculated benefit/cost ratios for all of these combinations so the Participants can choose which ratios relate to them.

- The system economics involved performing nodal production cost modeling of the U.S. electric grid from the West Coast to the PJM Interconnection (PJM).

[11] RTOs rightfully focus on transmission costs. Their transmission planning analyses typically assume a future level of renewables development. The investment cost of the associated renewable developments is not in their purview.
[12] Hypothetical capital structures are discussed in more detail in Section V.

- The CDS compared estimated annual fixed charges on the project to corresponding production cost savings.
  - The production cost savings taken alone are a conservative estimate of benefits. Analysis and quantification of potential additional benefits including enhanced reliability, resiliency and resource adequacy, interregional generation capacity sharing and increased reliability of time-diversified renewables when aggregated together using interregional transmission were beyond the scope of this study.
  - As discussed in Section V, other industry studies suggest that production cost savings alone as calculated in this CDS may be only a portion of the total benefits available if all the benefits above are included. This means *the actual benefit/cost ratios over time may be materially higher than those calculated here*. This will be a topic for further analysis in Stage 2 of the PftP project.
  - The results also do not include future effects of increasing natural gas prices or emissions costs.[13] Or increases in future electric loads due to increasing electrification. The results do not consider potential societal or indirect benefits such as job creation, tax base, or associated economic activity related to the projects.
  - The PftP Study Team believes including such considerations would likely further increase the benefits calculated in this study, and thereby increase benefit/cost ratios of the projects examined beyond those calculated in this CDS.

- The total annual production cost (fuel, purchases and other costs, net of sales revenues) in all regions for the Base Case was about $67 Billion in Study Year 2030.

- In Scenario A (adding the TransWest Express and Soo Green HVDC projects to the Base Case) prior to and without the addition of PftP results in a total annual regional production cost reduction of about $790 million.
  - About $717 million of these savings happen in the Western Electricity Coordinating Council (WECC), so are attributable to the TransWest Express project.[14]
  - About $73 million of these savings happen in non-WECC areas (i.e., the Eastern Interconnection), so are attributable to the Soo Green project.

- In Scenario A, the TransWest Express HVDC line project with its affiliated new renewables it enables[15] and without PftP:

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[13] The CDS Participants agreed to use a planning cost for carbon emissions of $16/metric ton in Year 2030 for this CDS. This was based on the Regional Greenhous Gas Initiative (RGGI) estimates of such costs in 2030, and the mid-value of planning assumptions the Minnesota Public Utilities Commission (MPUC) requires utilities to use in their Integrated Resource Plans (IRP). This assumption was a compromise. Some national entities would prefer a cost of zero. Others, particularly environmental organizations, would demand a number much higher than $16.

[14] Current transfer capacity between the Western and Eastern Interconnections is very limited.

[15] The term "enables" means the project facilitates installation of additional renewables that would not be possible without the project.

  - Has a Total Resource Perspective (TRP) benefit/cost ratio[16] of 0.98, using investor-owned facility financing which is appropriate for such merchant facilities. With a federal investment tax credit (ITC) for transmission, this would improve to 1.15.
    - For comparison, the same facilities using public power financing would have a TRP benefit/cost ratio of 1.63.[17] With a transmission ITC, this improves to 1.85.
  - Has RTO Perspective (RTOP) benefit/cost ratios using investor-owned facility financing of 2.09 and 2.98, measured without and with an ITC, respectively.[18]
    - For comparison, the same facilities using public power financing without a hypothetical capital structure would have RTOP benefit/cost ratios of 4.21 to 5.99 without and with an ITC, respectively. With a hypothetical capital structure, the corresponding ratios would be 2.06 and 2.93, without and with an ITC, respectively.

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

  - Reduces total carbon emissions in WECC by 4.8 million metric tons/year.
  - Increases the total energy flow of the existing Southern Transmission System (STS) HVDC line in both directions compared to Scenario A.

- In Scenario A, the Soo Green HVDC project without enabling new renewables and without PftP:
  - Has a TRP benefit/cost ratio of 0.19 using investor-owned financing which is appropriate for such merchant facilities. This ratio improves to 0.27 if a transmission ITC is applied.

[16] In the total Resource Perspective, a benefit/cost ratio of 1.0 means the project's benefits equal its costs while fulfilling the project owner's financial return requirements. A ratio greater than 1.0 means the benefits exceed the costs, implying the project would be beneficial to consumers' rates while fulfilling the project owner's financial return requirements. A ratio less than 1.0 means the costs exceed the benefits, implying the project would tend to increase consumers' rates while fulfilling the project owner's financial return requirements.

[17] Although not applicable to TransWest as a merchant, the public power benefit/cost ratio is shown here to illustrate that, for projects with multi-billion-dollar capital costs as examined in this study, the project financing matters to the benefit/cost ratio.

[18] TransWest is a merchant project that does not plan to accomplish its cost recovery via an RTO. The RTOP cost/benefit ratios shown here are for illustrative purposes only, for comparison to the other Scenarios.

        - For comparison, the same facilities using public power financing would still have a low TRP benefit/cost ratio of 0.33 without and ITC, and 0.57 with an ITC.
    - Has RTOP benefit/cost ratios similar to the TRP ratios because renewables investment is not involved.[19]

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

    - The relatively low benefit/cost ratios are attributable to the fact that:
        - While the project provides additional market opportunities and price arbitrage for existing renewables, the CDS modeling assumed the project does not *enable* additional new renewables.
        - The relatively modest benefit/cost ratios of Soo Green in this CDS, determined using a utility's planning perspective, does not mean Soo Green is not a viable project. For example, if a renewable shipper used Soo Green to contractually sell their energy and capacity markets in PJM, that would mean Soo Green was enabling the transaction and could have a reasonable benefit/cost ratio from the shipper's and off-taker's perspectives. Thus, a merchant transmission owners' perspective on economics may be different from the utility perspective used in the CDS.
    - Reduces total regional carbon emissions by about 909,000 metric tons/year.

- Scenario B (adding the PftP line project and 3,000 MW of additional renewables it enables to Scenario A) results in an incremental total annual regional production cost reduction of about $816 million compared to Scenario A.[20]

- The PftP HVDC line project with the affiliated new renewables it enables:
    - Has a TRP benefit/cost ratio of 1.15 using public power financing.
        - With a federal ITC, this would improve further to 1.44.[21]

[19] Similar to TransWest, Soo Green is a merchant project that does not plan to accomplish its cost recovery via an RTO. The RTOP cost/benefit ratios shown here are for illustrative purposes only, for comparison to the other Scenarios.

[20] This $816M benefit of PftP is *in addition to* the $790M benefit in Scenario A, compared to the Base Case.

[21] Assuming public power would be eligible for ITC benefits, like they are for renewables and storage in the Inflation Reduction Act.

- Has an RTOP benefit/cost ratio of 1.67 to 2.38, measured without or with a transmission ITC, respectively for public power without a hypothetical capital structure.
  - The corresponding benefit/cost ratio with a hypothetical capital structure is 0.82 to 1.16, again without or with an ITC, respectively.
- Has a TRP benefit/cost ratio of 0.63 using investor-owned financing.
  - The proposed federal income tax credit on such HVDC and HVAC transmission facilities similar to that offered to renewables and storage in the Inflation Reduction Act (IRA) would make this benefit/cost ratio 0.82.[22]
- For investor-owned financing, has an RTOP benefit/cost ratio of 0.84 to 1.20, measured without or with a transmission ITC, respectively.

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

- Increases new renewable energy generation by 8.9 million MWh (8.9 TWh).
- Reduces curtailment of existing renewable generation by 3 million MWh (3 TWh).
- Reduces total carbon emissions by an additional 7.3 million metric tons per year compared to Scenario A.
- Increases the energy flow of the TransWest HVDC project by 2 million MWh (10%) North-to-South, and 1 million MWh (368%) South-to-North.
- Decreases the energy flow of the Soo Green HVDC project by 670,000 MWh, or 4.5%.
  - Adding the PftP line introduces additional markets to the West for generation in MISO, reducing flows to the East on Soo Green.
- Further increases the total energy flow of the existing Southern Transmission System (STS) HVDC line by:
  - 811,000 MWh (or 7.5%) North-to-South (Utah to California) and 512,000 MWh (or 594%) South-to-North (California to Utah) compared to Scenario A.

[22] The recently passed federal Inflation Reduction Act (IRA) offers a 30% ITC to renewables and energy storage projects. A similar ITC for transmission was introduced in the IRA discussion, (S.1016, Heinrich) but was not included in the final bill.

- Scenario C (add the Gregory County Pumped Storage Project (GCPSP) to Scenario B) results in an incremental annual production cost savings of $[CONFIDENTIAL] million.[23]

- GCPSP with the associated new renewables it enables, when added to PftP:
  - Has a benefit/cost ratio of [CONFIDENTIAL] using public power financing.
    - If the federal income tax credit of 30% on storage in the Inflation Reduction Act was applied to GCPSP, the project would have benefit/cost ratio of [CONFIDENTIAL].
  - Has a benefit/cost ratio of [CONFIDENTIAL] using investor-owned financing.
    - If the federal income tax credit on storage in the Inflation Reduction Act was applied to GCPSP, the project would have significantly improved benefit/cost ratio of [CONFIDENTIAL].
  - Reduces carbon emissions by an additional 1.5 million metric tons per year compared to Scenario B.

- Scenario D (adding the Minnesota Power (MP) Connection to Scenario B) results in an incremental total annual regional production cost reduction of about $314 million.

- The Minnesota Power Connection and the associated additional renewables they enable, when added to PftP in Scenario B:
  - Has a TRP benefit/cost ratio of 0.56 using investor-owned financing, which is appropriate for an IOU like MP.
    - The proposed federal income tax credit of 30% on such interregional HVDC transmission facilities would make this benefit/cost ratio 0.76.[24]
  - For investor-owned financing, has an RTOP benefit/cost ratio of 1.05 to 1.49, measured without or with a transmission ITC, respectively.
  - Has a TRP benefit/cost ratio of 1.0 for public power financing.
    - Which would increase to 1.15 with the proposed federal ITC for transmission.[25]
  - Has an RTOP benefit/cost ratio of 2.24 to 3.19, measured without or with a transmission ITC, respectively for public power with a hypothetical capital structure.
    - The corresponding benefit/cost ratio with a hypothetical capital structure is 1.10 to 1.56, again without or with an ITC, respectively.

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[23] The GCPSP project owners are MRES and MidAmerican Energy (MEC), both CDS Participants. The economic results for GCPSP are confidential to them and provided in Volume 3 (Non-Public) of this Report.
[24] *Id*.
[25] This assumes public power could receive the benefit of the ITC, as they would get from the IRA's treatment of ITC for renewables and storage. The CDS modeling indicates several public power entities would benefit from the MP Connection, in addition to Minnesota Power.

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

- Reduces total regional carbon emissions by an incremental 4.2 million metric tons per year.
- Has a minimal impact on the energy flow (and profitability) of the TransWest HVDC project.
- Increases the energy flow of the Soo Green HVDC project by 489,000 MWh (or 4%) West-to-East and decreases it by 50,000 MWh (or 20%) East-to-West.
- Has minimal effect on the energy flows of the PftP, TWE or STS HVDC lines.

- Scenario E (add a compressed air energy storage (CAES) facility with 1,200 MW of additional renewables in Utah to Scenario B) results in an incremental total annual production cost reduction of about $177 million. Most of these savings would occur in WECC.

- The addition of a merchant CAES facility in Utah to the HVDC system and enabling 1,200 MW of additional renewables:
  - Has a TRP benefit/cost ratio of 0.57 using investor-owned financing.
    - Assuming the ITC of 30% on storage in the IRA applies to this project, the resulting benefit/cost ratio would be 0.69.
  - For investor-owned financing, has an RTOP benefit/cost ratio of 0.74 to 0.96, measured without or with a transmission ITC, respectively.
  - Has a TRP benefit/cost ratio of 0.67 using public power financing.
    - Assuming the ITC of 30% on storage in the IRA applies to this project, the resulting benefit/cost ratio would be 0.80.
  - Has an RTOP benefit/cost ratio of 0.86 to 1.08, measured without or with a transmission ITC, respectively for public power without a hypothetical capital structure.
    - The corresponding benefit/cost ratio with a hypothetical capital structure is the same as without, because the CAES facility, itself operating as a transmission asset, does not require additional transmission facilities.

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

- Would decrease carbon emissions by 1.5 million metric tons per year.

- Scenario E+ (add an electrolyzer-based hydrogen production facility in Utah to Scenario B) results in an incremental total annual regional production cost *increase* of about $72 million.

- The addition of a 210 MW, merchant, electrolyzer-based hydrogen production facility in Utah to the HVDC system:
  - Does not necessarily represent a "green" hydrogen production facility.[26]
  - Would experience an annual cost of electric energy supply of $83 million (an average $58.16/MWh cost for the electrolyzer facility). This is equivalent to $2.46/kg of H2 produced for the commodity energy supply alone, without regard to related fixed and operating costs for the electrolyzer.
  - Would *increase* annual electric grid carbon emissions by 539,000 metric tons during its production cycle.
  - But its H2 product could offset 202,000 metric tons/year of carbon emissions if used to fuel an otherwise natural-gas-fired combined cycle combustion turbine generator or other combustion-related end-use—still a net increase of about 337,000 metric tons of carbon.

- General conclusions of the economic analysis:
  - Project benefits based on production costs alone do not include all the potential benefits of the various Scenarios. Additional benefits to be examined in Stage 2 may be similar in magnitude. This means *the actual benefit/cost ratios will likely be higher* than what was calculated in this CDS and shown in this Report.
  - The total benefits of the above options to the RTOs/Planning Regions in most of the Scenarios are much larger than the total benefits to the CDS Participants.
    - As a practical matter, the CDS Participants do not constitute the entire census of members of the RTOs.

[26] This analysis assumed the electrolyzer's electric supply would be what is available on the grid. Even if the electrolyzer had contracted for renewable energy via PPA, its operation would still cause increases in operation of fossil units unless the renewables were hard-wired to the electrolyzer and were its exclusive supply.

        - This also indicates that entities other than the CDS Participants are benefitting from the various options.
        - And it indicates some form of cost sharing across the RTOs/Planning Regions would be reasonable in those Scenarios, based on benefits received. See the Task 3B Regulatory discussion in Section IX.
        - A large portion of the difference results from the fact that for the most part the CDS Participants did not claim rights to the high levels of assumed new renewables. If they did, they would claw back from otherwise “free riders” in the regions a large portion of the benefits for themselves. This will be a topic for Stage 2 of the Project.
    - Because of the very large capital costs involved in the options (multiple billions of dollars), the method of financing (public or private) has a large impact on their benefit/cost ratios.
        - Public power has a financing advantage over investor-owned entities. This is illustrated in their relative benefit/cost ratios for the same projects.
        - Some form of state or federal ownership or financing involvement may be beneficial. Example: federal ITC treatment for qualifying interregional transmission or storage facilities that enable renewables, or WAPA ownership of transmission or storage facilities.
    - Transmission or energy storage projects that enable additional renewables to be installed have much better economics than those that merely provide additional market access or price arbitrage for already-existing renewables that they did not enable.
    - The various Scenarios include a total of 12 GW of additional renewables (3 GW for Power from the Prairie alone). In the modeling, most of these (and their associated market value) were not assigned to any off-taker. This is an opportunity for utilities, corporations, and other off-takers to decarbonize their portfolio by pursuing ownership of them.

3. Technology

- Of the currently available HVDC technology options for the PftP project, Voltage Source Converter (VSC) technology is preferable to Load Commutated Converter (LCC).

- Among other things, VSC technology enables cost savings using multi-terminal applications as the many PftP converter locations were added to enable interconnection of renewables and PftP benefits for multiple states.

4. Relationship to Markets.

- A Power from the Prairie interregional HVDC transmission line would not require reorganization or mergers of the existing RTOs or necessarily a new consolidated RTO in the West.
    - Although it will likely require some changes in planning processes and administrative procedures.
        - Example: In spite of the vision of FERC Order 1000, there currently are no established processes for multiple RTOs jointly planning interregional transmission lines or consistent cost recovery processes for them.
        - Example: The effective load carrying capacity (ELCC) value of combinations of widely dispersed and time-differentiated renewables made possible by interregional lines would be greater than the same renewables viewed individually as they currently are in individual RTOs.

- A PftP line would schedule its renewables and load and bid its generation into the existing RTOs as a market participant in them.

- Because of the geographic span of PftP, a single RTO operating only within its own territory lacks the field of vision to successfully operate PftP.
    - A new entity, or interregional transmission organization (the PftP ITO)[27] will be necessary to schedule such interregional HVDC lines.
        - The ITO would be a market participant in multiple RTOs.
    - Like the RTOs, the ITO would be subject to FERC regulation and approval.

- Access to widely dispersed and time-differentiated renewables over interregional transmission lines creates new and previously unavailable opportunities for renewable energy swaps between regions, taking advantage of the renewables/load mismatches within the regions and the LMP differences between them. Grid-level energy storage on an interregional transmission line may be a particular beneficiary of such a capability.
    - These opportunities suggest another new entity, a power marketer called "The Federation," to define and monetize them.
    - The Federation would also be subject to FERC regulation and approval as a power marketer. It would be a market participant in the ITO.

5. Project Organization.

- Organization of the PftP project would entail four Stages:

[27] The Electrical Systems Integration Group (ESIG) calls this concept a "macrogrid operator". Jay Caspary of Grid Strategies LLC presentation to CDS Review Committee, April 19, 2022.

   - Stage 1: The Concept Development Study (i.e., this study).
   - Stage 2: Proof of Concept.
   - Stage 3: Development.
   - Stage 4: Design, Build and Operate.

- The PftP project would entail three organizations:
   - The PftP Public-Private Partnership, a Limited Liability Partnership (LLP).
   - The PftP ITO, a 501(c) non-profit similar to an RTO.
   - The Federation, a limited liability company (LLC) power marketer.

6. Regulatory Issues.

- Many aspects of the electric energy industry are highly regulated and transmission lines are no exception. States have jurisdiction over permitting high-voltage transmission lines; however, FERC has limited jurisdiction under certain circumstances. This report addresses the permitting process for each state the PftP transmission line may cross along with FERC's limited authority over siting transmission lines and overall challenges.

- The current regulatory environment creates barriers to interregional transmission lines, especially in the area of cost allocation and cost recovery. Developers are largely left to recover costs from the transmission line customers and cannot recover costs on a broader basis that would include other beneficiaries of the interregional transmission line. Examples of spreading costs on a regional basis exist but interregional transmission projects are restricted to the regulatory framework established in FERC Order 1000, which has to-date failed to fulfill its purpose.

B. NEEDED NEXT STEPS

1. The PftP Project

- CDS Participants and others review and approve Stage 2, Proof of Concept, of the PftP project, as described in Section VIII and to be proposed in detail by the PftP LLC Team following this Stage 1 CDS.

2. FERC/State Joint Activities

- Successfully and productively complete current federal/state Joint Task Force efforts to better coordinate transmission planning efforts.

3. FERC Activities

- Establish an interregional transmission planning process across all RTOs.

- Establish an interregional transmission cost recovery process across all RTOs.
  - Because interregional facilities like PftP often result in widespread, multi-regional benefits beyond and larger than those of the Project owners alone, the Commission may anticipate that such processes may involve cost recovery spread across entire RTOs, or multiple RTOs.[28]
  - And the benefits to one region may result from interregional asset investments made in other regions.

- Review and approve via rulemaking a definition of Effective load Carrying Capability (ELCC) Resource Adequacy (RA) for shared assets to make them RA-eligible. Right now, a capacity resource can only be counted in one jurisdiction. Time-diversified renewables across multiple regions when aggregated together are more reliable than individual renewables sites alone and should be recognized as such. Their aggregated capacity value may still differ somewhat between RTOs, because the timing of the RTOs' peak load events is different.

- Review and approve via rulemaking a pro forma structure for Interregional Transmission Organizations (ITO).

- Review and approve a pro forma structure for interregional power marketers like The Federation—probably initially on a specific, case-by-case basis.

4. Congressional Activities

- Secure passage of proposed legislation[29] to provide investment tax credits (ITC) for HVDC and HVAC transmission like those provided to renewables and storage in the Inflation Reduction Act.

- In rulemaking for the IRA, confirm pumped hydro and compressed air energy storage (CAES) technologies as eligible for the ITC treatment offered to storage.

V. TASK 1: MODELING AND ECONOMICS

A. THE BASE CASE

1. Definition

For purposes of comparison, a Base Case was constructed representing the projected status quo in Year 2030 of the Western Electricity Coordinating Council (WECC),

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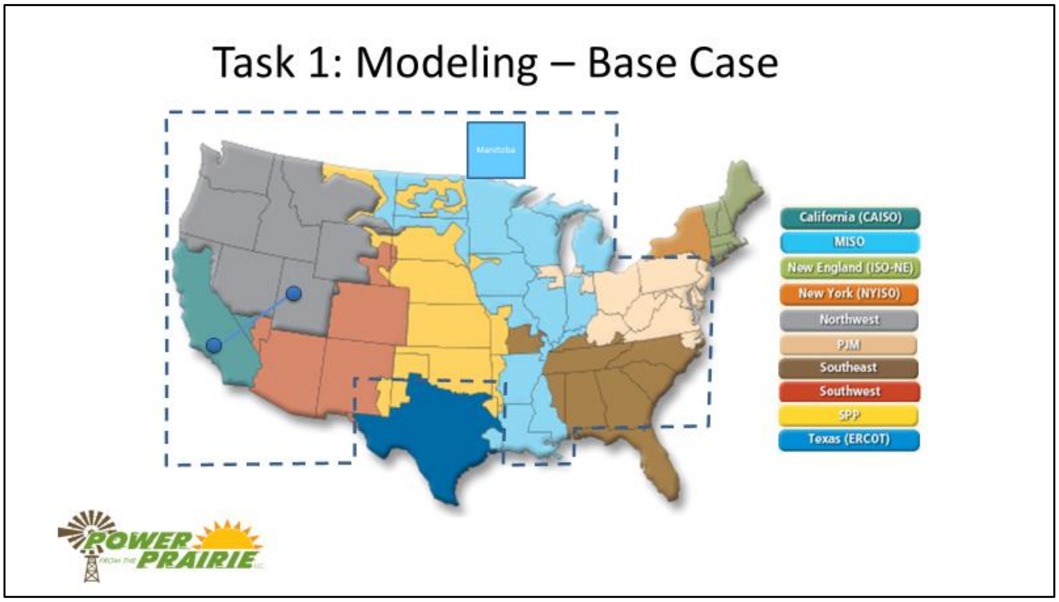
[28] Similar to the Multi-Value Project (MVP) cost recovery process for transmission in MISO.
[29] S.1016 (Heinrich) "Electric Power Infrastructure Improvement Act'', and corresponding elements of the Build Back Better Act.

Southwest Power Pool (SPP), Midcontinent System Operator (MISO) and PJM Interconnection (PJM) systems including all then-current legacy and currently planned generation and transmission resources (Figure V-1). See Exhibit V-6D for a summary of all modeling data sources and adjustments.

FIGURE V-1. The Base Case (Dashed lines indicate the span of the Gridview production cost model used in the CDS.)



Considering the leadtime it would take to permit and construct a PftP transmission line, the study examined the economics in a future year, 2030, for which utility planning model datasets were available. PftP LLC subcontractor team member Hitachi Energy (Hitachi) created the Base Case using the standard PROMOD production cost model datasets developed by MISO for such studies. The MISO dataset also included the corresponding data for SPP and PJM.

These MISO PROMOD datasets (MISO MTEP21 2030, Future 1) were converted to Gridview datasets for purposes of the study. Both PROMOD and Gridview are security-constrained production cost models. [30] Gridview was used because WECC uses Gridview, and Hitachi, the purveyor of both models, advised that PROMOD could not accommodate a dataset of the size needed for the CDS. Plus, Gridview does a better job of modeling energy storage.

[30] "Security constrained" means the production cost model knows and recognizes the configuration and limitations of the transmission system.

Hitachi conducted a benchmarking process to ensure the conversion of MISO dataset to Gridview adequately reflected similar results when run in PROMOD. See Exhibit V-1 for details.

Hitachi also used the Gridview model dataset of WECC (WECC Anchor Data Set (ADS) 2032 Version 1.0 beta). The planning organizations develop such planning models looking forward to future years.

Hitachi then joined the MISO and WECC datasets together to represent the geographic span of the study. Such organizations do not typically coordinate their planning years of load and renewables data assumptions. So, the datasets had to then be adjusted to ensure the correct hourly time relationships of loads and renewables to properly capture time diversity effects between renewables and use consistent assumptions for time zones and fuel prices. And the datasets had to be further refined to "carve-out" and define several of the utility CDS Participants in order to identify effects on them directly.[31] To the Study Team's knowledge, this is the first time such detailed, interregional utility data sets were combined and coordinated together to enable results down to the individual utility level. It was a major effort.

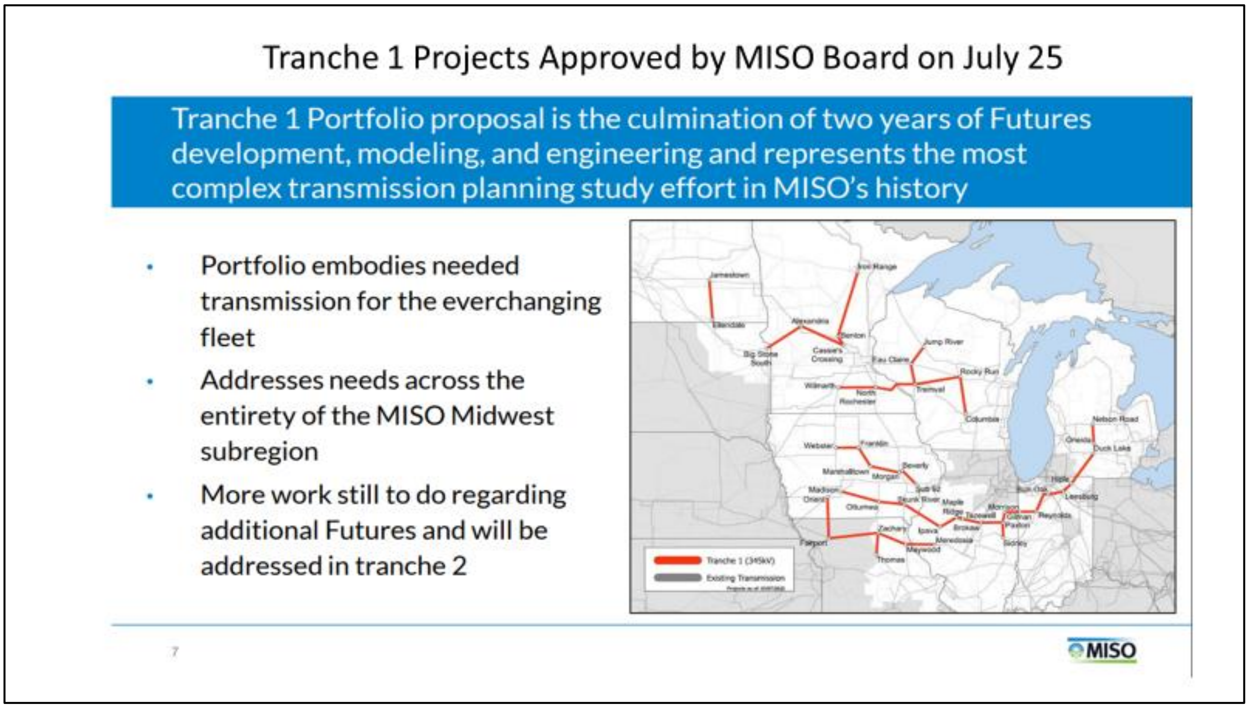
For example, to reconcile the two separately-developed datasets of MISO and WECC for Study Year 2030, Hitachi converted the wind, solar and load hourly shapes to the common 2018 reference year. This was necessary to achieve consistent load and weather patterns and appropriate time diversity effects across the span of the study. Peak loads and energy forecasts were also adjusted to a common year, 2030. Fuel and emissions prices were also adjusted to reflect the Year 2030, still recognizing regional differences.

Further, the production costing models of WECC and the RTOs are based on transmission load flow data for transmission studies. Such studies often typically focus on individual transmission elements, their loadings, and limitations. They do not always define utility service territories. So, Hitachi had to "carve out" some of the CDS participants resources in the datasets and assign them to the utilities to track production costs by individual utility. This again was a significant effort.

In the summer of 2022 and while the CDS was underway, the MISO Board approved the implementation of their Long-Range Transmission Plan (LRTP) "Tranche 1" transmission projects (Figure V-2). This $10.4B effort will further improve reliability and renewables interconnection in the MISO-North (or "Classic") region.

[31] RTO datasets are commonly developed for transmission power flow studies, which focus on individual transmission system components (i.e., breakers and transformers); not on the utilities that own them.

FIGURE V-2. The MISO LRTP "Tranche 1" Transmission Projects



These Tranche 1 projects were also added to the Base Case.

Hitachi also reviewed the resulting datasets with the planning staffs of the CDS Participants to ensure their familiarity with the assumptions being used for them. And to enable the Participants to further update the data with any changes in assumptions they wanted including retirements and additions.[32] This was done to support credibility of the modeling results when reported at an individual Participant level. Among other additions, CDS Participant MidAmerican Energy added their planned 2000 MW "Wind PRIME" project in Iowa to the Base Case.

2. Modeling Results

Modeling for the Base Case and all other Scenarios in the CDS used locational marginal pricing (LMP) for all loads and generation resources. The modeling was done on a nodal level down to individual transmission busses, with the CDS Participants identified as individual utilities. The modeling results for the Base Case are summarized for all RTOs

[32] This review was done with only those individuals at each Participant who had necessary Non-Disclosure Agreements and Critical Energy Infrastructure Information (CEII) certificates to ensure security of such sensitive information. This was another time-consuming complexity of the study.

and Planning Regions at Exhibit V-3A.[33] Overall, the Base Case model included approximately 110,000 transmission busses and about 19,000 generating units. Using Mixed-Integer Optimization (MIO), it took about 130 hours per case-year to run.

The total Adjusted Production Cost (APC) of all resources, calculated as (fuel cost + purchase cost – sales revenue) of the Base Case across the entire model was more than $67 Billion per year.

3. Economic Analysis

The Base Case was then used for comparison to the various PftP Scenarios in the economic analyses. See Exhibit V-6 for summaries of input assumptions used in the analysis.

Conservative Benefit/Cost Ratios

With regard to comparisons of benefits and costs between the Base Case and various Scenarios, it is recognized that Benefit/Cost ratios calculated in the CDS using production cost benefits alone are conservative (I.e., low). In fact, transmission studies performed by MISO indicate that production cost savings may represent only a portion of the total benefit, when all potential transmission benefits are considered (Figure V-3).

FIGURE V-3. Production Cost and Total Benefits for Transmission[34]

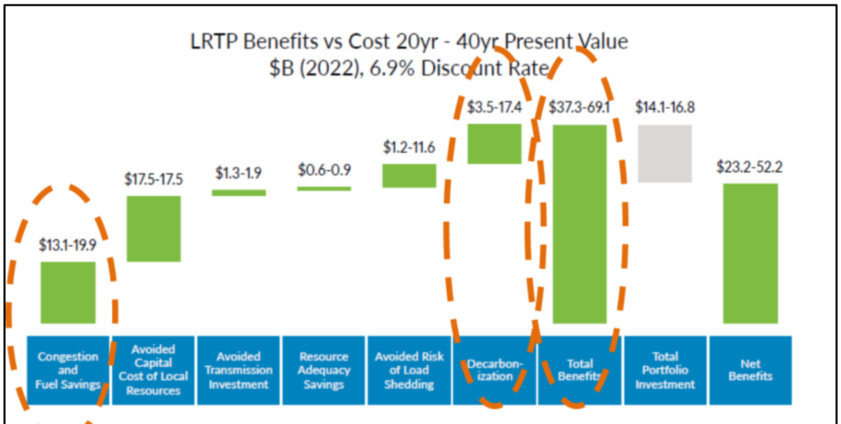


Figure 2: LRTP Tranche 1 Portfolio benefits far outweigh costs (Values as of 6/1/22)*

*Note: This implies benefit-to-cost (B/C) ratio ranges of 20-yr PV B/C = 2.6 and 40-yr PV B/C = 4.0

[33] Modeling results by CDS Participant are confidential to each Participant and are included in non-public, individual reports for each Participant.
[34] "MTEP21 Report Addendum; Long Range Transmission Planning Tranche 1", Executive Summary, Midcontinent Independent System Operator (MISO), June 1, 2022, at Figure 2 at Page 3.

As an illustration, in this MISO Long Range Transmission Plan (LRTP) study for their Tranche 1 transmission projects that were included in the CDS Base Case, production cost and decarbonization benefits were found to be only about half the total benefit when all benefits were considered.[35]

This MISO result is only an example. HVDC transmission benefits may be different than HVAC benefits. But using these MISO results as an indicator for PftP, this means that when the additional benefits of PftP are determined in Stage 2, *they may materially increase the benefit/cost ratios calculated in this CDS* using production cost and decarbonization benefits alone.

4. Observations

a. A significant portion of the $800k total cost of the CDS was devoted to creating the Base Case model as described above. Now that that work is done, the Base Case can be used for multiple similar analyses across a major portion of the Western and Eastern Interconnections.

b. For future interregional studies, FERC should provide guidance to the planning authorities that they should adopt common study years and assumptions to better facilitate such studies.

B. SCENARIO A: ADD TRANSWEST AND SOO GREEN HVDC LINES

1. Definition

This Scenario added the proposed TransWest Express and Soo Green HVDC lines to the Base Case (Figure V-4). These proposed projects, already in advanced stages, are key to the implementation of an overall interregional approach for PftP.

- TransWest Express (www.transwestexpress.net) is a new, 3,000 MW, 500 kV HVDC line proposed by the Anschutz Group. It will originate at the Sinclair Substation in Wyoming and span to the Intermountain Power Plant (IPP) site near Delta, Wyoming. There, Transwest envisions that a portion of its output would continue Southward on the existing Southern Transmission System (STS) HVDC line to Southern California. The balance of TransWest flow would travel on a new, TransWest 500 kVAC line from the IPP site to Southern Nevada.
    - A TransWest affiliate, Wyoming Power Company, would install 3,300 MW of new wind resources in Wyoming. This renewable energy would be carried on the TransWest HVDC line. Thus, the TransWest line will directly enable this additional

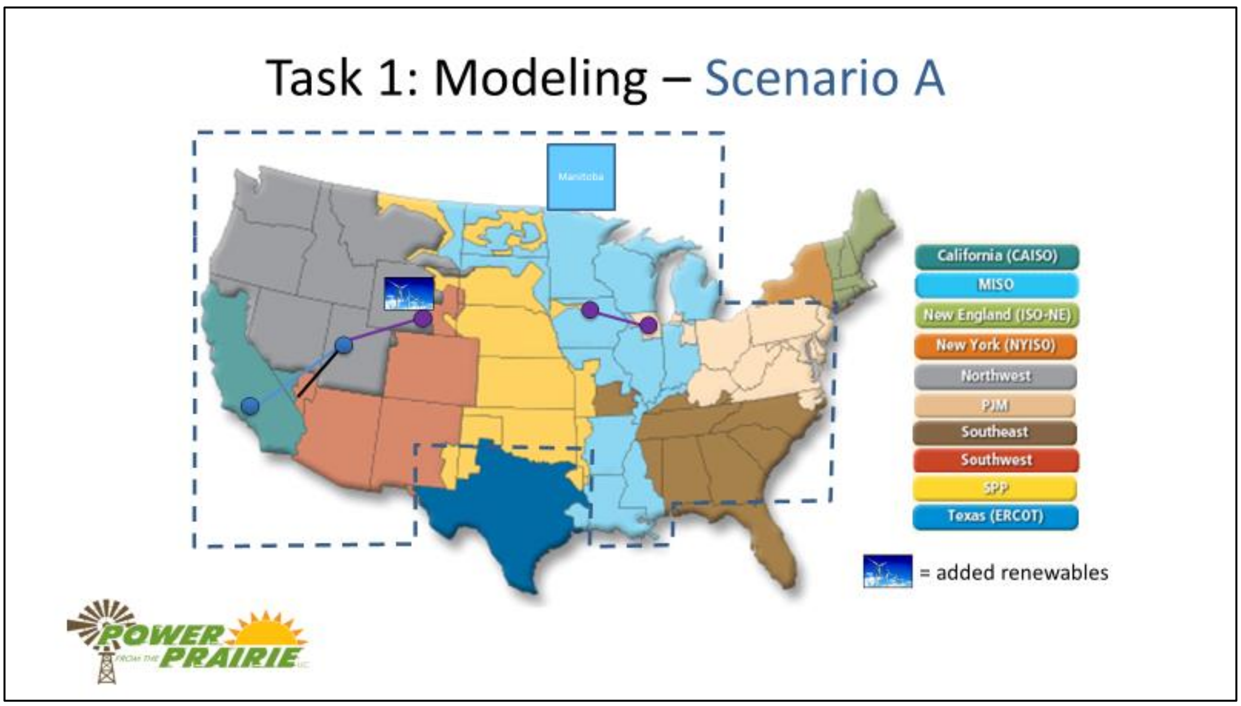
[35] The CDS used MISO's production cost model dataset, and carbon emissions similar to what MISO used in their LRTP. In the CDS, decarbonization benefits were both included in production cost benefits while in Figure V-3 MISO apparently calculated these two benefits separately.

renewable resource to get to markets. These new renewables were not assigned to a particular utility off-taker, but were allowed to affect LMP market prices.

- Soo Green (https://soogreen.com) is a new, 2,100 MW, 525 kV HVDC line proposed by Direct Connect that would originate in MISO at the Killdeer Substation near Mason City, Iowa and span to the Plano Substation in PJM near Chicago.
  - A unique feature of this line is that it would be underground, installed in a railroad right of way. This approach, while its contruction cost is more expensive than overhead, has signficant routing and permitting advantages.
  - The Soo Green line does not directly enable the installation of additional renewable resources, although it would improve the market opportunities and hopefully pricing for existing renewables.

  In the initial modeling, Hitachi noticed significant congestion around the Western Terminal of Soo Green at the Killdeer substation in MISO near Mason City, IA. Additional 345 kV interconnections were added to the model to reduce this congestion to more acceptable levels.[36]

FIGURE V-4. Scenario A



[36] These are MISO AC interconnections to Soo Green. MISO is completing a study of the needed interconnections, but the results are not released at the time this CDS Report went to press. So, the CDS Team created assumptions for them for purposes of the CDS.

2. Modeling Results

The production cost modeling results for Scenario A are shown at Exhibit V-3B for all RTOs and Planning Regions. The Scenario shows significant production benefits compared to the Base Case:

- A reduction in total Adjusted Production Costs across all regions of about $790 million in Year 2030. (Exhibit V-3B)
  - About $717 million of this savings happened in WECC.
  - The balance ($73 million) happened in non-WECC areas (i.e., the Eastern Interconnection).
- A reduction in carbon emissions of about 5.7 million metric tons per year (Exhibit V-3B)
- An increase in renewable generation of 12.8 million MWh.
  - Largely attributable to the new Wyoming Power Company (WPC) renewables added with TransWest Express. (Exhibit V-3B)
- A net 0.1% increase in total wind and solar curtailment. (Exhibit V-3B)
  - This increase was attributable to a 2% increase in total wind and solar generation from the TransWest WPC addition. That is, there were more installed MW of wind subject to curtailment.
- Average annual LMPs decreased 2.4% in WECC due to the additional TransWest renewables. In CAISO they decreased 4%, and in the Los Angeles Department of Water & Power (LADWP) balancing area by 9%. (Exhibit V-8A)
- Annual transmission line capacity factors (C.F.):[37]
  - Soo Green line:
    - West-to-East flow on the Soo Green HVDC line was 14.7 million MWh at 2100 MW (C.F. of 80%)
    - East-to-West flow was 95,000 MWh at 2100 MW (C.F. of 0.6%).
  - TransWest DC line:
    - North-to-South flow was 20.2 million MWh (C.F. of 74%).
    - South-to-North flow was 284,000 MWh (C.F. of 2%).
  - STS line:
    - Flow from North-to-South (Utah to California) goes from 3.3 million MWh (C.F. of 18%) in the Base Case to 10.8 million MWh (C.F. of 51%) in Scenario A. A 230% increase.
    - Flow from South-to-North (California to Utah) goes from 780,000 MWh (C.F. of 6%) in the Base Case to 86,300 MWh (C.F of 0.7%) in Scenario A.

[37] The term "capacity factor" is a measure of how much the line is loaded throughout the time period. It compares the energy the line carried during that period with the maximum it could have carried if it had operated at full capacity during the entire time period. A 100% C.F. means the line was fully loaded to its capacity in all hours.

3. Economic Analysis

Cost assumptions and the economic analysis for Scenario A compared to the Base Case are provided at Exhibits V-7A to V-7H. Financial assumptions for the economic analysis are provided at Exhibit V-6.

4. Observations

- Flows on the TransWest and Soo Green HVDC lines without PftP are both primarily unidirectional. (Exhibits V-5A and V-5C, respectively).
  - For example, TransWest North-to-South and South-to-North capacity factors were 74% and 2%, respectively.
    - Primarily delivery of Wyoming wind to Southwestern loads.
    - There is relatively little load in Wyoming for Southwestern generation to serve.
  - Soo Green West-to-East and East-to-West capacity factors were 80% and 0.6%, respectively.
    - PJM loads apparently desire MISO generation more than vice versa.

- The total APC benefit of Scenario A to all RTOs and planning areas is significantly larger than the total APC benefit seen by the CDS Participants alone. (Exhibits V-3B and V-4B (Confidential), respectively).
  - This shows a lot of CDS non-Participants would be also benefitting from Scenario A, even if they did not participate in owning it.

- The TransWest Express HVDC line project with its affiliated new renewables it enables[38] and without PftP:
  - Has a TRP benefit/cost ratio[39] of 0.98, using investor-owned facility financing which is appropriate for such merchant facilities. (Exhibit V-7A).
    - If the proposed federal ITC for transmission passes, this benefit/cost ratio increases further to 1.15.
    - For comparison, the same facilities using public power financing would have a TRP benefit/cost ratio of 1.63.[40] (Exhibit V-7C). With the proposed ITC for transmission passes, this ratio would increase to 1.85.[41]

[38] The term "enables" means the project facilitates installation of additional renewables that would not be possible without the project.

[39] A benefit/cost ratio of 1.0 means the project's benefits equal its costs while fulfilling the owner's financial requirements. A ratio greater than 1.0 means the benefits exceed the costs, implying the project would be beneficial to consumers' rates. A ratio less than 1.0 means the costs exceed the benefits, implying the project would tend to increase consumers' rates.

[40] Although not applicable to TransWest as a merchant, the public power benefit/cost ratio is shown here to illustrate that, for projects with multi-billion-dollar capital costs as examined in this study, the project financing matters to the benefit/cost ratio.

[41] Assuming public power would be eligible for such benefits, as they are for renewables and solar in the IRA.

- Much of the benefit can be attributed to the presence of the additional renewables.

TABLE V-1

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

- Reduces total carbon emissions by 4.8 million metric tons/year.

- The Soo Green HVDC project without enabling new renewables and without PftP:
  - Has a TRP benefit/cost ratio of 0.19 using investor-owned financing which is appropriate for such merchant facilities. (Exhibit V-7E).
    - If the proposed federal ITC for transmission passes, this investor-owned benefit/cost ratio increases to 0.27.
    - For comparison, the same facilities using public power financing without the ITC would still have a TRP benefit/cost ratio of 0.33, increasing to 0.57 with the ITC. (Exhibit V-7G)

TABLE V-2

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

  - The relatively low benefit/cost ratios are attributable to the fact that:
    - The project does not *enable* additional new renewables like TransWest Express does. While the project provides additional market opportunities and price arbitrage for existing renewables, those are relatively smaller impacts.

- The modest benefit/cost ratios calculated here represent a utility point of view of the project.
  - Soo Green could still be a viable project assuming they secure a shipper of generation who wants to move their product to a buyer. If the shipper is a

renewables developer or owner, Soo Green may “enable” those renewables to get to market.

- The Soo Green project at 2,100 MW reduces total carbon emissions by 909,000 metric tons/year. (Exhibit V-3B).

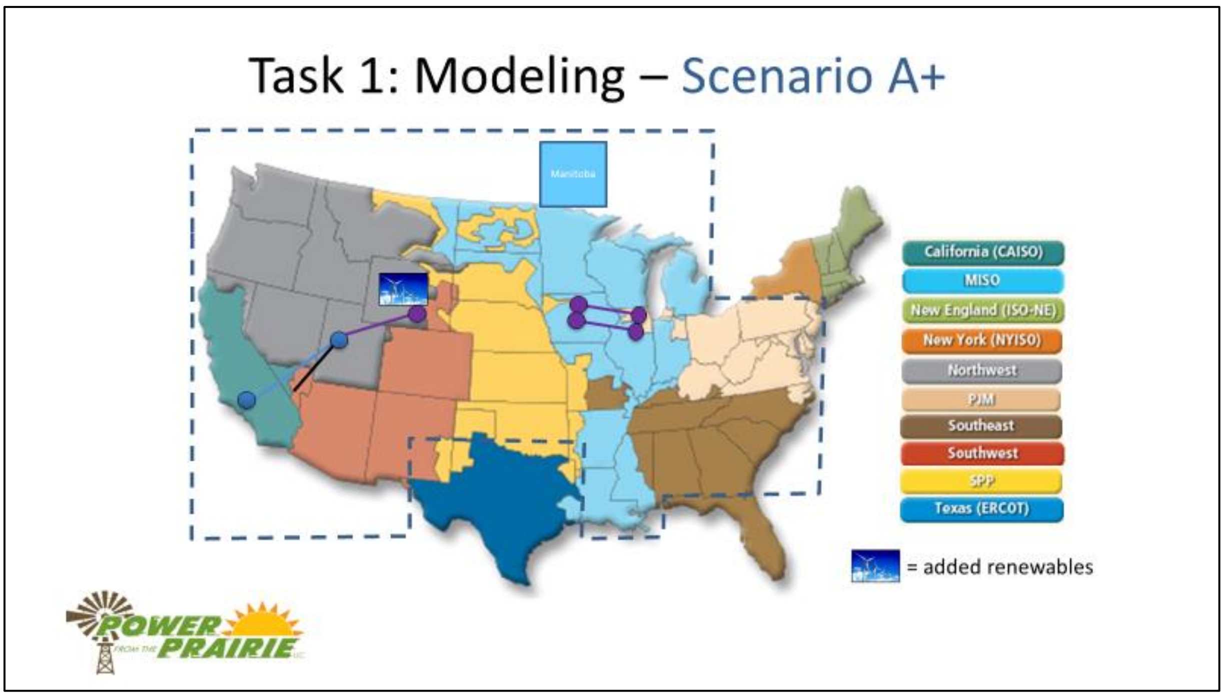
C. SCENARIO A+: DOUBLE SOO GREEN

1. Definition

This Scenario A+ was designed to be a sensitivity case on Scenario A. Because the PftP line is rated at 4000 MW, and Soo Green project is planned at 2100 MW, Scenario A+ would install an additional, twin, 2100 MW HVDC line alongside Soo Green. (Figure V-5). This is intended to enable the full 4000 MW of PftP to get to Chicago, when PftP is added later in Scenario B.

All other assumptions in Scenario A remained the same in Scenario A+. Like Scenario A, Scenario A+ did not have PftP installed yet.

FIGURE V-5. Scenario A+



2. Modeling Results

The regional production cost modeling results for Scenario A+ are shown at Exhibit V-3C, summarized for all RTOs and Planning Regions. Increasing the capacity of the Iowa to Chicago connection shows incremental production and carbon emissions benefits compared to Scenario A:

- An incremental net reduction in total Adjusted Production Costs across all regions of about $15 million in Year 2030. (Exhibit V-3C)
  - Because the development happened in the Eastern Interconnection, most of the benefit occurred there, in MISO and SPP.
  - Small changes happened in WECC, apparently enabled across the existing AC/DC/AC ties between the interconnections.

- An incremental reduction in carbon emissions of about 72,000 metric tons (Exhibit V-3C).

3. Economic Analysis

Scenario A+ offered only modest incremental production cost benefits compared to Scenario A. And it would entail a very large capital cost to double the Soo Green line. Considering the financial and physical limitations already facing the Soo Green project at 2100 MW as seen from a utility perspective as described above, further efforts on Scenario A+ were abandoned.

4. Observations

- Increasing the size of the Iowa-to-Chicago HVDC transmission capacity without PftP installed provides incremental production and carbon emissions benefits. But it also adds additional costs for the second HVDC line.

- The increase in HVDC line capacity was assumed to not enable additional renewables, which would have provided additional benefits for the Scenario.

- Economics of Scenario A+ without PftP is incrementally better than Scenario A, but still is not cost-effective.

D. SCENARIO B: ADD POWER FROM THE PRAIRIE LINE

1. Definition

Scenario B adds the 4,000 MW Power from the Prairie HVDC line to Scenario A (Figure V-6). In addition, 3,000 MW of additional new generic renewable resources were added at the converter station in the middle of PftP (the Central SD/NE converter). The renewables were assumed to be a 30%/70% mix of solar and wind on an energy basis. Although there are no specific plans yet for these renewables, the modeling assumed that half would be located in Nebraska and half would be in South Dakota. These new renewables were not assigned to any specific CDS Participants but were allowed to affect market prices.

The purpose of this Scenario was to examine the performance, costs, and benefits of the PftP project with additional renewables when combined with the Scenario A facilities in an interregional configuration.

In the design of this Scenario, the CDS Participants were polled to determine the AC transmission interconnections they desired to connect to the various PftP HVDC converters. This was done to ensure the Participants would receive full value of the PftP line to their individual systems.

This process primarily involved connections to the PftP Central SD/NE converter that, unlike the other converter locations, would be "greenfield" because an AC substation is not already located there.[42] The configuration of these connections is shown at Exhibit V-2E1.

The addition of PftP provides both the TransWest and Soo Green projects the opportunity to be more fully bi-directional.

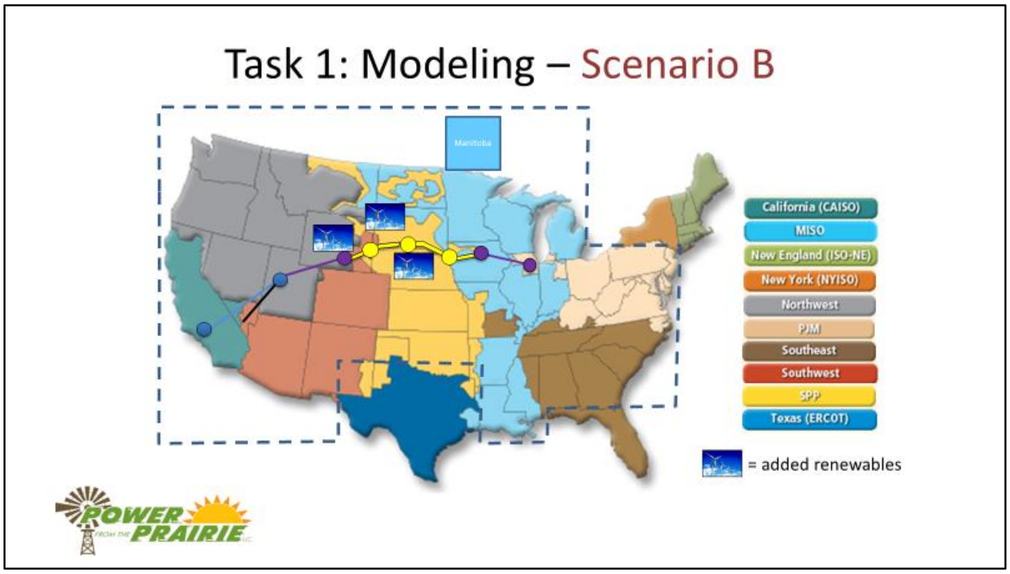
Unassigned Renewables

Importantly, none of the 3000 MW of additional renewables in this Scenario B were assigned to any particular entity. As such, the modeling calculated the total market value of these renewables that would be available to those entities who may decide to own or otherwise hold the rights to them.

This means the production costs calculated for each CDS Participant and detailed in Volume 3 of this Report for each CDS Participant understate the production cost benefits of PftP to each Participant, to the extent they could otherwise claim a portion of these unassigned renewables and their associated production cost benefits for themselves.

[42] See the Task 2A (Section VI) discussion for definition of the PftP HVDC converter locations.

FIGURE V-6. Scenario B



2. Modeling Results

The modeling results for Scenario B are shown at Exhibit V-3D for all RTOs and Planning Regions.

3. Economic Analysis

Cost assumptions and the economic analysis for Scenario B compared to Scenario A are provided at Exhibits V-7I to V-7L for both the TRP and RTO Perspectives. Financial assumptions for the economic analysis are provided at Exhibit V-6.

4. Observations

- A reduction in total Adjusted Production Costs across all regions of about $816 million in Year 2030 compared to Scenario A. (Exhibit V-3D)
- Most of these savings happened in WECC.
  - The balance happened in non-WECC areas (i.e., the Eastern Interconnection).
- The PftP HVDC line project with the affiliated new renewables it enables:
  - Has a TRP benefit/cost ratio of 1.15 using public power financing. (Exhibit V-7K)

    - The proposed 30% federal income tax credit for HVDC and HVAC transmission facilities similar to that provided to renewables and storage in the Inflation Reduction Act, if enacted, would increase this benefit/cost ratio to 1.44.[43]
  - Has a TRP benefit/cost ratio of 0.63 using investor-owned financing. (Exhibit V-7I)
    - The proposed 30% federal income tax credit for HVDC and HVAC transmission facilities similar to that provided to renewables and storage in the Inflation Reduction Act, if enacted, would increase this benefit/cost ratio to 0.82.

TABLE V-3[44]

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

- An incremental reduction in carbon emissions of an additional 7.3 million metric tons per year compared to Scenario A. (Exhibit V-3D)

- An increase in renewable generation of 11.9 million MWh. (Exhibit V-3D)
  - Attributable to the 3,000 MW (8.9 million MWh) of additional new generic renewables added with the PftP line, and reduced curtailment of existing renewables made possible by the addition of the PftP line.

- A reduction in wind and solar curtailment of 3.0 million MWh (or 12%). (Exhibit V-3D)
  - Most of this decrease was probably attributable to PftP providing additional markets for existing renewables to serve. Even though there were more total renewables installed due to the PftP project additions.

- Average annual LMPs *increased* in WECC by 5%, ranging from 5% to 6% in both CAISO and LADWP. (Exhibit V-8A)
  - Total hours of negative LMPs declined in both CAISO and LADWP. (Exhibits V-8B and V-8C)

[43] Assuming public power would be eligible for such benefits for transmission, as the IRA offers them for renewables and storage.

[44] In the RTO Perspective, some but not all public power entities have hypothetical capital structures used in their RTO cost recovery. These hypothetical capital structures, which make the public power entity's transmission fixed costs similar to an investor-owned entity, were approved by FERC to represent the fact that public power is subject to the same risks in a transmission project that investor-owned utilities face. While the hypothetical structure benefits the public power entity in transmission cost recovery, it increases their fixed costs in the RTO Perspective, and thus decreases their RTOP benefit/cost ratio.

  - Again, this was probably the effect of PftP providing additional markets to the North and East for California renewables to serve, reducing hourly over-generation compared to their local load.

- With one exception, an increase in most of the existing HVDC transmission line capacity factors compared to Scenario A (Exhibits V-5):
  - TransWest DC line:
    - North-to-South increases from 74% in Scenario A to 81% in Scenario B.
    - South-to-North increases from 2% in Scenario A to 5% in Scenario B.
  - Soo Green line (2100 MW):
    - West-to-East flow declines from 80% in Scenario A to 75% in Scenario B.
      - The PftP line provides additional markets to the West for generation in MISO; thereby diverting flows that would otherwise go East on Soo Green.
    - East-to-West flow, which is relatively small, increases from 0.6% in Scenario A to 1.5% in Scenario B. Again, due to the effect of PftP providing access to additional new markets in the West.
  - STS line:
    - North-to-South increases from 51% in Scenario A to 55% in Scenario B.
    - South-to-North flow increases from 1% in Scenario A to 5% in Scenario B.

- As an illustration of effects on existing non-renewable generation, the annual capacity factor of the IPP CCGT plant in Utah (to be installed in 2025) declines further from 58% in the Base Case, to 44% in Scenario A, to 36% in Scenario B.
  - It's operation significantly affected by additional renewables coming from both Wyoming in Scenario A, and now Central South Dakota and Nebraska in Scenario B.
  -
- Performance of the five PftP HVDC converters (flows into and out of the AC systems at each location) is shown on Exhibit V-5J.

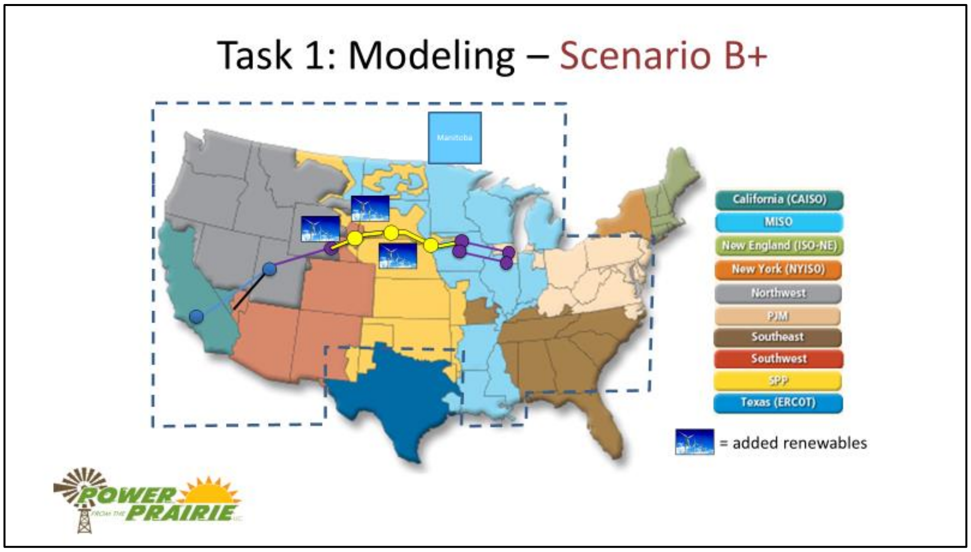
E. SCENARIO B+: DOUBLE SOO GREEN

1. Definition

Similar to Scenario A+, Scenario B+ was a sensitivity analysis. Like Scenario A+, this Scenario doubles the Soo Green line capacity between Mason City and Plano, Illinois (Figure V-7). This increases the total Soo Green capacity to more than 4,000 MW, to ideally better match-up with the 4,000 MW PftP line added in Scenario B.

Again, no additional renewables were added in this Scenario B+.

FIGURE V-7. Scenario B+



2. Modeling Results

The regional production cost modeling results for Scenario B+ are shown at Exhibit V-3E, summarized for all RTOs and Planning Regions. Increasing the capacity of the Iowa to Chicago connection shows incremental production and carbon emissions benefits compared to Scenario B:

- An incremental net reduction in total Adjusted Production Costs across all regions of about $39 million in Year 2030, compared to Scenario B. (Exhibit V-3E)
  - Because the development happened in the Eastern Interconnection, most of the benefit occurred there, in MISO and SPP.
  - Small changes happened in WECC, apparently enabled across the existing AC/DC/AC ties between the interconnections.

- An incremental reduction in annual carbon emissions of about 724,000 metric tons (Exhibit V-3E).

3. Economic Analysis

Like Scenario A+, this Scenario B+ offered only modest incremental production cost benefits compared to Scenario B. And it would entail a very large capital cost to double the Soo Green line. Considering the financial and physical limitations already facing the Soo Green project at 2100 MW as seen from a utility perspective as described above, further efforts on Scenario B+ were also abandoned.

F. SCENARIO C: ADD GREGORY COUNTY PUMPED STORAGE

1. Definition

This Scenario C adds the Gregory County Pumped Storage Project (GCPSP) to the Power from the Prairie line (Scenario B). See Figure V-8. The purpose of this Scenario was to examine the performance, costs, and benefits of the GCPSP project including additional renewables it enables when combined with PftP HVDC transmission and the access it would provide to new markets to the West and Eat.

GCPSP is a proposed 1,800 MW (pumping and generation) facility with 46 hours of storage duration. It is a located on a site in Central South Dakota identified decades ago by the U.S. Corps of Engineers as the best location for pumped storage on the Missouri River. The lower reservoir would be Lake Francis Case, the 5.3 million acre-feet impoundment behind the Fort Randall dam. The upper reservoir would be man-made, with 700 feet of head.

CDS Participant MRES holds the FERC Preliminary Permit for the project. Together with another CDS Participant, MidAmerican Energy (MEC), as the GCPSP project owners they are actively working toward a full license application for the project (FERC Project # P-14876-002).

The project would not only further benefit the additional 3,000 MW of generic new renewables installed with the PftP line in Scenario B, but it would also represent a new market for other existing renewables to its East and West. Economic dispatch of the entire GCPSP facility in the CDS was based on LMPs at the GCPSP site. Eventually, the dispatch might be based on LMPs at multiple locations on the HVDC system. That is, with interregional access using PftP, GCPSP could take advantage of multiple LMP options to decide whether to pump or generate in any particular hour.

663 MW of the 1800 MW of new generic renewables installed in Scenario C, and 180 MW (10%) of the GCPSP capacity was assigned to MRES in Scenario C for purposes of the GridView modeling. Previous Loss of Load Expectation (LOLE) analysis by the Study Team for MRES determined this swap of storage and renewables, plus other peaking capacity resources to be identified later,[45] would provide reliability equal to or better than legacy facilities that may eventually be retired.

In addition to the 3000 MW of new generic renewables added in Scenario B (all of which remained unassigned to owners(s)), Scenario C added an additional 1800 MW of new, generic renewables (a 30%/70% solar/wind mix based on energy) at the Central SD/NE converter which was assumed to be located at or near the GCPSP site. These renewables would be placed electrically behind GCPSP as viewed by the PftP line. In

[45] Potentially including other, shorter leadtime supplemental resources like batteries.

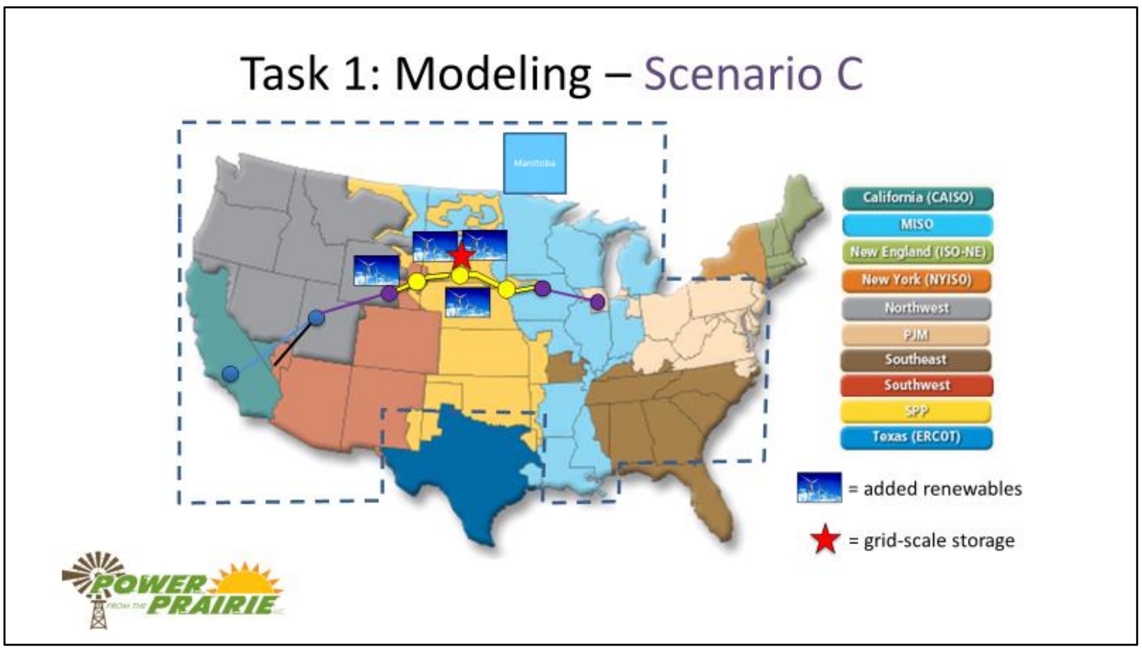
this manner, the 1800 MW GCPS could enable the additional renewables by acting as a transmission asset.

Unassigned Renewables

None of the generic new renewables added with GCPSP were assigned to MEC. So, like Scenarios B, D, and E, this Scenario also had a quantity of unassigned renewables. No retirement of legacy generation was assumed for MEC.

The pumping and generation capacity and energy of the GCPSP facility itself was assigned to its owners (CDS Participants MRES and MEC) for purposes of the production cost modeling.

FIGURE V-8. Scenario C



2. Modeling Results

The modeling results for Scenario C are shown at Exhibit V-3F for all RTOs and Planning Regions.

3. Economic Analysis

Cost assumptions and the economic analysis for Scenario C are confidential to the GCPSP owners, who are CDS Participants. Financial assumptions for the economic analysis are provided at Exhibit V-6.

4. Observations

- Total Adjusted Production Costs across all the CDS Participants decline by about [CONFIDENTIAL] million in Year 2030[46] compared to Scenario B.
  - Recall that a portion of the generic new renewables installed with GCPSP were assigned to MRES and thereby benefited MRES production costs. None of the additional renewables were assigned to MEC.

- GCPSP with the associated new renewables it enables, when added to PftP:
  - Has a TRP benefit/cost ratio of [CONFIDENTIAL] using investor-owned financing.
    - If the IRA federal income tax credit of 30% on energy storage facilities would apply to GCPSP, that would make this benefit/cost ratio [CONFIDENTIAL].[47]
  - Has a benefit/cost ratio of [CONFIDENTIAL] using public power financing.
    - If the IRA federal income tax credit of 30% on energy storage facilities would apply to GCPSP, that would make this benefit/cost ratio [CONFIDENTIAL].[48]
  - Reduces carbon emissions by a net 1.7 million metric tons per year compared to Scenario B.
    - Results from a 4.5 million ton reduction in MISO and SPP where the project is located, partially offset by increases in PJM and WECC.

G. SCENARIO D: THE MINNESOTA POWER HVDC CONNECTION

1. Definition

This Scenario D ("The MP Connection") was designed to examine various options for CDS Participant Minnesota Power (MP). It started with Scenario B that included the PftP line. The purpose of this Scenario was to examine the performance, costs, and benefits of increasing the capacity of an existing MP HVDC line and increasing the renewables enabled by it, in combination with the PftP interregional transmission project.

MP owns 500 MW of wind energy resources in North Dakota, connected to Duluth, MN by an existing +/- 250 kV for a total of 500 kV, 500 MW HVDC line. They also have major transmission connections to Manitoba Hydro in Canada (Figure V-9).

For Scenario D, the following was assumed for the MP Connection:

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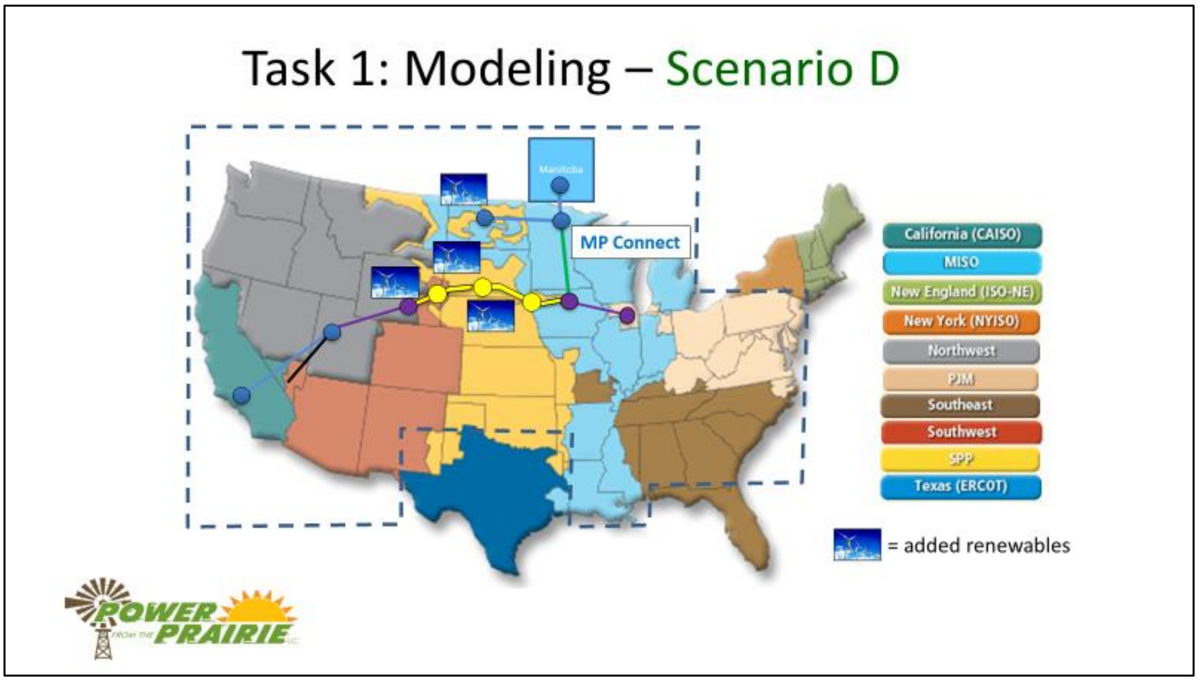
[46] GCPSP Owners MRES an MEC are CDS Participants. The economic results for the project are confidential and provided in the non-Public Volume 3 of this Report.
[47] For comparison, the recently passed federal Inflation Reduction Act (IRA) offers a 30% ITC to energy storage projects, regardless of whether they enable additional renewables like GCPSP would do.
[48] Assuming public power would be eligible for this benefit for GCPSP, like the IRA offers to them for renewables and storage.

a. Increasing the capacity of the existing MP Square Butte-to-Arrowhead HVDC line from 500 MW to 3,000 MW.[49]
b. Increasing the existing 500 MW of wind in North Dakota by an additional 2,500 MW of renewables. Like Scenario B and C, the additional renewables would be 30% solar/70% wind on an energy basis (or 1.75/2.00 wind/solar mix on a capacity basis). These additional renewables would not be assigned directly to MP's generation fleet, but instead would be available on the market.
   i. As a result, the enhanced HVDC line would be enabling the additional 2,500 MW of renewables in North Dakota.
c. Adding an AC connection from MP to the PftP Mason City converter at the Killdeer substation at Mason City, IA. This and other AC lines in the region would provide a direct MP Connection from MP to PftP.

FIGURE V-9. Scenario D



2. Modeling Results

The modeling results for Scenario D are shown at Exhibit V-3G for all RTOs and Planning Regions.

[49] This HVDC line runs from Square Butte in North Dakota to Arrowhead substation near Duluth. At the time of this Report, Minnesota Power's parent company, Allete, announced plans for another 3,000 MW HVDC project to run from Square Butte westward to also cross the Western/Eastern Interconnections seam.

Unassigned Renewables

Importantly, similar to Scenario B, none of the 2500 MW of additional renewables in this Scenario D were assigned to any particular entity. As such, the modeling calculated the total market value of these renewables that would be available to those entities who may decide to own or otherwise hold the rights to them.

This means the production costs calculated for each CDS Participant and detailed in Volume 3 of this Report for each CDS Participant understate the production cost benefits of PftP to each Participant, to the extent they could otherwise claim a portion of these unassigned renewables and their associated production cost benefits for themselves.

3. Economic Analysis

Cost assumptions and the economic analysis for Scenario D compared to Scenario B are provided at Exhibits V-7O to V-7R for both the TRP and RTO Perspectives. Financial assumptions for the economic analysis are provided at Exhibit V-6.

4. Observations

- The Minnesota Power Connection improvements and the associated additional renewables they enable, when added to PftP (Scenario B):
  - Reduce regional production costs by $314 million. (Exhibit V-3G)
  - Have a benefit/cost ratio of 0.56 using investor-owned financing, which is appropriate for an IOU like MP. (Table V-4 and Exhibit V-7O)
    - The proposed 30% income tax credit for HVDC and HVAC transmission like that provided to renewables and storage in the IRA would make this benefit/cost ratio 0.76.[50]
  - For purposes of illustration, the corresponding TSP benefit/cost ratio using public power financial assumptions (without an ITC) would be 1.0. With the proposed ITC for transmission, 1.15.[51,52] (Exhibit V-7Q)
  - Have an RTOP benefit/cost ratio of 2.24 to 3.19, measured without or with a transmission ITC, respectively for public power without a hypothetical capital structure (Table V-4).
    - The corresponding benefit/cost ratio with a hypothetical capital structure is 1.10 to 1.56, again without or with an ITC, respectively.

[50] The recently passed federal Inflation Reduction Act (IRA) offers a 30% ITC to renewable and energy storage projects. A similar ITC was discussed for transmission (S.1016, Heinrich), but the provision was dropped from the final bill.
[51] Assuming public power would be eligible for this benefit, like the IRA offers for renewables and storage.
[52] The CDS modeling indicates that several public power entities in the area could benefit from the MP Connection, in addition to Minnesota Power.

TABLE V-4

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

- Reduces carbon emissions by an additional 4.2 million metric tons per year compared to Scenario B.
- Has a minimal effect on the energy flows of the TransWest, PftP and Soo Green HVDC projects.

H. SCENARIO E: ADD UTAH CAES

1. Definition

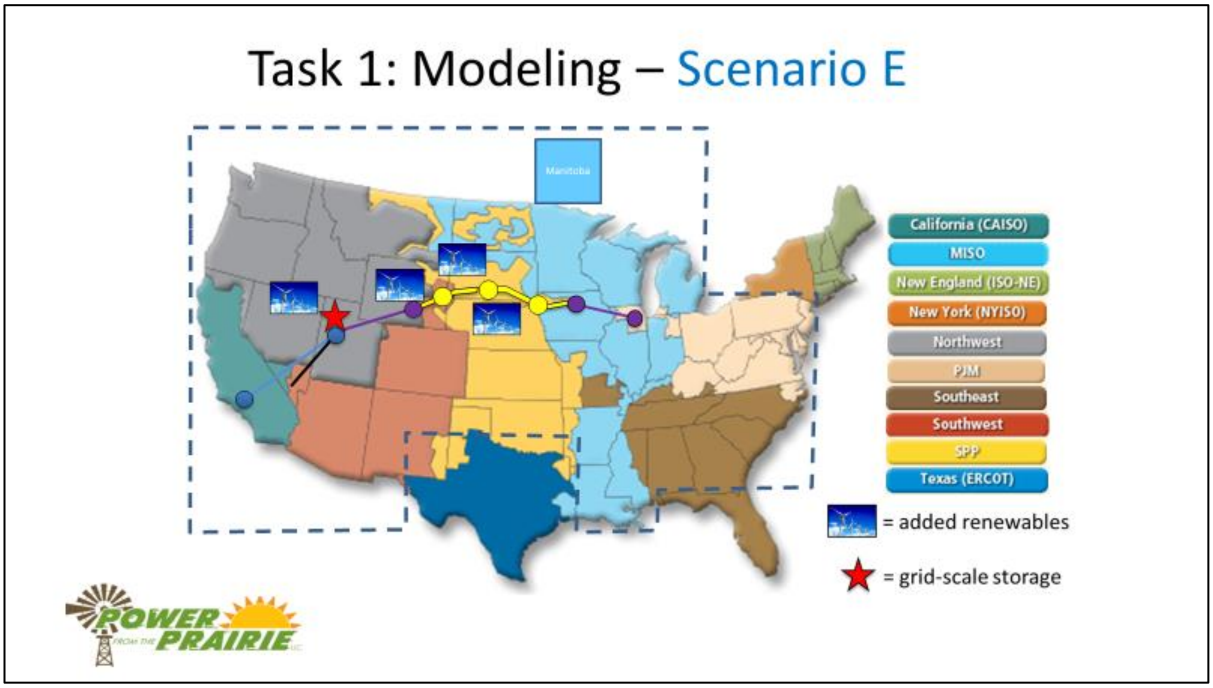
Scenarios E and E+ explore two additional options enabled by interregional HVDC, both located at the IPP site near Delta, Utah and both representing long duration energy storage. The first option, Scenario E, adds a 1,200 MW (pumping and generation) compressed air energy storage (CAES) facility with 48 hours of storage duration to Scenario B (Figure V-10).

Although CDS Participant SCPPA previously decided not to pursue a project like this in favor of other alternatives, the purpose of this Scenario was to examine the performance, costs, and benefits of CAES combined with additional renewables for consideration by other entities in WECC who may be interested. Also, with several pumped hydro storage projects currently being considered for sites in WECC, this Scenario provides baseline information to support comparisons of CAES with pumped hydro for similar long duration storage duties.

The IPP site features a unique, world-class salt deposit located immediately under the existing 1,800 MW IPP coal plant scheduled to be retired in 2025 and replaced with an 845 MW, natural gas-fired combined cycle gas turbine (CCGT) facility. This salt deposit can be used to brine mine underground caverns suitable for gas storage (compressed air, hydrogen, or other products).

The CAES facility was assumed to operate as a merchant plant, storing and generating market energy at LMP. An additional 1,200 MW of new generic renewables were assumed to be installed electrically behind the CAES facility, as viewed by the transmission system. In this manner, the CAES could be used as a transmission asset. Whenever the new renewables' output exceeds the transmission capacity, the CAES unit would pump to store the difference. Like the other Scenarios, the new renewables were assumed to have a 30%/70% solar/wind mix on an energy basis.

FIGURE V-10. Scenario E



2. Modeling Results

The modeling results for Scenario E are shown at Exhibit 3H for all RTOs and Planning Regions.

3. Economic Analysis

Cost assumptions and the economic analysis for Scenario E compared to Scenario B are provided at Exhibits V-7S to V-7V for both the TRP and RTO Perspectives. Financial assumptions for the economic analysis are provided at Exhibit V-6.

4. Observations

- Scenario E (add a compressed air energy storage (CAES) facility and 1,200 MW of additional renewables in Utah to Scenario B) results in an incremental total annual production cost reduction of about $177 million compared to Scenario B. (Exhibit V-3H)

- The addition of a merchant CAES facility in Utah to the HVDC system enabling 1,200 MW of additional renewables:

- Has a TRP benefit/cost ratio of 0.57 using investor-owned financing. (Exhibit V-7S)
  - Assuming the IRA federal income tax credit of 30% for energy storage applies to this project, that would make this benefit/cost ratio 0.69.[53]
- Has a TRP benefit/cost ratio of 0.67 using public power financing. (Exhibit V-7U)
  - Assuming the IRA federal income tax credit of 30% for energy storage applies to this project, that would make this benefit/cost ratio 0.80.

TABLE V-5

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

- Would reduce carbon emissions by 1.5 million metric tons per year.

I. SCENARIO E+: ADD UTAH HYDROGEN PRODUCTION

1. Definition

There is much discussion and excitement in the industry today about green (i.e., zero carbon) hydrogen. Much of the attention is focused on reducing the capital cost of electrolyzers to produce green hydrogen from water. Current technology can produce hydrogen at $5 to $6 per kilogram (kg). The goal is to reduce that cost to $1 to $2/kg.

The purpose of this Scenario is to provide baseline information regarding the challenge of achieving the hydrogen production cost goal using electricity from the grid.

In addition to the electrolyzer technology and cost challenge, PftP LLC believes another (and largely unrecognized) challenge is to achieve sufficiently constant clean energy to supply the electrolyzer to make the resulting hydrogen product truly green.[54] To achieve economic costs of green hydrogen, the capital-intensive electrolyzer needs to run at a high capacity factor (greater than 50%). And using only local renewables alone as a supply does not achieve that. For example, the local solar resource in Utah has an annual

[53] For comparison, the recently passed federal Inflation Reduction Act (IRA) offers a 30% ITC to energy storage projects, regardless of whether they enable additional renewables like Utah CAES is assumed to do.

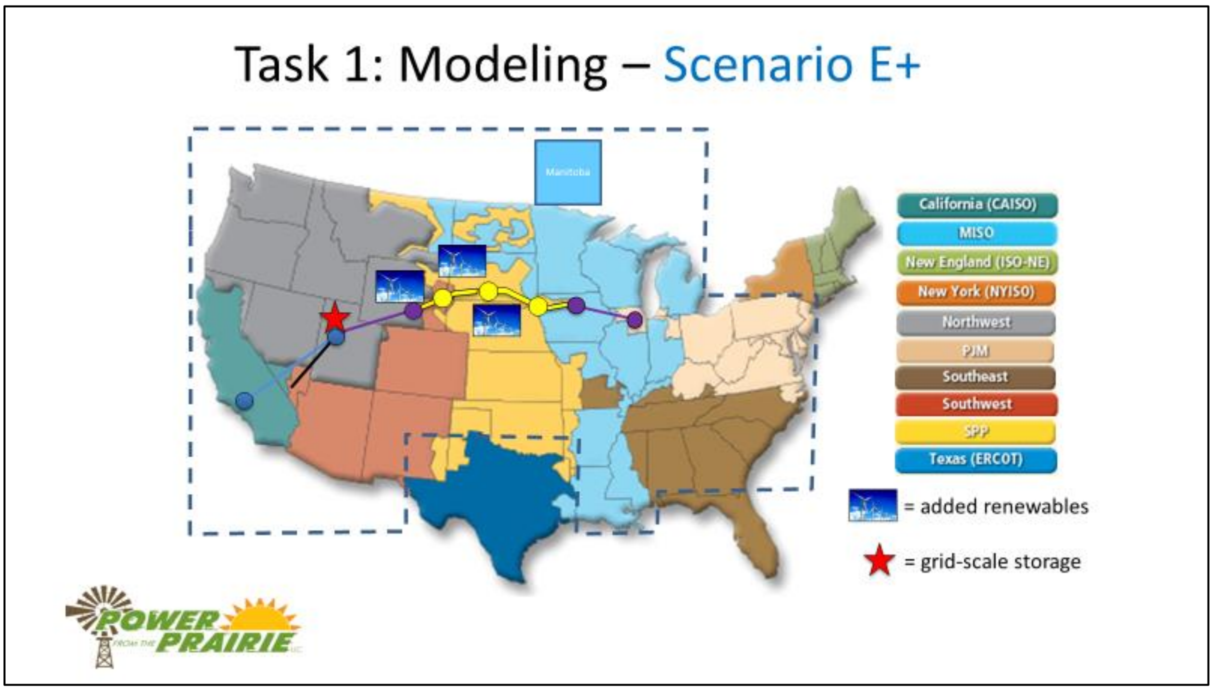
[54] R. Schulte and F. Fletcher, "Green Hydrogen and Electrolyzer Load Factor: The Elephant in the Room", *Power Engineering*. July 27, 2021, *available at:* www.powerfromtheprairie.com/publications.

capacity factor of only about 25%. And it has little or no time diversity with solar in Southern California.[55]

This second storage option in Utah, this Scenario E+, examines what the capital cost of a generic electrolyzer, operating as a merchant facility and dispatched into LMPs, would need to be to achieve a $2/kg price point. The Scenario assumes a 210 MW electroyzer load at the IPP site.[56] It was assumed to be added to Scenario B described above (Figure V-11).

No additional renewables were assumed to enabled by or installed for the electrolyzer. Only energy available on the grid was used.

FIGURE V-11. Scenario E+



Note: *<u>This Scenario does not represent "green" hydrogen production</u>*. The electrolyzer would be supplied by whatever energy is available on the grid: both clean and otherwise.

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[55] *<u>Id</u>*.
[56] This Scenario is not intended to be a book report on the current developer plans for an electrolyzer installation at Delta, Utah that may or may not be powered by 100% clean energy. Instead, for purposes of illustration it represents a generic electrolyzer installation powered by electricity from the grid.

Although the electric supply on the HVDC system is likely to be a mix of clean and fossil energy, to approximate the hourly and seasonal timing of a renewable energy supply available from the HVDC system, the per-unit hourly load shape of the electrolyzer with a 210 MW peak was scaled in accordance with a the shape of energy coming from Wyoming into the IPP site on the TransWest Express line from Scenario B (with the PftP line installed). The resulting load shape had an annual load factor of about 77%.

In addition to costs, the electrolyzer operation has carbon emissions implications. Ironically, adding the electrolyzer load to the electric grid *increases* carbon emissions. But the stored hydrogen product can then be used to offset carbon emissions later. The analysis then calculated the potential carbon reduction offsets to determine the net emissions.

2. Modeling Results

The modeling results for Scenario E+ are shown at Exhibit V-3I for all RTOs and Planning Regions. In contrast to the other Scenarios that add renewable energy, this Scenario adds electric load to the grid like any other large industrial utility customer would. The results include:

- An Adjusted Production Cost *increase* across all regions of about $72 million in Year 2030.

- A cost of electric energy supplied to the electrolyzer of about $83 million in Year 2030.
    - This is a cost of:
        - $58.16/MWh for commodity electric energy supply to the electrolyzer, not counting demand charges. This is consistent with average annual LMPs in the region (Exhibit V-8A).
        - Or a cost of $2.46/kg of H2 produced, just for the commodity electric supply, and not including fixed costs associated with building or operating the electrolyzer.
        - Other regions have significantly lower market LMPs for electric supply, but do not enjoy the unique storage cavern opportunity present at Delta, Utah.

- An incremental *increase* in annual carbon emissions of about 539,000 metric tons.

3. Economic Analysis

Cost assumptions and the economic analysis for Scenario E+ are provided at Exhibits V-7W to V-7Y from both investor-owned and public financing perspectives. Financial assumptions for the economic analysis are provided at Exhibit V-6.

4. Observations

- The maximum installed capital cost of a 210 MW electrolyzer facility in 2030 installed at Delta using either investor or public power financing would need to be about zero dollars per kW to achieve a goal hydrogen production cost of $4/kg. (Figures V-12 and V-13)
  - For H2 production cost goals of $5 to $6/kg, the maximum capital cost would need to be:
    - $100,000 to $150,000 per kg of production capacity for investor financing, and $150,000 to $250,000 for public power financing (Figure V-12).
    - Or $2,000 to $4,000 per kW of demand for investor financing, or $3,000/kW to $6,000/kW for public power financing (Figure V-13).
  - An H2 production cost goal of $2/kg is not attainable for any positive electrolyzer capital cost, because the electricity supply alone costs $2.45/kg.

FIGURE V-12. MAXIMUM CAPITAL COST TO ACHIEVE VARIOUS H2 PRODUCTION COST GOALS (in $/kW peak electric demand of electrolyzer)

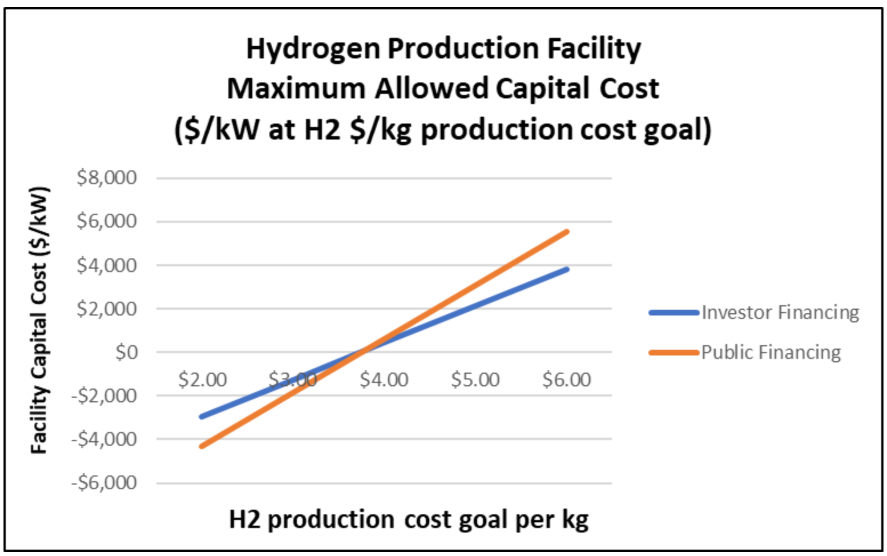
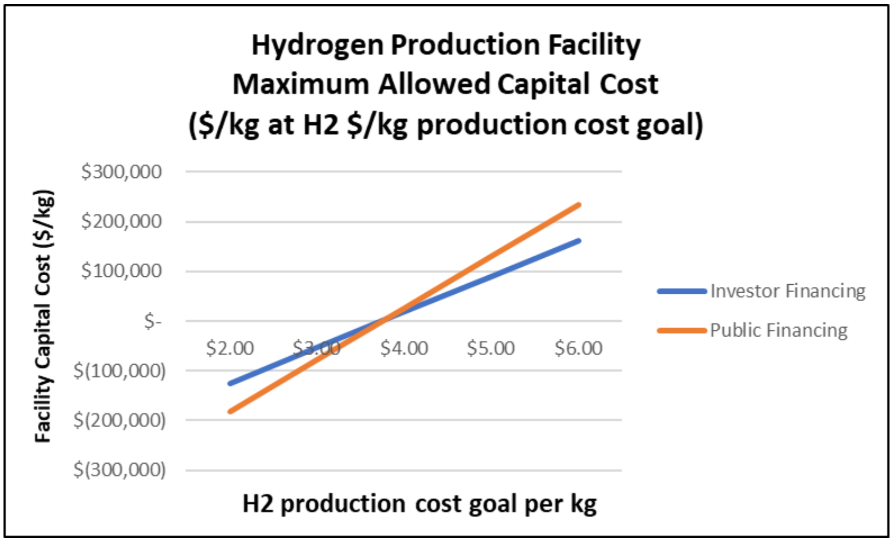


FIGURE V-13. MAXIMUM CAPITAL COST TO ACHIEVE VARIOUS H2 PRODUCTION COST GOALS (in $/kg peak output capacity of electrolyzer)



- Use of the hydrogen produced by the facility could offset about 202,000 metric tons/year of carbon emissions if used in a CCGT electric generating plant or any other end-use that entails combustion of the H2.[57]
  - These carbon reductions would tend to offset the 539,000 metric tons/year of additional carbon emissions on the grid that operation of the electrolyzer itself would cause.
  - Considering the potential savings in using the H2 to offset natural gas in end-use applications, the electrolyzer would result in a *net increase* of about 337,000 metric tons per year.

- Instead of firing the electrolyzer with grid energy as assumed here, the question becomes: How to deliver high capacity factor renewables to the electrolyzer[58], which requires interregional transmission connections to achieve, without fossil energy that also travels on the interregional transmission?[59]
  - See Figure VII-5 for an example on how to achieve high capacity factor renewables using interregional transmission like PftP.
  - Answers to this question are left for future study.

[57] Other end-uses for the H2 that do not involve combustion, such as fuel cells, could yield higher carbon reductions.
[58] The electrolyzer load factor assumed in Scenario E+ was more than 77%. Far higher than local renewables could achieve alone.
[59] The interregional HVDC transmission system is not assumed to carry 100% clean energy.

J. UNASSIGNED RENEWABLES

The Task 1 modeling included very large quantities of additional renewables – a total of nearly 12 GW across all the Scenarios. Little of these generic new renewables was assigned to particular off-takers (Table V-6).

TABLE V-6. QUANTITY AND MARKET VALUE OF UNASSIGNED RENEWABLES

Scenario	Total New Renewables (MW)	Unassigned Renewables (MW)	Market Value of Unassigned (in 2030)
A. (TransWest)	3,300	3,300	$431M
A. (Soo Green)	--	--	--
B. (PftP)	**3,000**	**3,000**	**$300M**
C. GCPSP	1,800	1,140	$110M
D. (MP Connection)	2,500	2,500	$271M
E. (Utah CAES)	1,200	1,200	$148M
E+. (Utah H2)	--	--	--

The market value of these new and unassigned renewables is massive – a total of more than $1 Billion in annual value for these 12 GW. For PftP in Scenario B alone, the market value of its 3,000 MW of added and unassigned renewables is about $300 million (Table V-6).

These unassigned renewables represent an opportunity for utilities, corporations, and other off-takers to secure production cost savings, and well as carbon reductions, by securing ownership or off-taker rights to these new renewables and taking them into their supply portfolios. Short of doing that, their APC savings calculated in this Report result only from being bystanders (and free riders) on the presence of these new renewables affecting regional market LMPs by displacing fossil resources.

K. LOCATIONAL MARGINAL PRICES

Locational marginal prices (LMP) changed in the various Scenarios. The lowest average annual prices were observed in SPP, and the highest in California. See Exhibit V-8 for details. PftP reduced LMPs in most example pricing Hubs examined but increased them in SPP and California.

PftP significantly reduced hours of negative LMPs in both SPP and California, by introducing new markets for what would otherwise be renewables over-generation.

L. CARBON EMISSIONS REDUCTIONS

The PftP HVDC line project and the additional renewables it enables would reduce annual carbon emissions by about 7.3 million metric tons. In addition, if other projects examined in this CDS, each with the additional renewables they would enable and operated in combination with the PftP line, the following annual net carbon reductions would occur *in addition to* the PftP impacts:

- The Gregory County Pumped Storage Project: 1.7 million metric tons.
- The Minnesota Power Connection: 4.2 million metric tons.
- Utah CAES: 1.5 million metric tons.

M. COST OF CARBON

With the concurrence of the CDS Participants, the Task 1 analysis used a national planning cost of carbon emissions of $16 per metric ton in Year 2030.[60] This was based on a Regional Greenhouse Gas Initiative (RGGI, www.rggi.org) forecast for Year 2030. It is also the mid-value of the range of carbon costs the Minnesota Public Utilities Commission (MPUC) requires their utilities to use in their Integrated Resource Plans (IRP).

A sensitivity analysis was performed on the Base Case to determine the effect of this carbon cost assumption. The results show that replacing the carbon cost of $16/ton with zero caused total regional Adjusted Production Costs (APC) to decline by $11 Billion, or about 17%.[61] Carbon emissions increased by 61 million metric tons, or 9% compared to the $16/ton assumption. The resulting APC cost increase for using $16/ton was about $186 per metric ton saved.

N. BENEFICIAL CHANGES IN TRANSMISSION FLOWS

The various CDS Scenarios resulted in changes in flows in existing transmission lines—often beneficially. For example, the addition of the PftP line in Scenario B resulted in a beneficial increase in the flows on the TransWest Express and Southern Transmission System (STS) HVDC lines, in both directions, with no additional investment in those

[60] This value was used for regions that do not currently have carbon costs. For regions that do (e.g., California, British Columbia and Alberta, Canada), those costs were continued in those regions.
[61] Using a carbon emissions cost causes the system dispatch to use generation sources with lower carbon emissions, but higher production costs (e.g., replacing coal with natural gas), while renewables output remains fixed.

facilities. This would improve the profitability of those lines for their owners or, in the alternative, improve the competitiveness of their $/MWh prices to their shippers and off-takers. See Exhibits V-5 for illustrations of these effects for each of the line segments considered.

Changes in flows on four of the existing, back-to-back DC tie facilities between the Western and Eastern Interconnections and near the route of PftP were also examined. These ties are currently scheduled on a daily basis. For purposes of this CDS, they were allowed to be dispatched by LMP. See Exhibit V-5J for the results by Scenario. The 4,000 MW PftP project would increase the current total DC transfer capacity across the national seam (including all seven existing ties of about 200 MW each) by 286% in both directions.

O. ABOUT LIFETIME COSTS AND BENEFITS

As described in this report, the Task 1 economics analysis compared costs and benefits in Year 2030. This choice of year was based on the detailed production cost modeling data available from MISO (for MISO, SPP and PJM), and from WECC. All associated capital and other costs were also indexed to 2030.

Such modeling data is developed by the RTOs and Planning Regions in great detail to allow utility-specific (and even more granular, individual transmission element) studies. This process is very data- and labor-intensive, and the RTOs do not develop such models for every year going forward. Instead, they develop one or two "snapshot" years of the future, often five or ten years forward.

A fair question: How do the one-year benefit/cost ratios determined in this study relate to lifetime economics? Year-by-year calculations are based on a multitude of assumptions about the future; the actual outcomes of which are currently unknowable. Yet, the lifetime effects certainly need to be considered in some manner.

The ***cost*** assumptions for Year 2030 in this CDS are primarily annual costs associated with asset investments (transmission, renewables and storage). Once the investment is made, these costs are largely fixed over the lifetime of the asset. Fixed O&M costs (largely salaries) do increase year-to-year. But their impact on the overall results is de minimus compared to investment-related costs.

The lifetime economics trends then come down to what will happen to the calculated production cost ***benefits*** modeled in Year 2030? In essence, PftP was designed from the start as a capital investment cost (e.g., steel, concrete, and polysilicon) hedge against future fuel and emissions cost increases. This is the nature of the energy transition.

The production cost benefits of the PftP project are based on LMP market prices. It is anticipated that average LMPs will decline somewhat over time as additional renewables continue to offset fossil fuel generation.[62] But their volatility will increase.

Overall, it is anticipated that increases in natural gas prices and emissions costs will be larger effects on LMPs than increasing renewables. Also, increasing electrification of the energy sector (electric vehicles and decarbonization) will likely increase future electricity demand and associated LMP costs faster than anticipated in the 2030 modeling data.

These effects cause the PftP LLC team to conclude that the production cost benefits will increase in the future compared to those modeled in 2030. Accordingly, in addition to the fact that quantification of other potential benefits of PftP listed above were beyond the scope of this study, the benefit/cost ratios determined in this study are likely to be conservative (low).

P. GENERAL CONCLUSIONS FROM TASK 1

A few general conclusions can be drawn from the Task 1 modeling and economics effort:

1. Transmission or energy storage projects that enable installation of additional renewables have significantly better economic results than those that merely serve already-existing renewables.

2. With such large project capital costs, the method of financing matters to the resulting benefit/cost ratios. Public power financing (100% debt, low-cost debt financing) is significantly lower cost than investor-owned financing that entails equity returns and associated income taxes.

    a. To encourage investor-owned entities to own such facilities, some form of state or federal government financing or involvement would be helpful to incentivize such projects that enable additional renewables and associated carbon reductions.[63]
        i. Example: A federal investment tax credit (ITC) like that offered to renewable energy and energy storage facilities in the Inflation Reduction Act (IRA) should be extended to qualifying interregional HVDC transmission and grid-level storage projects. Such an ITC has been proposed.[64]

[62] In fact, Scenario B shows small decreases (1% of less) in average annual LMPs compared to the Base Case at most of the 17 pricing hubs monitored in the study. But average annual LMPs ***increased*** in five others in SPP and WECC.

[63] As in the IRA, public power should also be allowed to participate in such ITC incentives because they have the same project risks as investor-owned entities do.
[64] S.1016 (Heinrich).

ii. Example: The Western Area Power Administration (WAPA) Transmission Infrastructure Program (TIP).[65]
iii. Or outright public/state/federal/tribal ownership of such facilities.[66]

3. Interregional transmission facilitates _energy_ transfers over long distances. But by itself is not a dispatchable source of reliable generation _capacity_. And renewables are only a partial capacity source. If capacity is needed to support retirements of aging fossil generation, some form of storage for renewables is needed. Storage is expensive. But if not storage, what other options are practically available?[67]

4. The experience of this CDS is that the logistics of assembling an internally consistent planning model of multiple regions for an interregional transmission study using datasets developed by each region separately and without interregional coordination from the start is a time-consuming, costly, and burdensome task. If interregional transmission is to be effectively pursued in large scale going forward, some form of consistent standard for such studies across all the RTOs and planning regions (i.e., model and weather year, fuel price index, consistent and appropriate time-diversified hourly load and renewables patterns, etc.) needs to be established by FERC or some other overall authority.

VI. TASK 2A: TECHNOLOGY

A. THE ANALYSIS PROCESS

The technological objective of this Concept Development Study is to design a cost-effective electrical grid that would enable large amounts of renewable energy to travel over multiple regions of the United States and be capable of delivering such renewable energy to the electric markets and urban areas throughout the country.

In addition, the new grid would be configured so that every state the grid passed through would be able to benefit from the grid.

The proposed grid will not necessarily be limited to renewable energy. However, coal and natural gas fired power resources have not needed such a bidirectional grid. The purpose of this grid is to enable efficient use of renewable energy by using geographic and time diversity over multiple regions and employing cost effective grid scale energy storage.

[65] https://www.wapa.gov/transmission/TIP/Pages/AboutTIP.aspx
[66] Example: the federal Pick-Sloan Plan that built the large hydro generation plants on the Missouri River in the 1950s.
[67] Other options might include new nuclear or fossil-fired generation. But they have their own permitting and environmental challenges.

The new grid will have to be able to operate in both the Western and Eastern Interconnections. A DC grid is the only transmission technology that can span and operate between separated and asynchronous AC power systems. We chose to use an approach that has been used or proposed in similar applications.

This Concept Development Study (CDS) requires High Voltage DC Transmission (HVDC) because HVDC has the following characteristics:

- Ability to control power flow
- Transmit power between separate AC power grids
- Lower losses than AC –particularly over long distances
- Lower cost than AC for long lines
- Low fault current
- Very fast dynamic response for better reliability
- Excellent power flow control
-

These characteristics are necessary for PftP to be both economical and reliable.

Let's consider each of these two primary technologies and then we will consider the advantages and considerations each entail.

B. LINE COMMUTATED CONVERTERS (LCC)

The first HVDC lines used Line Commutated Converters (LCC). Until the 1990s it was the only HVDC technology available. Still, today this HVDC technology is most used for the transmission of largest amounts of power point-to-point over long distances.

Line Commutated Converters are also called Current Source Converters. These converters convert AC power to DC by allowing electric flow in only one direction and by limiting the current that can flow.
The specific device that allows current to flow in one direction and can control the amount of current is called a thyristor. A thyristor was one of the first transistors, invented in the 1950s and was first used in HVDC applications in 1972.

The AC source of power is three phase power. The AC power goes through a special HVDC transformer that converts the three-phase power into six AC power phases. This transformer is important for the converter to be able to create good quality DC or AC power.

Each of these six AC phases is fed to a pair of thyristors. When the alternating current is going in one direction one of the thyristors allows it past to the positive DC output. Then when the alternating current is going in the other direction the other thyristor allows it to pass to the negative DC output.

A thyristor does not conduct electricity without instructions to do so. In order to conduct electricity a signal has to be applied to a control lead on the thyristor to turn it on. When it is turned on it conducts electricity in only one direction. The conduction continues and cannot be turned off until the alternating current changes direction. When the alternating current changes directions, the thyristor stops conducting and will not conduct again until that control lead turns it on again.
A special control system sends the signal controlling each thyristor so that each thyristor turns on at such a time that only a specific amount of current will flow through each thyristor before the alternating current reverses.

These twelve thyristors send a series of specific current pulses to the DC output, six to the positive DC terminal and six to the negative DC terminal.

The special transformer and these twelve thyristors together are called a pole. It is possible to have a HVDC system with only one pole however, it is more economical to have two poles. With a two conductor HVDC power line one pole is connected to one conductor and the other pole is connected to the other conductor.

A typical HVDC converter has two of the special transformers and 24 thyristors.

The thyristor is a semiconductor, just like a transistor or integrated circuit. Transistors and integrated circuits are made on disks of pure silicon. Then these disks are cut up into individual transistors or integrated circuits. But with these big power thyristors, the entire silicon disk is used to make the thyristor.

Each silicon disk is encased in a protective enclosure that looks like a hockey puck and has special electric protection and other protections for the thyristor. The thyristors are then assembled in a string of thyristors so that it is capable of very high voltages.
These thyristors require little maintenance and are very reliable, lasting many decades. As semiconductor technology improves in performance and price so does thyristor technology.

An HVDC converter can convert AC to DC, and it can convert DC to AC using the special transformer and thyristors.

In order for an LCC converter to convert DC back into AC it must be connected to a working alternating current power grid. An LCC converter cannot operate if the AC grid it is connected has a blackout.

The converter control system t creates current pulses that alternate from fully on in one direction to fully on in the alternate direction. These alternating current pulses are then fed into the special transformer.

These pulses are turned on with the control system. Then the thyristor turns off when the AC grid that the converter is connected changes its direction.

If the AC grid has an outage, opening the AC breakers will stop the current flow and the thyristors will turn off.

The alternating current is not a well-shaped sinusoidal alternating current wave shape. To shape the electric wave into an acceptable AC wave shape, inductors and capacitors are required. In an LCC converter, it takes an extensive number of inductors and capacitors to shape the AC waveforms into a suitable wave.

LCC converters work best in pairs, with one at each end of the HVDC line. This is called point-to-point, as the power flows from one point to another point.

LCC converters can work in a group of three if all the converter control and system protection systems are linked together with a secure low latency telecommunication system that has high reliability. The complexities of such control increase as more converters are added.

Alternating current transmission systems are not limited to point-to-point transmission connections. A single transmission or distribution line can power multiple transformers. An HVDC LCC converter can only transfer power to one other LCC converter.

The ability for HVDC converters to connect to multiple converters is called multi-terminal operation.

Because of the control and system protection issues, LCC converters are not well suited for multi-terminal grid applications.
LCC converters and HVDC transmission are very efficient. These systems have lower losses than AC systems.

Thyristors may only conduct a specific amount of current. Once that maximum current rating is achieved no additional current above that rating is possible. This characteristic limits the fault current that a thyristor might contribute to a power fault. This fault current limiting capability is beneficial because it reduces the adverse effects such high power transfers in an AC might otherwise have.

LCC converters can beneficially ride-through lightning strikes. AC systems can react to lightning with a fault duration sufficient to cause the system protection system to de-energize the transmission system. With LCC, current flow is limited, and ionization caused by the lightning strike disappear after the lightning event is complete, which is a very small fraction of a millisecond.

When one pole of an LCC powered transmission line is out-of-service, the other pole is not necessarily affected. When one pole is out of service, ground current will immediately flow. When a converter station is designed, provisions must be made to assure that the ground currents can be safely absorbed by the converter without excessive damage to underground facilities.

LCC HVDC transmission systems always operate in balance between its poles. This means that the current flow on the two conductors will be equal and there is very little inadvertent ground current.

C. VOLTAGE SOURCE CONVERTERS (VSC)

Voltage Source Converters (VSC) first became practical for power system application in the late 1990s. These devices were first developed in the 1960s for electronic applications and became widely used in electronics in the 1970s.

As the thyristor defines the operation of LCC converters, it is the bipolar junction transistor, BJT, that currently defines the operation of VSC converters.

The BJT and a related device, the metal on silicon field effect transistor, MOSFET, were developed in the 60s and 70s. Both are used extensively in electronics applications. In the 1980s low voltage power applications began to employ both BJT and MOSFET devices. A common application found in power plants today are variable speed drive (VSD) motor controls.

Electric vehicles use MOSFET and some BJT. The motors in electric vehicles are typically AC motors that are driven with DC to AC converters using MOSFET. Advanced MOSFET uses silicon carbide instead of silicon as its principal semiconductor base.

BJT are currently used for VSC converters because those devices can better handle the high voltages and high current levels needed for power transmission. BJT and MOSFET have different requirements that are important for product design, but in the end both devices are compatible with each other. MOSFET are generally less expensive as they are easier to manufacture. The future looks good for continual improvement in performance and economy for VSC converters.

Like the LCC thyristors, each BJT is made on a single silicon disk. The silicon disk is encased in a protective case that looks like a hockey puck. Protective material and systems are packaged with the BJT to ensure the BJT will have a long life.

These devices are then packaged into a single device that is capable of high voltage and high current.

BJTs work much like a thyristor except that a BJT can turn off the flow of current within the BJT. That means that a controller can turn a BJT on and off. With a thyristor a controller can only turn a thyristor on, a controller cannot turn a thyristor off. To turn a thyristor off the current flow must stop either because a switch opened, or the alternating current changed direction.

A VSC converter is much the same as an LCC converter but with some important differences.

The LCC converter creates a series of HVDC current pulses that limit the power flow to the desired level. The pair of LCC converters work together with one creating HVDC current pulses out of AC power and the other converting the HVDC current pulses back into AC power. The two converters work together to transfer a specific amount of power, each must be set to a specific scheduled or dispatched level.

A VSC converts AC power into DC power so that the voltage of the HVDC transmission line is at a specific level. A VSC converter that is producing AC power uses as much power from the HVDC transmission line as it is scheduled or dispatched to produced. Because the VSC converters producing DC power monitor the voltage of the HVDC line the producing VSC converters can automatically produce the right amount of power by monitoring and maintaining the HVDC transmission voltage to a prescribed level.

Unlike LCC converters, VSC can operate in multi-terminal configurations (i.e., you can tap a passing DC line with a VSC converter to do a radial connection) like AC transmission can do because each VSC terminal can operate autonomously.

The VSC requires a special transformer that takes high voltage, three phase power and converts it to six phases. Three phases of the six phases are in-phase with the input three phase power. The other three phases are 30 degrees out of phase with the input three-phase power.

Each of these six phases power a pair of BJTs. Current may only flow in one direction in a BJT. One of the pair of BJTs provides voltage to the positive DC terminal with the positive alternating current. The other pair of BJT provides voltage to the negative terminal with negative alternating current.

For each VSC power transformer there are 12 BJTs. The BJTs are turned on and off with a common control system. The vendors have patented ways that the common control system operates. But they can operate together so that the HVDC transmission voltage is set to a prescribed level and just the right amount of current is allowed to flow. That flow of current is determined by the scheduled amount of power.

Like LCC converters, VSC converters typically have two poles. One set of BJT powered with the special power transformer feeds the positive conductor of the transmission line. The other set of BJT powered with another power transformer feeds the negative conductor. There are two power transformers feeding 24 BJT in a single, two-pole VSC.

A VSC can either convert AC to DC or DC to AC and it can change from one to the other seamlessly.
Conversion of DC to AC can be done in a number of ways and the vendors have their own patented approach of performing such conversion. Generally, there are two approaches that are used.

One approach is to make a series of very quick pulses of power. The pulses are done at a very high frequency, on the order of 100,000 times per second. The pulses are fed into the power transformer and, in conjunction with set of inductors and capacitors, produces AC power that has a very good sinusoidal waveform with low harmonics.

The other approach is to make a series of changes to output voltage so that the output voltage from the BJTs taken together form an approximate AC shaped wave. This composite waveform is fed to the power transformer and AC power is produced that requires few inductors and capacitors.

Using both together, this multi-level approach is called Modular Multilevel Converter, MMC.

D. VSC TECHNOLOGY ADVANTAGES

VSC converters can operate in point-to-point applications as well as multi-terminal without requiring a high performance telecommunication system. This means that multiple VSC converters can be connected to common HVDC transmission with each converter either adding power to the line or taking power from the line.

VSC converters can limit the fault current they might contribute to a fault, as the BJTs can, instantly turning off current. This means that VSC converters can reduce their impact on underlying systems even more than is possible with LCC converters.

VSCs can ride through lightning strikes just as LCC are able.

VSC DC to AC using MMC can produce an AC power output that can adjust its power angle very quickly. The power angle is the relative phase of a three phase power at a specific point. The power angle determines how responsive that power source will be in serving load.

LCCs have the capability to adjust the power angle, but the VSC capability to adjust power angle is faster and over a wider range than is possible with LCCs.

When a VSC converter quickly adjusts its power output when operating in the DC to AC operating mode the result is a change in voltage on the HVDC transmission line. The other connected VSC converters operating in the AC to DC mode will detect this reduction in voltage and immediately increase the conversion of AC power to DC power.

In the event of a loss of the AC grid or local AC grid at a specific VSC converter the VSC converter can start up and restore AC power to an AC system that is experiencing a blackout.

VSC converters can black start, a capability that is not possible with LCC. VSC can black start and stay in synch with a recovering AC over a wide power angle. When an AC system is first restored with power the sudden surge in power can overwhelm a conventional generator. A VSC converter can limit the current yet stay connected to the AC system giving it more time to normalize its operation as loads are restarted.

These black start capabilities are programed responses that must be implemented for such services to be active. Such capability can be service that can be provided as desired rather than simply taken.

VSC losses are very low, even lower than LCC.

VSC land requirements are lower than LCC.

VSC MMC operations operate with very low noise levels.

E. COMPARING LCC AND VSC HVDC SYSTEMS

Traditional HVDC in the form of LCC is the best and most cost-effective technology to transmit power and energy very long distances in a point-to-point way without taps along the way. Advanced HVDC technologies based on VSC is best for robust multi-terminal applications that may require black start capabilities.

Thyristors can carry more current than is possible today with BJT or MOSFET. Thyristors are less expensive than BJT or MOSFET for some high current applications that for BJT and MOSFET require special devices.

Over time BJT technology has been able to increase both its operating voltage as well as its current carrying capabilities. Over that same time, LCC has been able to increase its operating voltages as well as its current carrying capabilities. Both technologies are semiconductor technology. They both advance as semiconductors improve and are able to carry more current and withstand higher voltages.

There are some borderline applications where the voltage and current capabilities are possible with BJT but to successfully implement them to achieve that level of performance the semiconductor must be made with high precision. In those cases, the semiconductor disks must be carefully tested to eliminate any individual disk unable to meet the requirements. Unlike integrated circuits which are cut from a single disk, a disk used in HVDC the entire disk must be perfect.
As semiconductor manufacturing improves, the failure or rejection rate also improves.

As a result, the voltage and current capabilities of BJT have improved and now it is possible to use VSC for high voltages and high current applications up to 4000 MW. That capability is expected to continue to improve over the next ten years according to Hitachi.

VSC HVDC technology is superior to LCC HVDC technology except when power flow requirements greater than 4000 MW are required, and where multiple taps are required as in the PftP application.

Individual VSC devices cost more than LCC. However, the extensive filtering of inductors and capacitors required for LCC makes the total cost of LCC and VSC nearly the same.

If multi-terminals are needed, VSC must be used.

If black start capability is needed, VSC must be used.

If the lowest impact on underlying AC systems is required, VSC must be used.
When power levels are 1000 MW and higher and point-to-point could be used LCC should be carefully considered.

Any point-to-point HVDC system should allow for LCC to be a competitive option.

For the application in this Concept Development Study multi-terminal is necessary. The capacity of line is 4000 MW and that is within the capabilities of VSC converters. Costs for both VSC and LCC at 4000 MW appear to be

Therefore, Voltage Source Converter technology is the best HVDC to consider for the Power from the Prairie CDS.

The Proof-of-Concept stage, which is the next step in the development process, should include an engineering evaluation of HVDC technology. This is a developing technology, and it is best understood by those engineers engaged in the application of HVDC.

F. COMPATIBILTY WITH OTHER HVDC AND HVAC PROJECTS

VSC HVDC technology can be interconnected with both HVDC as well as HVAC systems. VSC HVDC technology may be able to connect to Soo Green and TransWest Express at the HVDC level, also referred to as multi-terminal.

At this time, both Soo Green and TransWest Express have asked that we model the interconnection with their systems at the AC level, rather than the HVDC level.

VSC HVDC technology has the capability to limit fault current contributions from the converter making VSC able to connect to HVAC systems without increasing the fault currents beyond the capabilities of the HVAC breakers.

In setting up the Task 1 Gridview models, it was found that additional HVAC transmission resources would be required for the South Dakota/Nebraska, Raun, and Killdeer terminals. These 345kV additions are required in order to transmit the power and energy the HVDC delivers to these terminals, and to make the benefits of the PftP development directly accessible to the various CDS Participants.

The VSC HVDC technology is compatible with existing and proposed resources at all seven proposed HVDC terminals.

G. MULTI-TERMINAL SYSTEMS

Multi-terminal systems made possible by VSC HVDC technology represent an advantage for the PftP project, because it reduced the number of costly HVDC converters needed compared to LCC technology.

Electric circuits can be connected either in series or in parallel. Series is when each component in the circuit is connected from one to another and again to the next. They all share the same, common current. For example, when Christmas tree lights are connected in series, the failure of one bulb means all the lights in that series go out.

Parallel is when all the components are connected to a single common source of power and each component acts independently. They all share the same voltage source; not current. In a Christmas tree light string with parallel connections, a single light bulb failure has no adverse effect on the other bulbs.

LCC converters work in pairs, not independently. While LCC might work fine for a PftP line with no intermediate connections from Mason City, Iowa to Sinclair, Wyoming, PftP envisions providing connections to each state along the way, between the two ends. Using LCC technology, two HVDC converters would be necessary at each of the three intermediate taps between Mason City and Sinclair, with each converter pair connected together back-to-back on their AC sides.

In contrast, using VSC technology, only one converter is needed at the three intermediate locations to tap the PftP line, saving the cost equivalent of one converter at each location. The Power from the Prairie concept would not be economically possible with LCC HVDC technology.

H. CONTROL AUTOMATION AND CYBERSECURITY OF THE HVDC SYSTEM

The HVDC system requires control and automation systems that other power systems require. These automation systems are the following:

- Supervisory Control and Data Acquisition (SCADA)
- Energy Management System (EMS)
- Resource Management
- Renewable Energy Certification Management
- Scheduling
- E-Tag Management

Control of the HVDC converters is performed by the HVDC converter control system provided. Soo Green and TransWest Express have reported that they will be using Siemens HVDC equipment. Since both these systems are using a common a control system, we could employ the same system and assure a common single vendor HVDC converter control system.

In the Stage 2, proof-of-concept phase of the PftP project, experts will consider and recommend how the HVDC System should be controlled. The purpose of this report is to develop an understanding of the technology and its application for this concept.

The AC side of an HVDC converter is controlled by the HVDC system controlling the power angle of the generated AC power. The set point for such control is the Schedule.

The DC side of an HVDC converter is controlled through the Schedule, but also by monitoring the HVDC voltage level and assuring the HVDC voltage level remains within a prescribed limit.

In a multi-terminal, DC to AC power flow can be precisely controlled. This ability to control AC power flow at each converter means that power deliveries at each Interconnection can be controlled. In an AC system, power deliveries cannot generally be controlled at the Interconnection point. Instead, total Interchange with all Interconnections is controlled.

SCADA

The SCADA system controls each terminal and its components. The SCADA system links with substation operators at each terminal as well.

Any resource, including transmission, generation, or storage under the supervision or control of the HVDC system operator is under control and supervision of the SCADA.

The SCADA requires a robust mission critical telecommunications system. The telecommunication system is built with the HVDC transmission lines and those costs are included in the high level cost estimates for such lines.

The telecommunication system can be interfaced with the operational network of participating systems. All operational networks connected to the SCADA would be subject to NERC cybersecurity requirements as well as the cybersecurity requirements of the HVDC operator and the Substation operator.

The SCADA system must support all the protocols for data transfer.

The HVDC will facilitate large power flows and a large number of transactions. The SCADA system must be a capable of handling large amounts of data and high-capacity data flow and related data processing. The SCADA will require sophisticated alarming capable of sorting critical alarms based on the state-of-the-system.
Selection of a SCADA system will require SCADA expertise and HVDC technology and operations expertise.

EMS

The Energy Management System is the automation system that performs the functions of a Balancing Authority. These functions include Area Control Error, automatic resource control, boundary metering, tie management, RTO interfaces and special applications such as Energy Imbalance Market interface.

The ACE requirements for an HVDC system that operates in both the Western and Eastern Interconnections has not been defined by NERC. Western Area Power

Administration operates a system that operates in both Interconnections with two separated entities. WAPA was able to isolate the responsibilities of the two entities. In this concept it is important that the system operator is a single entity with full responsibility for its operations. It does not seem practical, at this time, to separate the responsibilities into a west and an east system.

Because the system operator operates in two Interconnections the Frequency related requirements must be defined by NERC. Fortunately, the HVDC can respond to frequency variations at each converter. With effective storage such frequency responses might be isolated to each converter. Initially it is unlikely that effective storage will be available.

Boundary metering and tie management will be needed for each Interconnection and each converter. Each resource connected to the ITO will need to be metered and made part of the Energy Management System.

RESOURCE MANAGEMENT

The Resource Management system for the HVDC system operator is a dedicated system that monitors and forecasts all resources used by the HVDC.

The Resource Management system has an accurate and up-to-date configuration of every resource, including the capability of each resource, its point-of-delivery, its location, its operating parameters, and operational status as well as planned events.

The Resource Management system must address system adequacy for projected system requirements.

The Local Marginal Pricing requirements of the system operator, if any, would be performed by the Resource Management automation.

The Resource Management system would interface with any system dispatching resources within the system operator's control or supervision that provide the system operator with data required for best operation of the system.

The Resource Management system would produce resource reports as required and maintain the database on all resources and resource operations. The system would also monitor all performance and be able to compare such performance with defined capabilities.

The Resource Management system would secure its data via the SCADA system and the telecommunications network and be subject to the cybersecurity requirements.

RENEWABLE ENERGY CERTIFICATION MANAGEMENT

The Renewable Energy Compliance Management system is needed to assure that the renewable energy resources are monitored to comply with the regulatory requirements of each jurisdiction.

The Renewable Energy Compliance Management system aligns resources with a purchasing participant.

The Renewable Energy Compliance Management system aligns the potential resources that a participant may use as well as potential resources that a participant may be prohibited from using.

The Renewable Energy Compliance Management system must manage and maintain any certificate required for renewable energy compliance.

As no participant is expected to be located within the Balancing Authority of the HVDC system all power and energy delivered to a participant would be transacted with an E-Tag and the E-Tag would contain the unit specific information to assure production and delivery of renewable energy and not duplicate any such sales.

The Renewable Energy Compliance Management system would generate required reports, retain data, and provide audit trails as will be required.

The Renewable Energy Compliance Management system would not need to be connected to SCADA, EMS, or telecommunications network. It may not necessarily be subject to the same high standards for cybersecurity of the other systems.

SCHEDULING

The Scheduling system would be capable of operating as a full scale scheduling system and LMP system.

As a Scheduling system it would forecast requirements, resource availability, and expected production by hour. It would forecast schedule shortfalls and surpluses.

It will coordinate the forecasted requirements and resource production from a to-be-defined time before the “current day” with the participants and RTO/ISO. As the forecasts change it will update the forecast each day. The schedules would be finalized the day prior to the “current day” and submitted to daily operations for review.

It would forecast the availability of time-diversified renewable in multiple locations along the HVDC line’s span and offer them into desired drop-off points by scheduling them into the various RTOs and Balancing Authorities. (BA).

The Scheduling system would then compare actual operations with schedules and note differences providing reports for compliance and Billing.

The Scheduling system may not have NERC cybersecurity requirements but high standards for cybersecurity should be considered for the Scheduling system. Unusual schedules should be noted well ahead of time. Unusual changes in schedules in the final hours should be reviewed.

E-TAGS

E-Tags will be needed for all transactions with other entities, which is virtually all transactions. The E-Tag management system checks all E-Tags for compliance with Schedule and with daily operations.

The cybersecurity of the E-Tag management system should be consistent with the E-Tag company requirements.

I. HVDC and HVAC TRANSMISSION CONFIGURAIONS

1. PftP HVDC Configuration

Unlike previous HVDC transmission lines that are typically point-to-point over long distances with single converters at each end, PftP would have multiple converters along its length. *Although significantly more expensive*, this is necessary to: a) enable interconnection of additional renewable energy resources along the way, b) to provide participants in the middle access to the benefits of the line, and c) to avoid the perception that the line is making all states in the middle of the line "flyover land" with regard to project benefits.

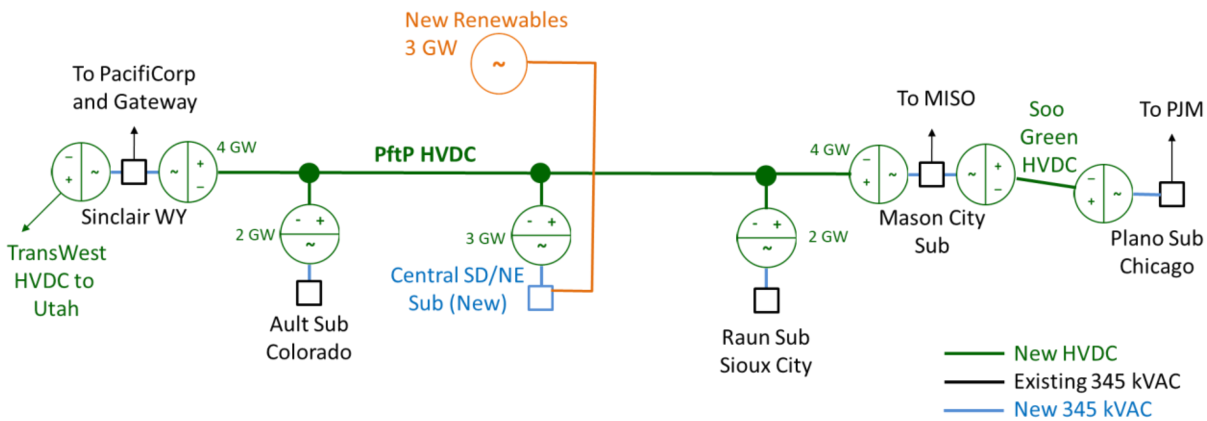
Working with the CDS Participants' Task 2 Subcommittee, the Study Team identified three additional conceptual locations for converters between the two ends at Sinclair, Wyoming, and Mason City, Iowa. The resulting five converter locations include:

- Sinclair, WY (the Northern Terminal of the TransWest Express HVDC line).
- Ault Substation, CO. (for access by Black Hills, Basin, and others)
- Central South Dakota/Nebraska (for access by MRES, Basin, and others).
    - For CDS purposes this would located be on the SD/NE state line near the Gregory County Pumped Storage Project (GCPSP) site.
- Raun Substation near Sioux City, IA (for access by MidAmerican Energy, MRES and OPPD).

- Killdeer Substation near Mason City, IA (for access by MidAmerican and MRES). This is the planned Western terminal for the Soo Green HVDC line.

Figure VI-1 provides a one-line diagram of this HVDC layout. Note that the middle three converters use the multi-terminal VSC configuration to tap the PftP lien with one converter, while the converters at the ends are back-to-back AC connections with their counterpart HVDC lines.

FIGURE VI-1. PftP HVDC Line Configuration

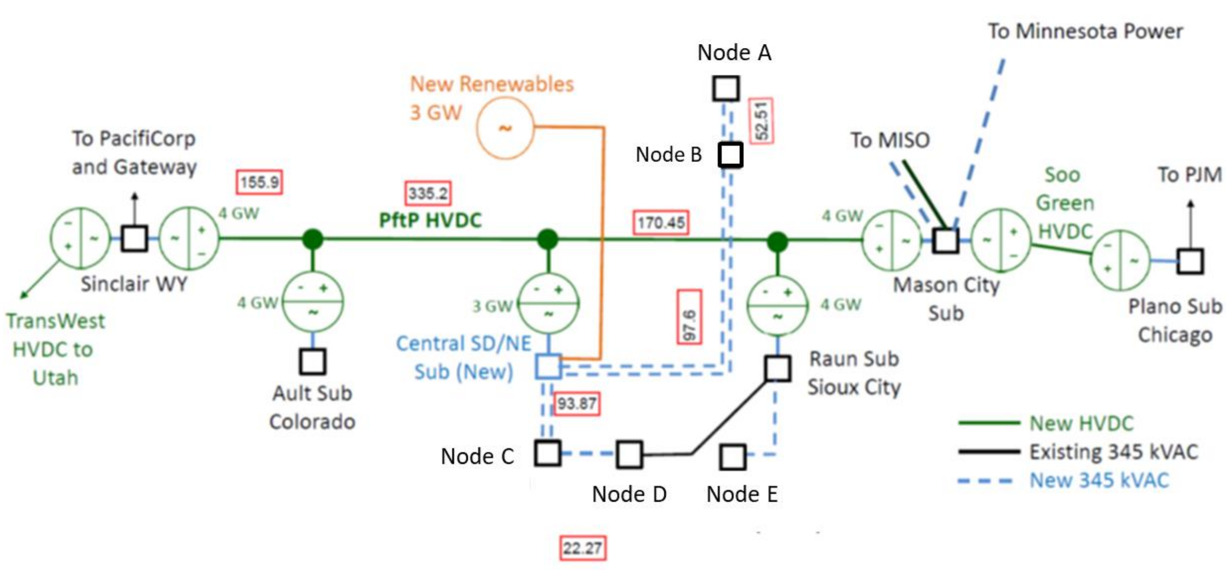


These converter locations were estimated for purposes of the CDS. Their number, locations and capacities would be optimized later, in Stage 2 of the project.

2. PftP HVAC Interconnections

The PftP HVDC line needs to be connected to the AC grid. Again, working with the Task 2 Subcommittee, the Study Team identified significant new HVAC transmission to interconnect PftP with the surrounding legacy transmission system. Each CDS Participant was offered the opportunity to identify connections they wanted to their respective systems. A Table summarizing their nominations is provided at Exhibit V-2E2. Figure VI-2 below illustrates their choices.

Figure VI-2. PftP HVAC Transmission Interconnections[68]



Like the PftP HVDC configuration, these HVAC assumptions are subject to further review and refinement in Stage 2 of the project.

3. MP Connection HVDC Configuration

The MP Connection HVDC line in Scenario D represents a significant upgrade to an existing point-to-point, +/- 250 kV for a total of 500 kV, 550 MW HVDC line from Central North Dakota to Duluth purchased years ago by MP. It currently has an existing 500 MW wind energy field at its Western end in ND.

Scenario D assumes the HVDC line would be upgraded to 3,000 MW and its voltage increase from 500 kV to 600 kV. An additional 2,500 MW of new renewables would also be added in ND. Like the assumptions in other Scenarios, the new renewables were assumed to be a 30%/70% mix of solar/wind on an energy basis.

4. MP Connection HVAC Interconnections

The upgraded MP Connection HVDC line would also need HVAC interconnections to PftP. Working with MP Staff, the Study Team defined a 345 kV interconnection from MP's Arrowhead Substation in Northern Minnesota to the Red Rock Substation at the

[68] Straight-line distances in miles shown in red boxes. Line-miles assumed to be 20% more than straight-line miles.

Southeast corner of the Minneapolis metro area, and thence Southward to the Killdeer Sub at Mason City, IA. There, it would connect with PftP and Soo Green.

The CDS Base Case included the planned MISO "Tranche 1" HVAC transmission developments. It is anticipated that the MISO process will continue to identify additional similar developments over the next few years. Accordingly, MP Staff and the Study Team estimated that the Red Rock to Mason City link could happen via the MISO process, not by MP Connection.

5. Soo Green HVAC Interconnection

Finally, initial modeling of adding the Soo Green line to Base Case in Scenario A identified transmission congestion at its Western Terminus at Killdeer Substation near Mason City. Although MISO is completing studies of this interconnection, the results of that study are not yet publicly available.

Accordingly, Hitachi and other members of the Study Team identified HVAC interconnection assumptions for Soo Green, pending results of the detailed MISO study. They assumed additional new 345 kV Connections from Mason City to Quinn and to Lakefield Junction Sub in Minnesota. This significantly reduced the congestion observed n the modeling.

J. HVDC and HVAC TRANSMISSION COST ESTIMATES

For purposes of Task 1, the capital costs of the HVDC alternatives and their HVAC interconnection lines were estimated. See Exhibits V-2 for details of these estimates.

K. RESILIENCY

Recent experience with the U.S. national electric transmission grid has emphasized the importance of resiliency (i.e., the ability to quickly adapt to or avoid the impacts of sudden, adverse circumstances). This takes three forms:

1. Energy Transfer Resiliency

Winter Storm Uri in February 2021 demonstrated the importance of electric transmission interconnectivity, or lack thereof, between regions. The Electric Reliability Council of Texas (ERCOT) region suffered extensive outages and costs due to unusually cold weather. Among other things, these problems were exacerbated by a lack of transmission connections to other regions.

In contrast, interregional transmission connections like Power from the Prairie can provide resiliency to multiple regions when they experience unusual weather conditions by providing electric supply from other, remote regions not affected by the same weather.

2. Physical Resiliency.

The recent (December 2022) unfortunate and despicable experience in Moore, County, North Carolina exposed the vulnerability of the electric grid to domestic terrorism. In this case, vandals with high-powered rifles targeted electric transmission substation equipment, causing widespread and sustained electric outages.

A PftP HVDC line, spanning hundreds of miles and carrying high levels of interregional energy might represent a tempting target for such criminal or terrorist activity.[69] One way to provide enhanced physical security for the line would be to place it entirely underground, instead of the traditional overhead construction. 'Out of sight, and out of mind. The proposed Soo Green HVDC line is a noteworthy example of how to do this.

In addition to resiliency benefits, placing the line underground would likely have benefits in the time, trouble and expense of line routing and permitting processes, as Soo Green has enjoyed compared to the relatively challenging experience of its predecessor, the Rock Island Clean Line overhead line.

Undergrounding the 970 line-mile PftP line would roughly cost an additional $2.8 Billion (in 2030$), or 75% more than doing the HVDC conductors and structures overhead, also equivalent to 20% additional total Project cost.[70] Based on the Soo Green experience, this cost increase may be offset in part by a reduction in the time and expense for routing and permitting the underground line. In the Soo Green experience, the routing and permitting was significantly enabled by using existing railroad right of way. This advantage may not be similarly available for an entire PftP project.

From a national perspective this additional cost supports the resiliency of transmission infrastructure while reducing carbon emissions by 7.3 million metric tons per year,[71] which is roughly equivalent to taking 1.6 million cars off the road.

[69] Unlike traditional AC substations that are typically located outdoors behind only chain-link fences, HVDC converter stations are typically indoors, and thereby more physically protected from casual attack.
[70] Including the HVDC line and converters, renewables, and associated HVAC transmission facilities.
[71] Assumes an average of 4.6 metric tons per year per car.

3. Virtual Storage

Finally, an interregional transmission line like PftP provides resiliency by acting like long duration energy storage. Storage is the act of placing energy in a medium for use later in time. Using interregional transmission, a utility can export its hourly or sub-hourly renewable energy over-generation compared to its own load on the transmission line. Later, it gets renewable energy back. Did physical storage actually happen? Not necessarily. The returning renewable energy could be someone else's time-diversified renewables over-generation. This is only possible with interregional transmission.

We call this "virtual storage".

VII. TASK 2B: RELATIONSHIP TO MARKETS

This Section discusses how operation of PftP will relate to markets. It entails considerations for:

- The PftP line itself.
- The PftP scheduling entity.
- Creating and marketing innovative energy and capacity products enabled by the line.

A. THE PftP LINE

The PftP line project will:

- Operate in coordination with the existing RTO and BA wholesale markets where its HVDC converters are located (e.g., SPP, MISO, and BAs within WECC's footprint).

- Not require a reorganization or merging of the existing RTO/BA markets.
  - But will likely require some adjustments in their procedures, planning, and cost recovery processes and rules.

- Sponsor its own internal and contracted engineering design and operations planning studies.

- Participate in existing transmission planning processes in the RTOs/BAs, as the incumbent PftP line owners may request as members of the RTOs/BAs.

- Participate in planning processes in the existing RTOs/BAs as may be necessary to support cost recovery.
  - Including potential treatment to spread costs over larger areas, similar to the Multi-Value Project (MVP) process with MISO, if applicable.
  - Likely necessitating FERC action to better define an interregional transmission planning and cost recovery process across the RTOs/BAs.

- Coordinate its own permissions to build, routing, and permitting processes across its various regulatory jurisdictions.
  - Federal
  - State
  - Local

- Request interconnection to the existing RTOs/BAs at its converter locations like a BA would, as the incumbent PftP line owners may request as members of the existing RTOs/BAs.
  - The interconnection studies process and queue for PftP will need to be done consistent with the scale of the PftP project.
    - A 4,000 MW PftP line enabling large quantities of renewables should not have to wait in the same interconnection queue as five MW wind or solar projects.[72]

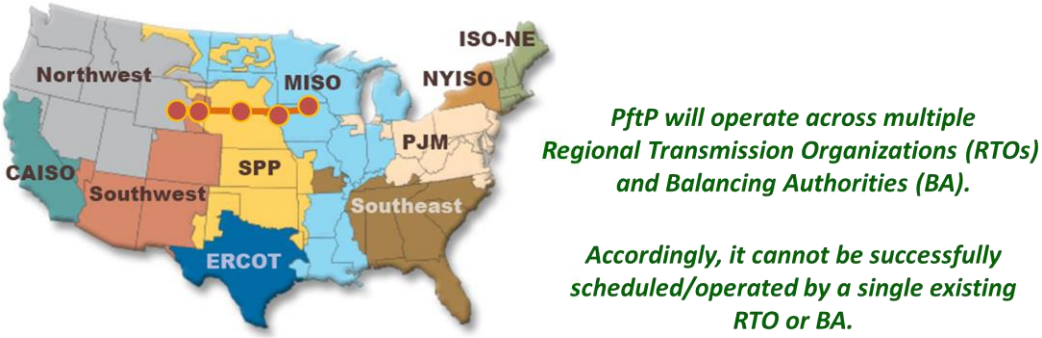
- Have its own internal interconnection queue for generation or storage connecting to its HVDC convertors.
  - The PftP line owners and off-takers may identify via their own internal and competitive processes.
    - Neither first-come, first-serve nor first-ready, first-serve.
  - Would require a FERC-approved process that could include a neutral observer to identify shippers in an open and competitive way, particularly where affiliates of PftP line owners may be involved.

B. THE INTERREGIONAL TRANSMISSION ORGANIZATION (ITO)

An interregional HVDC line like PftP will require the creation of a new operating entity in many ways similar to a Balancing Authority (BA) or an RTO. But instead of a Regional Transmission Organization (RTO), it needs to be an Interregional Transmission Organization (ITO). See Figure VII-1.

[72] The Soo Green HVDC project experienced difficulties with this kind of issue in PJM.

FIGURE VII-1. The Initial Scope of the ITO

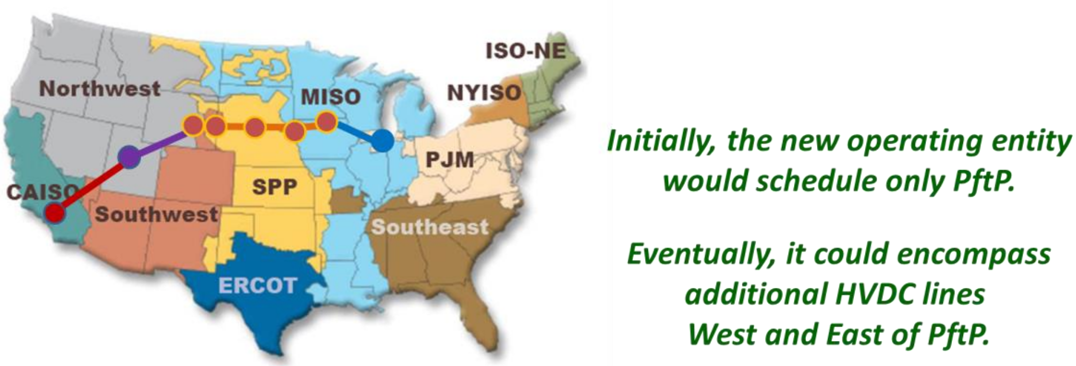


The ITO would be a new operating entity that coordinates time-diversified energy transactions across its entire length in a bi-directional manner. Single RTOs alone do not have the geographic span and view to do this on an interregional basis.

The ITO could be viewed as making the PftP line its own Balancing Area. And current cost recovery practices in the RTOs (which would be involved in interregional cost recovery for PftP as described elsewhere in this Report) require that only lines operated by an RTO are eligible for cost recovery there. This topic will need to be addressed.

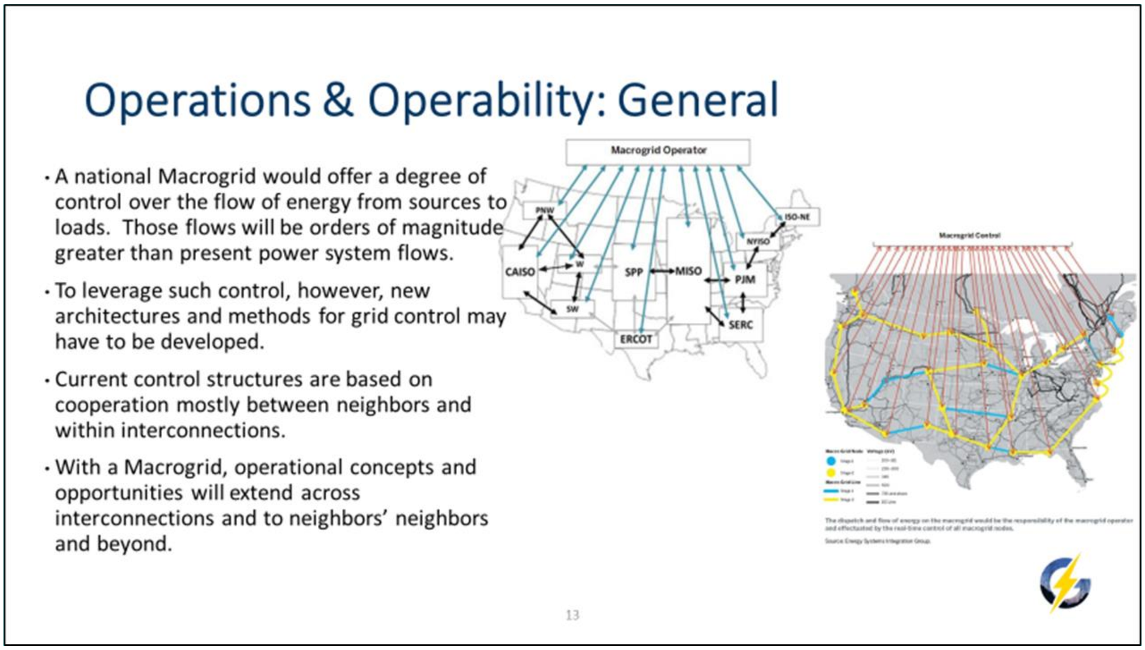
Initially, the PftP ITO would address the needs of the PftP line. Later, it could encompass the entire span from PJM to Southern California, providing the same services (Figure VII-2).

FIGURE VII-2. Future Scope of the ITO.



The Energy Systems Integration Group (ESIG, https://www.esig.energy/) a non-profit, leading source of global expertise for energy systems integration and operations including interregional transmission, created the concept of a "macrogrid operator" (Figure VII-3). The PftP ITO would be a macrogrid operator.

FIGURE VII-3. The Macrogrid Operator Concept[73]



The PftP ITO would be *like* an RTO in that it would:

- Be subject to FERC approval and regulation.
- Not own transmission or generation resources.
- Have members including transmission owners, storage owners, generation shippers, and off-takers.
- Recover its operating costs via membership fees charged to its members.
- Have a technical staff that works under the governance of the members of the entity.
    - The goal of the new entity would be to maximize value for its members.

[73] Energy Systems Integration Group, *Design Study Requirements for a U.S. Macrogrid*, at 10 (Feb. 2022), https://www.esig.energy/design-study-requirements-for-a-u-s-macrogrid/.

  - May be a non-profit organization.
  - May contract some or all day-to-day operations to a third party.

- Likely have NERC-related reliability responsibilities.

The PftP ITO:

- Would be a market participant in each of the RTOs/BAs where its converters are located.

- Would likely necessitate the existing RTOs/BAs to adopt a common approach to definition of the ELCC[74] of renewables that are combined in time-diversified packets such that their combined reliability is greater than the individual facilities viewed alone. This would likely require FERC action to redefine Resource Adequacy (RA) for shared assets to make them RA-eligible. Right now, a resource can only be counted in one jurisdiction.
  - The resulting, aggregated ELCCs would apply to RA and installed capacity reserve requirements in all the RTOs/BAs, although the capacity value of a given aggregation of renewables in individual RTOs may differ because the timing of the RTOs' peak load needs are different.

- Would likely necessitate more efforts between RTOs/BAs for interregional coordination among them.

The organizational structure of the PftP ITO is discussed in Section VIII. Regulatory considerations for the PftP ITO are discussed in Section IX.

C. THE FEDERATION INTERREGIONAL POWER MARKETER

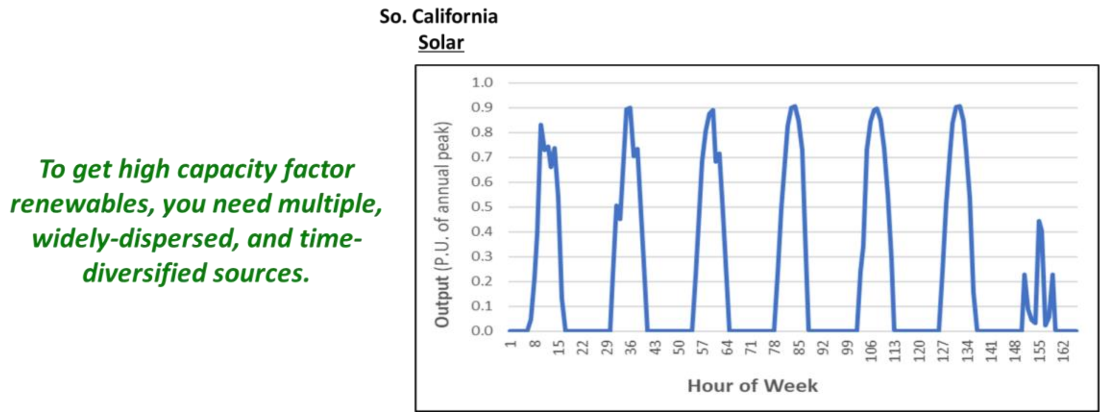
1. Geographic and Time Diversity Matters

The unique, new, and broader market view and reach enabled by an interregional transmission line and its connections to multiple RTO and BA markets via operation of the PftP ITO enables new opportunities in power marketing.

For example, without access to an interregional line, a single region (such as Southern California) may have solar facilities with an hourly output over a typical week in April that could look like the blue line in Figure VII-4. Their market opportunities and sales are based on this limited local pattern.

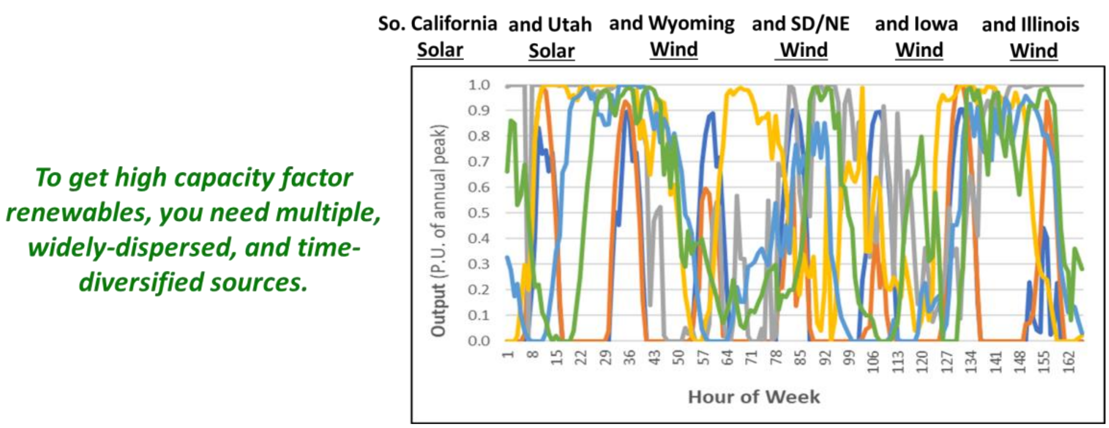
[74] Effective Load Carrying Capability (ELCC) refers to that portion of installed capacity of intermittent resources that can be used to fulfill a utility's Resource Adequacy (RA) minimum installed generation capacity requirements.

FIGURE VII-4. Time Diversity Between Renewables Matters — Hourly Generation from A Single Source[75]



But if the same region has access to time-diversified renewables from other regions over a PftP line during the same week, their market and pricing options increase dramatically (Figure VII-5).[76]

FIGURE VII-5. Time Diversity Between Renewables Matters — Hourly Generation from Multiple Sources[77]



Suddenly, the possibility of accessing renewable energy on a near-baseload and more reliable basis exists for anyone connected to the interregional transmission system (Figure VII-5). Geographic diversity between renewable resources begats time diversity

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[75] R. Schulte and F. Fletcher, *Electrolyzer Load Factor and Green Hydrogen: The Elephant in the Room*, Power Engineering, Figure 3 (Jul. 17, 2021), www.powerfromtheprairie.com/publications.
[76] The Figure represents a particular historical week example. Pick any week you want. The overall time diversity differences between geographically widely-dispersed regions are similar.
[77] *Id*. at Figure 6.

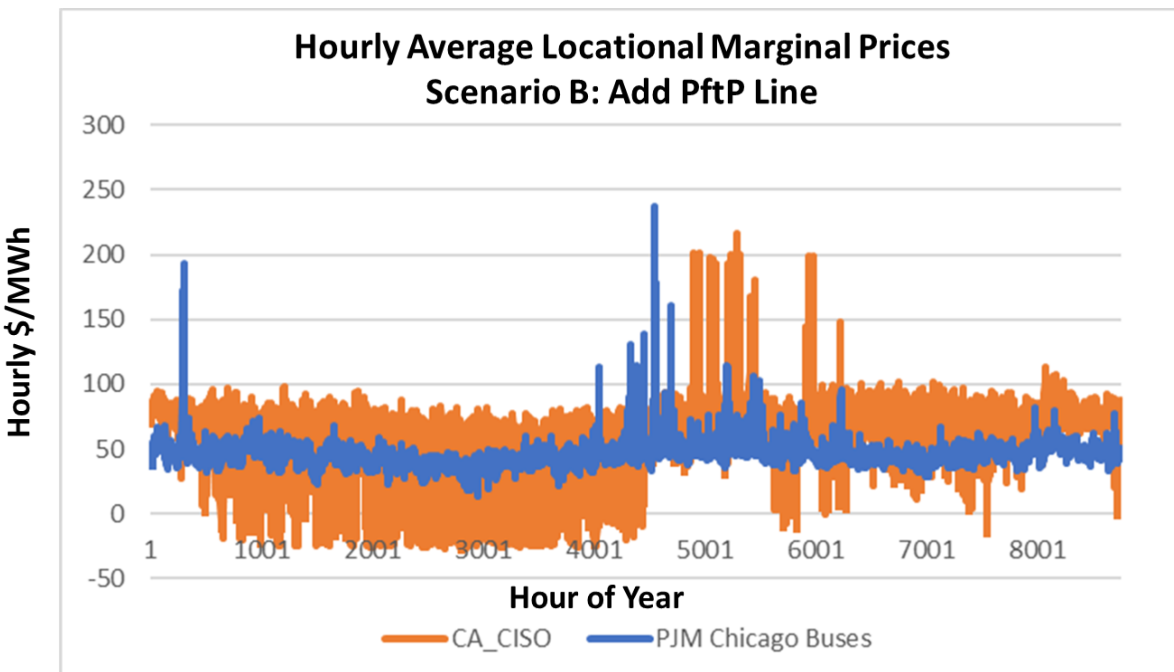
in their outputs. And time diversity matters. Renewable energy is nearly always happening somewhere. If only a way to identify and secure those resources existed. Interregional transmission like PftP with its ITO market and Federation power marketing function is that way.

Time diversity matters for costs too. For example, what if the resource represented as the yellow line on Figure VII-5, occurring at night, is over-generating in those hours compared to its local load and thus is experiencing low Locational Marginal Prices (LMPs)? That renewable energy would be useful in Southern California (the blue line) because the sun is down there, and their solar resources are silent.

2. Interregional Variations in LMPs

Hourly LMP vary widely between the regions. On Figure VII-6 from Scenario B of the CDS modeling, LMPs in the California Independent System Operator (CAISO) market vary widely compared to those in the Southwest Power Pool (SPP) - North Hub in Nebraska.

FIGURE VII-6. Example of Widely Varying LMPs Between Regions, CAISO and PJM Chicago.



The CAISO data shows periods of negative LMPs, indicating generation is exceeding load. These negative prices are improved somewhat from the Base Case due to the addition of PftP. Nevertheless, they persist.

But the negative LMPs in CAISO happen during daytime (solar) hours. The LMPs at PJM-Chicago are never negative. These represent marketing opportunities for a skillful marketer to accomplish energy swaps between them. Time diversity matters.

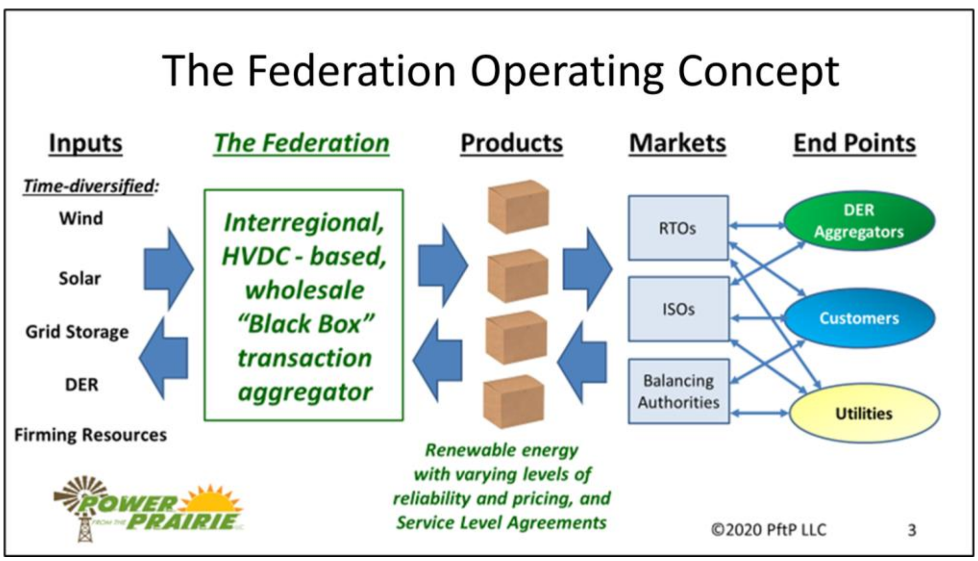
The LMP market structure will continue unchanged. But interregional transmission enables the potential for transactions between parties to further improve their economics.

3. The Federation Concept

To address the opportunities described above, The Federation is a new market concept enabled by interregional transmission. It would be an HVDC-based, wholesale black box aggregator of time-diversified resources connected to the HVDC system (Figure VII-7).[78]

It would aggregate various time-diversified generation resource inputs, combine them into various renewable energy products with varying levels of service certainty and pricing, and offer them into and out of the existing RTO/ISO/BA markets for service to end point customers.

FIGURE VII-7. The Federation Power Marketer Concept



[78] R. Schulte and F. Fletcher, *The Federation, Enabling Interregional Electric Transmission Development and Operation*, The Electricity Journal (Feb. 2021), www.powerfromtheprairie.com/publications.]

The Federation power marketer would be *unlike* an RTO or the PftP ITO in that it would:

- Create and enact innovative market products.
- Establish contract arrangements with multiple clean energy and firming capacity sources to which it is connected.
- Aggregate time-diversified clean energy and firm capacity resources at the wholesale level[79] along its interregional path and bundle them into products of various prices and reliability levels.
  - More diversified, higher load factor/higher reliability products at a higher price.
  - Less diversified, lower load factor/lower reliability products at a lower price.
  - Perhaps bundled with dispatchable firm capacity and storage resources.
- Operate on a for-profit, competitive basis.

4. Potential Federation Products

At this point, The Federation is still a concept. However, various potential market products can be envisioned.

- They will be defined by contract with specific terms and conditions.
- The performance of the agreement will be hourly and schedulable.
- Performance will be based on Service Level Agreement approach.
- Service Level Agreement will have routine provisions for:
  - Maintenance,
  - Extreme events,
  - Failure of others to perform.
- The agreements will be "Take or Pay."

Examples of the new products might include:

- Specific power and energy sales defined in certain hours and times of the year;
- Exchanges of renewable energy;

[79] Eventually, aggregated Distributed Energy Resources (DER) at the retail level may also be included.

- Firming of regional renewable energy with interregional renewable energy and other, dispatchable resources;
- High-capacity factor renewable energy power;
- Large blocks of low-cost renewable energy that can be counted upon; and
- Physical puts and calls that resource operators or utilities might use to better assure reliability.

5. *Extrinsic Value*

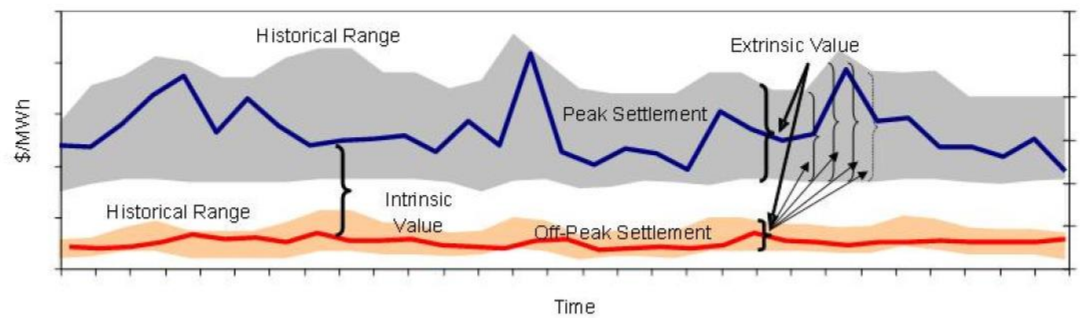
One of the more interesting opportunities for The Federation power marketer is harvesting extrinsic value.[80] This concept was previously identified in the Iowa Stored Energy Park (ISEPA) project in 2012.[81]

The benefits identified in the Task 1 modeling, based on hourly average LMPs, represent intrinsic value.[82] In addition to intrinsic value, extrinsic value represents the option value in transactions based on intra-hourly price volatility. In the ISEP project, extrinsic value derived from the ability of a fast-ramping asset (in that case, a fast-ramping compressed air energy storage (CAES) facility) to provide optionality value to pump or generate in response to intra-hour price volatility for the asset owner's benefit.

The same advantages apply to a Power from the Prairie interregional HVDC line that can enable fast-ramping, intra-hourly transactions between geographically widely dispersed and time-diversified markets that have wide volatility between their respective LMPs as the Task 1 modeling demonstrates for PftP (Figure VII-8). In the ISEPA project, extrinsic value represented an additional 30 percent to 40 percent of value compared to intrinsic value alone. This represents a potential material increase in the benefit/cost ratios for PftP and other options calculated in Task 1 if used to enable similar transaction optionality benefits. Extrinsic value is often quantified using Black-Sholes optionality techniques.[83,84]

[80] Extrinsic value measures the difference between the market price of an option, called the premium, and its intrinsic value. Extrinsic value is also the portion of the worth that has been assigned to an option by factors other than the underlying asset's price.
[81] *Lessons from Iowa*, pages 32 to 35.
[82] Intrinsic value is a measure of what an asset is worth based on its price.
[83] Black-Sholes is a method used for forward dynamic optimization and its approximation through a complex set of calendar spread options.
[84] *Lessons from Iowa*, Pages 32 to 35.

FIGURE VII-8. Derivation of Intrinsic and Extrinsic Value.[85]



On Figure VII-8 above, average hourly prices are shown as the solid lines representing average off-peak and on-peak prices for a given time period. In reality, a fast-ramping storage unit will respond to real-time RTO price signals, which have significant uncertainty and price volatility, as shown by the shaded "clouds" surrounding the average prices. In the real-time market, the storage unit will store when the volatile intra-hour prices are at their lowest. And generate when they are at their highest.

Similarly, an interregional HVDC transmission line like the PftP line with widely separated and time-diversified markets along its span, can capture extrinsic value contained in intra-hour volatile prices. The price signals are not just volatility within a single RTO, the opportunity is also the *differences* between the volatile intra-hour price signals in widely separated, multi-RTO markets. For example, the volatile average hourly prices in Figure VII-6 alone suggest there are shared savings intrinsic value opportunities in many hours between these two markets. This additional value makes PftP unique.

More importantly, these two hourly average price signals in Figure VII-6 themselves *each* have clouds of price volatility around them, like in Figure VII-8. So, the unique market opportunity an interregional line like PftP, scheduled using an the PftP ITO and with a Federation power marketing entity, is to take advantage of the differences in intra-hourly prices *between* the geographically- (and thus time-) diversified markets. These differences are likely to be more volatile, and thus more valuable, than within individual RTO markets. As a result, this unique market opportunity is even more valuable for its extrinsic value.[86] This concept would be pursued further in Stage 2 of the project outlined in Section VIII.

[85] *Id*, Figure 3 at Page 32.
[86] In addition to direct monetary value, the concept may also apply to achieving hourly or intra-hourly Renewable Energy Credits (RECs). This would be useful for companies interested in proving they are using 100% clean energy in every hour of their electricity consumption. For example, this could be a very valuable construct for proving production of clean hydrogen from widely dispersed and thus time-diversified renewable energy sources.

6. Subject to FERC Regulation

As a power marketer, The Federation would be subject to FERC review and approval. While The Federation would be a market participant in the PftP ITO, it would necessarily be organizationally separate and independent from the ITO which would also be subject to FERC approval and regulation in separate proceedings.

The organizational structure of The Federation is discussed in Section VIII. Regulatory considerations for the Federation are discussed in Section IX.

VIII. TASK 3A: PROJECT ORGANIZATION

A. INTRODUCTION

1. Proposed Project Organization

The Power from the Prairie interregional electric transmission project will help resolve the nation's energy crisis by an efficient, equitable and economical exchange, or swap, of the excess renewable energy (compared to load) generated across the country and to get it to where it is most needed. To do so, industry, federal, state and tribal governments, and interested stakeholders will join together in a Public Private Partnership (PPP) to develop the PftP project, market the energy (The Federation power Marketer) and schedule (The PftP Scheduling ITO) for delivery on demand.

A Public Private Partnership (PPP) is a unique cooperative agreement between private and governmental entities. It is best described by the July 2021 Department of Homeland Security publication "Building Private-Public Partnerships," [87] which gives valuable guidance on PPP case studies, PPP Charters and Membership Agreements, Engagement Agreements, and guidance regarding intellectual property.

On December 15, 2022, FERC highlighted[88] the importance of intergovernmental (i.e., federal, state, and tribal) cooperation regarding the nation's power grid. Industry parochialism, especially in light of *West Virginia v. EPA*,[89] is disfavored, giving credence to a PPP solution.

The proposed PftP project organization is summarized on Figure VIII-1:

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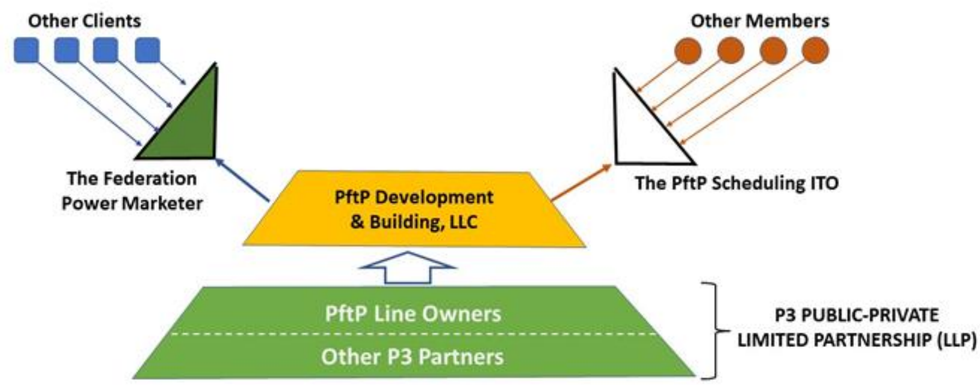
[87] DEPARTMENT OF HOMELAND SECURITY, BUILDING PRIVATE-PUBLIC PARTNERSHIPS, (Jul. 2021) https://www.fema.gov/sites/default/files/documents/fema_building-private-public-partnerships.

[88] A "Study of Effectiveness of Physical Reliability Standards for Power Grid" (FERC News release 12/15/22). https://www.ferc.gov/news-events/news/ferc-orders-study-effectiveness-physical-reliability-standards-power-grid

[89] 142 S. Ct. 2587 (2022).

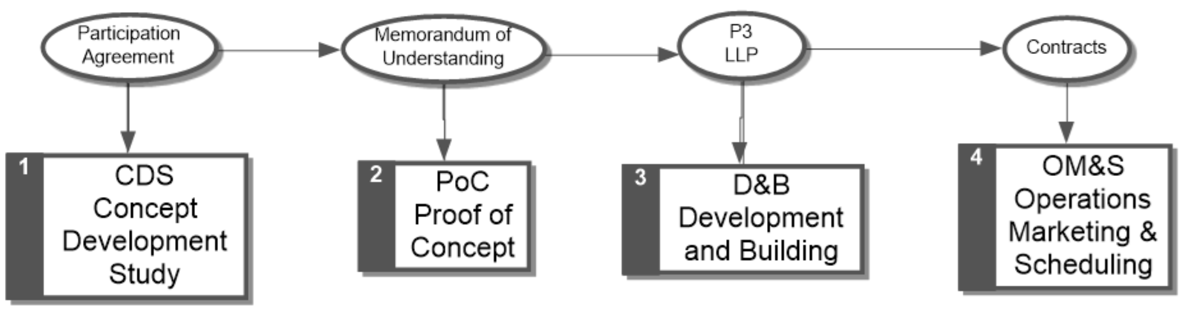
FIGURE VIII-1. Proposed PftP Project Organization



2. Four Project Stages

A four-stage process is necessary to bring the project to fruition. The four stages are illustrated on Figure VIII-2:

FIGURE VIII-2: The Four Project Stages of PftP Project Development



B. OVERVIEW

Task 3A addresses the organizational structures that will be necessary to accomplish the goals of the PftP project. As the CDS Participants' Review Committee chair, Dawn Lindell, GM of Burbank Water & Power, stated "the nation's energy problem requires a national solution."

Complex, long term, and geographically extensive projects involving multiple and diverse participants require an evolutionary approach to legal organizational structure. As the project evolves through its four stages, the organizational structure must also evolve. Consequently, it stands to reason that we maintain a keen focus on the ultimate goals of the project as the Participants, their organizational structure and the project itself evolves from stage-to-stage.

1. The Task

The project goal is use interregional transmission to support an efficient, equitable, and economical clean energy transition by enabling the installation of large quantities of additional clean energy, and to exchange or swap of excess hourly renewable energy generation (compared to load) when it occurs across the country and to get it to where it is most needed and most valuable. How the goal is accomplished and at what cost is the subject of this CDS.

In addition to being technically innovative, it is geographically expansive and interregional in scope. It will involve multiple and diverse participants, each with unique and sometimes proprietary interests. The Task 3A mission is to formulate an organizational strategy that will accomplish the mission while satisfying the needs of the participants. As described below, the Task 3A Subcommittee believes it has accomplished the mission.

2. Terminology

Task 3A concerns the legal and business structure of the various stages of the project. Consequently, it is written to communicate to the business and legal elements of the present and prospective participants.

Public Entities

For example, in Tasks 1 and 2 the term “public” utility refers to municipal, cooperative, and public power district (PPD) entities that are typically non-profit and self-regulated. In utility parlance, “public power” often refers to municipal utilities only; not cooperatives.
For the sake of simplicity, in this CDS all non-profit utilities are called “public.” In this report, when the term “public” is used regarding a participant, it more broadly references a governmental entity, for example the federal government, a state, or tribe, and not just public utilities.

Private Entities

When a “privately owned” or “investor-owned” entity is referenced, it usually refers to a private company which is not a governmental entity and operates on a for-profit basis. Examples would be investor-owned utilities (IOUs) or merchant transmission or independent power producers (IPP).

Stakeholders

In the context of the PftP project, a "stakeholder" is any individual or organization that has a direct or indirect interest in the outcome of the project. This can include the communities where the project facilities will be located, trade allies (e.g., renewable energy associations, or equipment vendors), environmental groups, and other individuals or groups who are impacted by the project in some way. Stakeholders can have different levels of involvement in the project, and their interests and needs may change as the project progresses.

As will be discussed below, it is imperative for the PftP project managers to identify and engage with stakeholders early in the project to ensure that their needs and concerns are considered throughout the project lifecycle—and not just in a reactive mode in response to required permitting or line routing filings.

C. FAILURE ANALYSIS

It can be useful to study the failures of complex projects to learn from past mistakes and avoid repeating them in the future. By analyzing the reasons why prior complex projects failed, project managers can identify common pitfalls and take steps to avoid them. This can help to increase the chances of project success and minimize the risk of organizational failure.

There are many potential reasons why complex projects may fail. Some common reasons include inadequate planning and preparation, poor communication and collaboration among stakeholders, unrealistic deadlines and budgets, and a lack of clear goals and objectives. Additionally, external factors, such as changes in market conditions or shifts in funding priorities, can also contribute to the failure of complex projects.

By studying the reasons why prior complex projects failed, project managers can gain valuable insights and develop strategies to mitigate these risks. This can include developing more detailed and comprehensive plans, improving communication and collaboration among stakeholders, setting realistic deadlines and budgets, and defining clear goals and objectives. Additionally, project managers can take steps to monitor and adapt to external factors that may impact the project, in order to increase the chances of project success.

Overall, studying the failures of other transmission projects can provide valuable insights and help project managers to avoid common pitfalls and increase the chances of project success. Project managers and their legal departments, however, are often reluctant to discuss why or how their projects failed. Some common reasons include a lack of time and resources, a lack of support from senior leadership, and a fear of negative consequences, such as damage to their reputation or career prospects. Organizational failures are not unique and are experienced throughout the world. In summary, the more complex the project the greater the risk of project failure and delay.[90]

Differing Institutional Cultures

Projects fail for many reasons such as inadequate planning and preparation, poor communication and collaboration, and funding issues. Likewise, projects which bring together participants from different institutional cultures can be vulnerable to participant bias.

Bias refers to the tendency of individuals to favor certain ideas or perspectives over others, based on their own beliefs, experiences, and backgrounds. This can lead to decision-making and problem-solving processes that are influenced by personal biases, rather than objective facts and evidence. In a project setting, individual participant bias can lead to a range of problems that can increase the risk of failure. For example, bias can lead to the exclusion of certain perspectives and ideas, which can limit the range of options and solutions considered. This can result in suboptimal decisions and inadequate problem-solving, which can increase the risk of project failure.

In a project setting, individual participant bias can lead to a range of problems that can increase the risk of failure. For example, bias can lead to the exclusion of certain perspectives and ideas, which can limit the range of options and solutions considered. This can result in suboptimal decisions and inadequate problem-solving, which can increase the risk of project failure.

Participant Bias

Additionally, individual participant bias can also lead to conflicts and misunderstandings among project participants. If team members are influenced by their own biases, they may not fully understand or appreciate the perspectives of others, which can lead to disputes and disagreements. This can impair communication and collaboration, which are critical for the success of any project.

Overall, the risk of project failure can be increased by individual participant bias, as it can lead to suboptimal decision-making, conflicts, and misunderstandings among project participants. By recognizing and addressing bias, project participants can help to mitigate these risks and increase the chances of project success.

For example, in a public-private partnership between investor-owned utilities, state and

[90] *See* Goutom K. Pall, Adrian J. Bridge, Jason Gray and Martin Skitmor, *Causes of Delay in Power Transmission Projects: An Empirical Study*, Energies 2020.

tribe participants, and public or municipal power utilities, there is likely to be a range of institutional biases that can impact the success of the project. Institutional bias refers to the tendency of organizations to favor certain perspectives and ideas over others, based on their own beliefs, values, and priorities.

One potential institutional bias that may be encountered in a public-private partnership that can be foreseen is a bias towards profit maximization on the part of investor-owned utilities. Investor-owned utilities are typically focused on maximizing profits for their shareholders, and this can lead to a bias towards cost-cutting and efficiency over other priorities, such as environmental protection or public service. Another potential institutional bias that may be encountered is a bias towards regulatory compliance on the part of state and tribe participants. State and tribe participants may be subject to a range of regulations and policies that govern the provision of utility services, and this can lead to a bias towards meeting these requirements over other priorities, such as innovation or collaboration.

Finally, public or municipal power utilities may also have their own institutional biases, such as a bias towards serving the public interest or a bias towards maintaining their own autonomy and control. These biases can lead to conflicts and misunderstandings with other participants in the partnership, which can impact the success of the project.

One strategy for overcoming institutional bias is to establish clear goals and objectives for the project. By defining the project's goals and objectives upfront, project participants can ensure that all participants understand and agree on what they are trying to achieve. This can help to reduce misunderstandings and conflicts that may be caused by differences in priorities and values.

Another strategy for overcoming institutional bias is to improve communication and collaboration among the various participants in the partnership. By facilitating open and honest communication, project managers can help to build trust and understanding among the participants. This can help to reduce misunderstandings and conflicts that may be caused by differences in perspectives and biases.

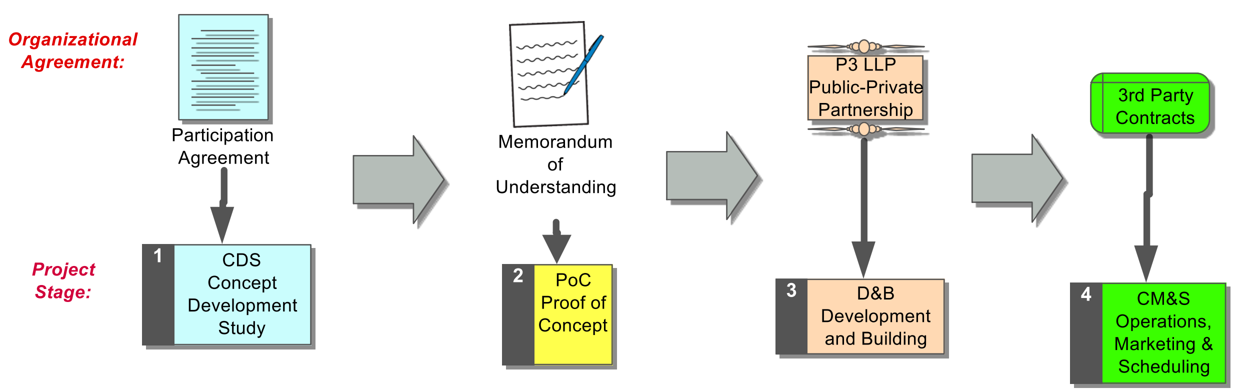
Finally, project participants can also implement strategies to mitigate potential conflicts and misunderstandings that may arise due to institutional bias. This can include implementing conflict resolution processes, such as mediation or arbitration, and implementing governance structures, such as steering committees or advisory boards, to facilitate collaboration and decision-making.

Overall, there are several strategies that can be used to overcome the institutional bias between public or municipal power utilities, state and tribal governmental units, and investor-owned utilities. By implementing these strategies, project managers can help to reduce misunderstandings and conflicts, and increase the chances of project success.[91]

D. FOUR-STAGE EVOLUTIONARY PROCESS

Like their counterparts in the complex biological organism world, complex project organizations are subject to the phenomenon of structural evolution. The Power from the Prairie project is a four-stage project which will experience organizational structural evolution as it passes from one stage through another (Figure VIII-3). An initial review of the individual evolutionary stages is important for proper decision-making perspective. Note that each stage is preceded by a relationship agreement defining the terms of participation and the expectations to be accomplished during the stage.

FIGURE VIII-3. Proposed Four Stages of the PftP Project



The Task 3A study group was asked to advise regarding the legal organizational structure that could best minimize the risk of organizational failure and maximize the potential for project success for each of the four stages. For example, Stage 1, the CDS was facilitated by the written Participation Agreement of the present CDS Participants.

As the project evolves to Stages 2, the Proof-of-Concept (PoC) Stage, a more detailed Memorandum of Understanding is envisioned with not only the present Participants but additional new Participants and stakeholders. A formal and detailed legally recognized business entity will be required among the parties. When the project evolves to Stage 3, the actual development and building of the transcontinental line, that entity must have legal authority and financial ability to establish consulting and construction contracts for

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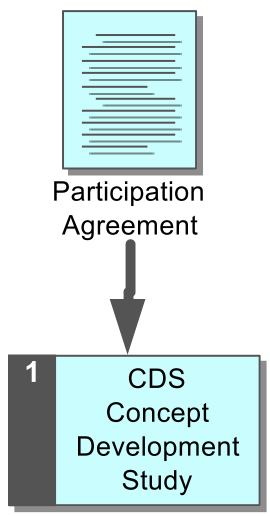
91 See, for example, Shore, B. (2008). *Systematic biases and culture in project failures*. Project Management Journal, 39(4), 5–16.

the project. In Stage 4, that entity must also have the authority and ability to enter into contractual relationships with those independent entities that operate the line, market the power and schedule the delivery.

As the project evolves from Stage to Stage, the project's organizational structure will change in order to accommodate the needs of existing, new and future partners. Consequently, it becomes important to develop an organizational strategy that is flexible. For example, while a Memorandum of Understanding (MOU) will usually satisfy the needs of Participants in Stage 2 – Proof of Concept, it is wholly inadequate to facilitate the legal relationship required by Stages 3 and 4, notwithstanding the fact that the legal relationship formed by the MOU forms the basis for the new legal relationship supporting Stages 3 and 4.

FIGURE VIII-4. Stage 1: The Concept Development Study (CDS)

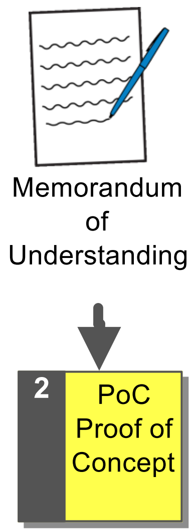


This CDS is Stage 1 (Figure VIII-4). The Stage 1 CDS Participants are motivated by a variety of independent interests and motives concerning their participation.

a. Relationship Agreement: Current CDS Participation Agreement addressing participation requirements and funding.

b. Expectation: Research, Investigation, and Report concerning the feasibility and economics of a national solution to the national energy development of a transcontinental energy transmission line to facilitate an efficient, equitable, and economical distribution of the excess energy generated in the Midwest to west coast where it is most needed, identifying potential geographical pathways and essential participants.

FIGURE VIII-5. Stage 2: Proof of Concept



The proof of concept (POC) Stage (Figure VIII-5) is a specific stage within a project that is focused on determining in greater detail and specificity whether a proposed concept or approach is feasible and viable. This stage typically involves conducting a small-scale test or prototype of the concept to see if it can work in practice and achieve the desired results. It is often a critical part of the early stages of a project, as it helps to identify potential issues or challenges and allows project teams to make informed decisions about how to proceed. For example, Stage 2 of the PftP project would likely include additional production cost and transmission power flow modeling, and initial contacts to potential additional participants, states, tribes, and stakeholders.

It is important to validate the feasibility and potential value of the concept before investing significant time and resources into further development. If the POC is successful, it can provide evidence that the concept is worth pursuing and can serve as a foundation for further development. If the POC is not successful, it may be necessary to revise the concept or pursue a different approach.

a. Relationship Agreement: Memorandum of Understanding addressing participation requirements and funding.

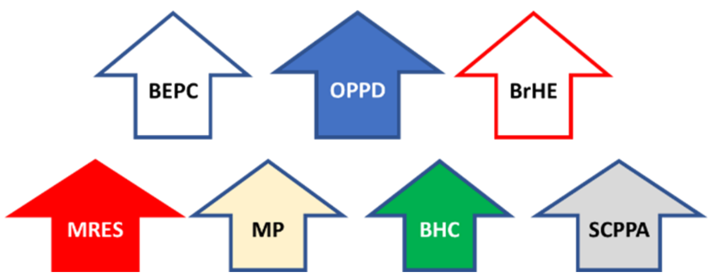
b. Expectations: Strategic reports regarding and defining the (i) engineering requirements, (ii) project costs and expenses, (iii) project regulatory permits and licensing, (iv) necessary participants, (v) necessary stakeholders and (vi) project liaisons and (vii) legal barriers to project development, building, and participation.

As described below, the POC concludes with the creation of a Public Private Partnership (PPP) between public and private industry Participants, federal, state, and tribal governments, and stakeholders from industry and financial participants. The PPP builds and develops the project through a wholly owned subsidiary, PftP Development and Building, LLC which operates the project utilizing subject matter experts, the PftP Scheduling ITO, and The Federation LLC.

As the project evolves through the four stages, the cohort of participants expands. Four classes of participants are necessary to achieve the desired goal.

1. Stage 1: Concept Development Study (CDS)

FIGURE VIII-6. The Stage 1 CDS Participants



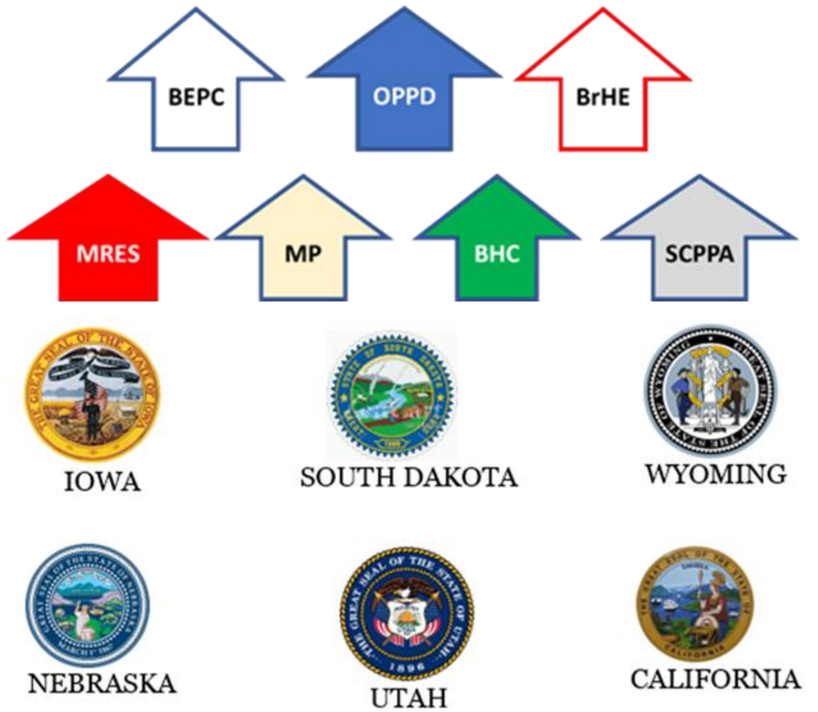
Per the CDS Participation Agreement, The Stage 1 CDS Participants include (Figure VIII-6): Basin Electric Power Cooperative (BEPC), BHE U.S. Transmission, LLC (BrHE), Black Hills Corporation (BHC), Minnesota Power (MP), Missouri River Energy Services (MRES), Omaha Public Power District (OPPD) and Southern California Public Power Authority (SCPPA) /Burbank Water & Power.

2. Stage 2: Proof of Concept (POC)

Stage 1 CDS and Stage 2 POC differ significantly regarding the type and motives of the participants. While Stage 1 CDS participants are motivated by a variety of independent interests and motives concerning their participation, Stage 2 POC participants should be expanded and consist not only of Stage 1 CDS participants, but also a cohort of stakeholders who have a vested interest in the outcome of the project (Figures VIII-7 and VIII-8).

In the Stage 2 POC the concept will be tested to ensure its feasibility and viability, the cohort of participants must include all stakeholders and interested parties. In addition to the original CDS Participants, the Task 3A team identified two additional key stakeholders: states and tribes, whose participation is essential.

FIGURE VIII-7. Stage 2 Participants Including Potentially Affected States



In addition to the six interested states, the project will also potentially affect multiple tribal nations and individual tribes located therein (Figure VIII-8).

FIGURE VIII-8. Stage 2: Potentially Affected Tribal Nations

TRIBAL NATIONS OF WYOMING

TRIBAL NATIONS OF NEBRASKA

TRIBAL NATIONS OF SOUTH DAKOTA

TRIBAL NATIONS OF UTAH

Importantly, a national solution to a national problem requires participation by the US Department of Energy (DOE) and the Federal Energy Regulatory Commission (FERC) (Figure VIII-9):

FIGURE VIII-10. Stage 2 Stakeholders: U.S. DOE and FERC

As previously indicated, stakeholders can have different levels of involvement in the project, and their interests and needs may change as the project progresses. The purpose of Stage 2 POC is to determine how those interests and needs are met.

Project Liaisons

Stakeholders should not be confused with project liaisons. A project liaison is a person or group that serves as a connection between the project team and another organization or entity. The project liaison's role is to facilitate communication and coordination between the project team and the other organization, and to ensure that the needs and interests of both parties are taken into account.

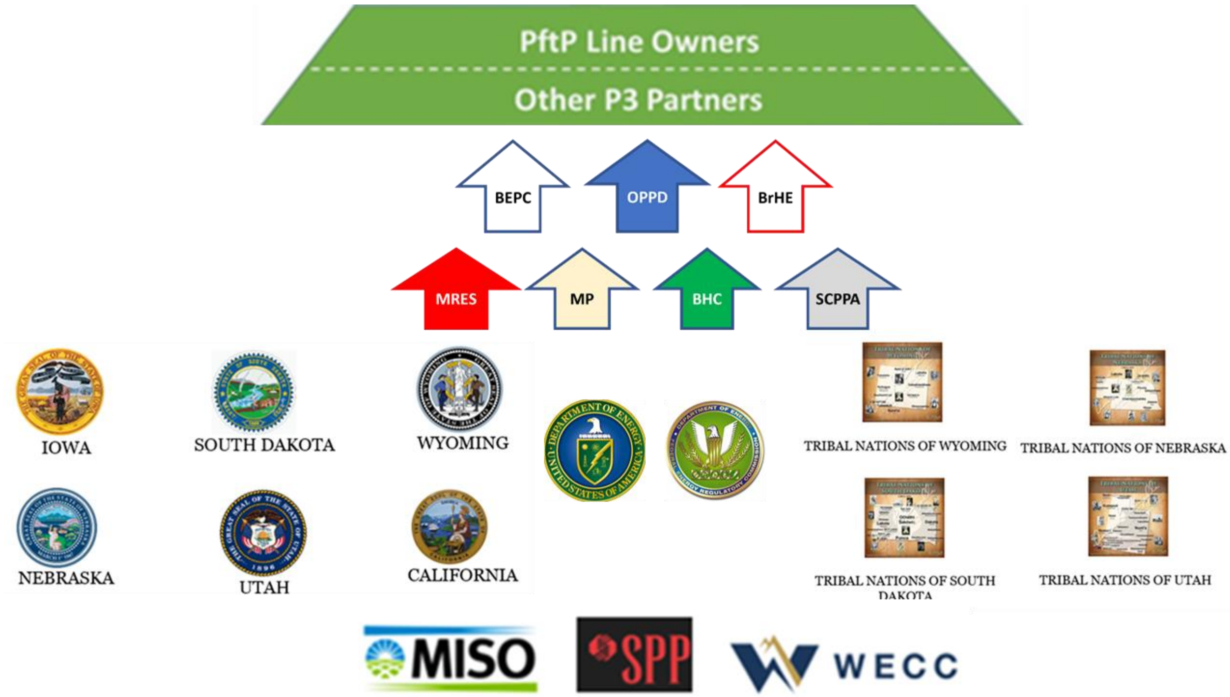
While the roles of a project liaison and a stakeholder may sometimes overlap, they generally have different roles and responsibilities within a project. A project liaison is focused on facilitating communication and coordination between the project team and another organization, while stakeholders are concerned with the impact of the project on their own interests and may be involved in decision-making and other aspects of the project.

To date, Power from the Prairie is greatly benefited by liaison with six CDS Observers: James Okullo of Midcontinent Independent System Operator, Clint Savoy of Southwest Power Pool, Saad Malik of Western Electricity Coordinating Council, and Hamody Hindy, Carl Mas and Tara Brown of U.S. DOE whose insight and input have been invaluable.

To ensure reliable feasibility and viability as the project proceeds to Stage 2 POC, the cohort of Project Liaison should be expanded to include trade representatives whose constituents are or could be affected by the project. Potential examples may include State wind or solar energy trade associations, or municipal power or cooperative utility associations.

At the conclusion of Stage II, POC, the cohort of participants, stakeholders and project liaisons will be assembled in a working Public-Private Partnership (Figure VIII-11):

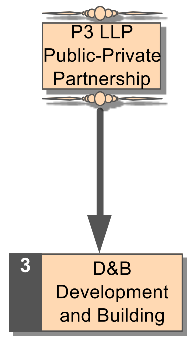
FIGURE VIII-11. The Public-Private Limited Partnership



3. Stage 3: Development and Building

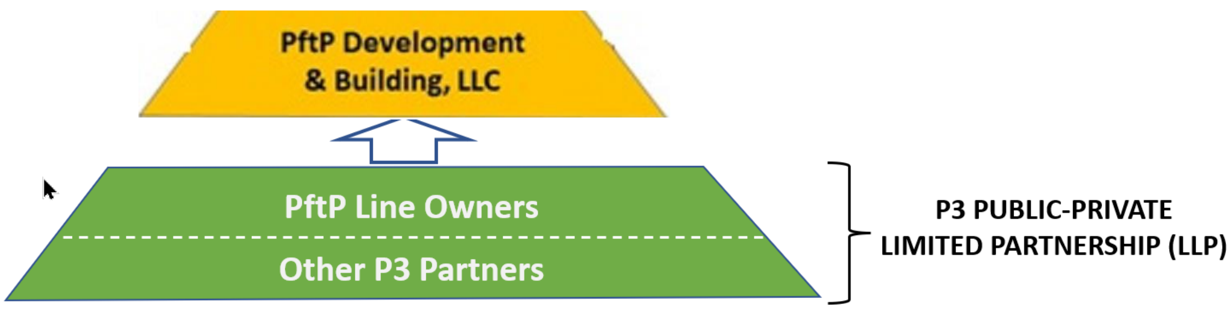
Stage 3 concerns the actual funding, development and building of the project (Figure VIII-12). Public-Private Partnership creates a wholly owned subsidiary, PftP Building and Development, LLC which addresses i) the parties' expectations, rights, responsibilities, liabilities and funding; (ii) management command, control and communications regarding partnership operation and management. (iii) Third party contractual authority regarding project building and development.

FIGURE VIII-12. Stage 3: Development and Building



Once the PPP is in place, the project can proceed to actual Development and Building of the interregional line and its associated ITO and power marketing functions, facilitated by a contract manager (Figure VIII-13):

FIGURE VIII-13. Stage 3 Development and Building, Facilitated by the PPP.

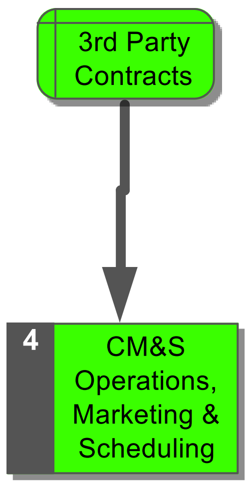


4. Stage 4: Operations Management & Scheduling

The PftP project is owned and operated by PftP Development & Building, LLC, a subsidiary of the Public Private Partnership. Operation is accomplished via two independent subject matter organizations. Scheduling is accomplished by an independent and federally regulated not-for-profit subject matter entity acting as an ITO, the PftP Scheduling ITO.

Power marketing is accomplished by an independent company that is also federally regulated, The Federation Power Marketer, LLC, under a contractual relationship with the PftP Development & Building, LLP (Figure VIII-14).

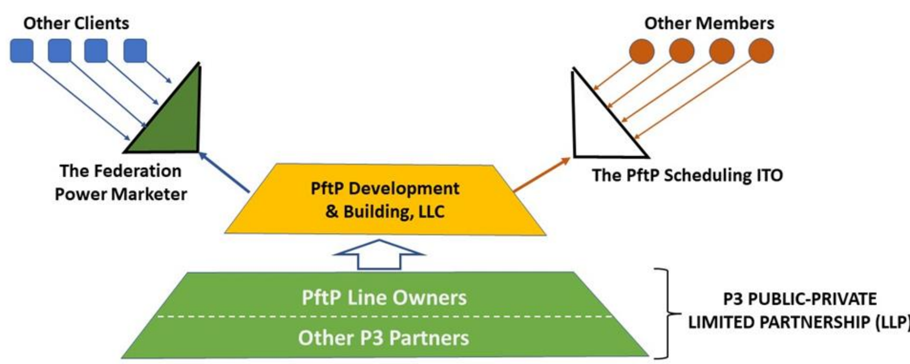
FIGURE VIII-14. Stage 4: Operations Management & Scheduling Overview



These latter two organizations are described further in Sections VII.B and VII.C of this report. The PftP Development & Building LLC creates them in Stage 3. Then, the LLC becomes one member of the PftP ITO along with other members, and one client of The Federation along with other clients (Figure VIII-15).

To ensure independence and accountability to the partnership, an independently owned and operated for-profit, limited liability company (LLC) was chosen for The Federation described on page 65. Similarly, but because of enhanced federal regulation an independently owned and operated, but not-for-profit, LLC was chosen as the organizational form for the PftP ITO.

FIGURE VIII-15. Stage 4 Organizational Relationships



E. THE PUBLIC-PRIVATE PARTNERSHIP (PPP)

1. Defining the Structure

While in some instances, governments can own stock in a corporation or be a member of a limited liability company (LLC), it is important to note that the specific rules and regulations governing government investment in businesses can vary depending on the government or tribe, and the legal structure of the business. In some cases, there may be restrictions on the types of businesses in which a government is allowed to invest or on the percentage of ownership that the government is permitted to hold. To the contrary, the public private partnership affords less regulation and offers more legal flexibility to accommodate varying governmental and tribal restrictions.

There are several factors to consider when choosing a legal organizational structure for a project. The most important thing is to choose a structure that aligns with the specific needs and goals of the project. Some common factors to consider when choosing a legal organizational structure include the size and scope of the project, the level of risk involved, the potential for liability, and the need for external funding or support.

The size and scope of the project can impact the type of legal organizational structure that is most appropriate. For example, a large, complex project may require a more formal structure, such as a corporation, in order to effectively manage the various stakeholders and resources involved. On the other hand, a smaller, more focused project may be able to utilize a simpler structure, such as a partnership or sole proprietorship.

The level of risk involved in the project can also impact the appropriate legal organizational structure. If the project involves a high level of risk, it may be advisable to choose a structure that limits the personal liability of the individuals involved. For example, a corporation or LLC can provide liability protection to the individuals involved in the project, which can help to minimize the risk of personal financial loss.

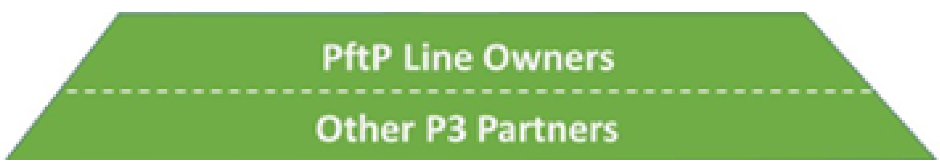
The potential for liability is another important factor to consider when choosing a legal organizational structure. If the project has the potential to cause harm to others, such as a construction project or a product development project, it may be advisable to choose a structure that protects the individuals involved from personal liability. This can help to minimize the risk of legal action and potential financial loss.

Finally, the need for external funding or support can impact the appropriate legal organizational structure for a project. If the project requires significant funding, it may be necessary to choose a structure that allows for the easy raising of capital, such as a corporation or LLC. Additionally, if the project requires the support of multiple individuals or organizations, a more formal structure, such as a partnership or joint venture, may be necessary to effectively manage the various stakeholders involved.

The Task #3A Team addressed three issues: The Organizational Structure of the project as it transitioned from Stage 2, Proof of Concept, to Stage 3 Development, resulting in Stage 4, full Operation. The Organizational Structure had to be stable and solid, yet flexible to accomplish foreseeable regulatory requirements and funding needs.

As will be seen, the Power from the Prairie goal can be achieved by forming an organizational structure known as a Public-Private Partnership (3P) (Figure VIII-16), contracting with a Single Purpose LLC for the building and development of the project, and marketed by an independent power marketing entity with transmission and distribution scheduled by an interregional RTO (or ITO). Essential for success is the enhanced participation by industry, state and tribal government and the federal government.

FIGURE VIII-16. The Public-Private Partnership (PPP)



2. Decision-Making Theory

Task #3A examined the various organizational options and issues involved in assembling a potential diverse set of participants in such an interregional HVDC effort. Among other things, these issues included:

- Types of potential legal business entities or contractual relationships.
  - For a Power from the Prairie transmission project.
  - For the Federation concept.

For each issue, the study included:

- Definition of the issue.
  - Differences between organization types.
  - The Participants' views and opinions.
  - The RTOs' views and opinions.
  - Necessary next Steps

The Task 3A Team was guided by the Power from the Prairie goal to provide a national solution to a national problem regarding energy transmission. Equitable distribution would require inclusion of participants from diverse backgrounds each operating within the distinct construct of their individual legal structure.

3. Organizational Structure: Stage 3 Development and Building

The Team took a wholistic approach to defining the type and nature of the organizational structure that would bring the participants together while maintaining the benefits from their diversity.

The five choices considered were:

- Multi-Entity, Non-Merchant, with Investor Entities
- Multi-Entity, Non-Merchant, w/o Investor Entities
- Multiple Entities, Merchant
- Single Entity, Merchant
- 3P -Public Private Partnership

The criteria used to evaluate the options were (in order of importance):

1. Project Success
2. Benefits
3. Regulatory Acceptance
4. Economic Risk
5. Public Funding
6. Private Funding
7. Legal Simplicity

Based on a careful evaluation of how well each of the five possible choices could meet the seven major criteria considered, the 3P Public Private Partnership appears to be the best choice.

- Regulatory Acceptance was the most significant factor leading to the choice of 3P Partnership over Multi-Entity, Non-Merchant, w/ Investor.

- Private Funding was the most significant factor leading to the choice of 3P Partnership over Multi-Entity, Non-Merchant, w/o Investors.

- Public Funding was the most significant factor leading to the choice of 3P Partnership over Multiple Entities, Merchant.

- Public Funding was the most significant factor leading to the choice of 3P Partnership over Single Entity, Merchant

To evaluate the differences between the five different ownership models, the Team utilized the Analytical Hierarchy process. We have modified and simplified the mathematical process described by Saaty and Bhushan for use in strategic legal decision making. The analytical-hierarchical decision-making process is a weighted analysis consisting of the identification of three coordinates: (a) the decision to be made with precision; (b) the essential criteria for selection of the resolution with each criteria evaluated and assessed against each other; and (c) the various options by which to attain the decision or goal as weighed and evaluated as against each selection criteria.

The Team asked: What is the best form of organizational structure that will bring the project to fruition? A review of prior-failed projects provides criteria for selecting the best of the available options. The details of the criteria, how they are rated among themselves, and how they relate to the available options are discussed in the following discussion. Likewise, the general detail of each option is also explored.

Organization Structure

The question of "Organization Structure" was evaluated by means of a decision table. The criteria for the decision were acquired from discussion with the participants and principals during various meetings (Figure VIII-17).

FIGURE VIII-17. Decision Table for Stage 3 Organizational Structure

	Project Success	Benefits	Regulatory Acceptance	Economic Risk	Public Funding	Private Funding	Legal Simplicity	Summary
3P Partnership	9.39	8.84	9.44	9.76	9.50	9.66	8.74	9.34
Multi-Entity, Non-Merchant, w/ nvestor	8.11	8.55	7.14	9.36	6.67	6.08	5.09	7.53
Multi-Entity, Non-Merchant, w/o Investors	6.42	8.68	6.53	6.42	8.62	1.05	8.57	6.73
Multiple Entities, Merchant	5.92	9.05	5.07	5.98	1.00	8.32	9.35	6.34
Single Entity, Merchant	4.44	8.31	4.82	4.70	1.13	9.84	10.00	5.95

On Figure VIII-17, alternative choices considered are listed down the left side of the table. The criteria used to evaluate the various options are listed along the top. Initially entered in no particular order, both the choices and the criteria were then repositioned according to importance of criteria and effectiveness of individual choices in meeting them.

As criteria is evaluated and weights assigned according to which factors are considered to be most significant, the factors are sorted from left to right in order of importance (i.e., the factor considered by the decision maker to be most significant in meeting overall needs ends up in the leftmost position).

Similarly, as choices are evaluated according to effectiveness in meeting criteria, the best choices migrate to the top of the list. When the process is complete, the best choice should emerge at the top.

As selection alternatives and the criteria to be used in evaluating them are entered into the table, weights are assigned to each of the evaluation factors so that they are ranked in order of their importance in fulfilling the overall task.

For the decision "Organizational Structure," the criteria used to evaluate the choices, and their weightings, were:

- Project Success - High
- Benefits - High
- Regulatory Acceptance - High
- Economic Risk - High
- Public Funding - Medium
- Private Funding - Medium
- Legal Simplicity – Medium

Among the five choices considered, all five were considered to be "top options." (A top option is defined as follows: If the choice immediately following the preferred choice is rated in the same rating category as the recommended selection, then all choices in that category are considered top options. If the second ranking choice is in a different category, the top options are considered to be the recommended choice plus all choices in the same category as the second-place option. Thus, the "top options" list will always have at least two choices in it, and may include all of the choices considered in the entire table.)

Discussion of Requirements

The criteria used in this decision-making process were:

- **Project Success (overall importance: High)**
  Project Success recognizes the unique nature of the project. First, the project will overcome technical barriers, e.g., AC-DC conversion; compressed air energy storage (CAES) along with various regulatory challenges attendant to a multi-state transmission project. Likewise, the project will overcome pricing, timing and a variety of economic challenges. The element of Operational Success also

represents the participants commitment to the project - the transition from observer to participant.

- Benefits (overall importance: High)
  Public interest projects are built upon the concept of public good, e.g., bringing energy from the Midwest to where it is most needed. But conceptual public good, does not fund projects or justify taking on risk. Due diligence requires a quid-pro-quo. For the Midwest energy producer, the quid presents itself as a new market to sell its energy, at a price. For the transmission line owner, the "pro" presents the opportunity to transport the producer's energy product to the consumer's market, for a price. For the west coast customer, the "quo" presents itself in the form of much needed energy, at a favorable price. Pricing becomes the denominator against which the acceptance of the economic risk spread is judged.

- **Regulatory Acceptance (overall importance: High)**
  A project of this magnitude generates economic risk which can be shared among the participants to lessen the impact on individual participants. However, it must be judged against a realistic assessment of the benefits sought to be received. In this regard, economic risk spread is the flip side of Participant Benefits.

- **Public Funding (overall importance: Medium)**
  The magnitude and size of the project confirm that public funding will likely be required to bring the project to fruition. It is most likely the funding source, at least in part, will the federal government.

- **Private Funding (overall importance: Medium)**

  Private funding is favorable because it evidences the degree of commitment of the funder. However, the due diligence attendant to private funding will require a tight focus on return on investment and profit models.

- **Legal Simplicity (overall importance: Medium)**
  High level, complex projects fail because they are over-contracted and under-covenanted. Complicated legal structure, especially concerning policy issues and dissociated decision-makers can lessen the chance of bring the project to completion and becoming operational.

  Historical large project business experience has taught that a direct and simple agreement has a greater chance of performance, especially when it is coupled with the parties' mutual covenant expressing their commitment and promises to perform. The concept of "keep it short and simple" is usually the best policy.

However, creating such an agreement becomes difficult given the diverse nature of the participants, e.g., governmental entities, tribal entities, for-profit entities, etc. each of whom respond to different constituencies.

The Top Choices

The decision-making process has identified five of the choices as "top options." They were:

No. 1. 3P Partnership

A public private partnership has been discussed in this report at Section VIII.E. The 3P is a partnership between one or more of the following:

- merchants,
- public utilities,
- investor-owned utilities,
- States,
- Tribes and
- the federal government.

The members of the partnership own a defined part of the whole project, or a part consistent with the extent of the project operations in the State or Tribe.

The reader's attention is called to 2019 Wyoming Energy Infrastructure Act, allowing Wyoming to (Wyo. Stat. Ann. § 37-5-504) "(xi) Enter into partnerships with public or private entities;" with regard to financing and building infrastructure necessary to facilitate energy transmission.

No. 2. Multi-Entity, Non-Merchant, with Private Investor Entities

Public and private CDS participants join to own the line in total or segmented. As currently planned, the transmission line will commence in northern Iowa and transverse parts of Nebraska, South Dakota, and Wyoming. This option is viewed as providing the maximum of participant ownership with risk spreading across the ownership. However, its organizational-ownership structure is complex due to the diversity of the members, e.g., governmental, and private.

Public-private ownership poses additional legal difficulties, especially in Nebraska. In that regard, it is possible that the project can be segmented with each entity owning that portion of the project that affects their jurisdiction with, of course, a corresponding sharing of costs and benefits.

Federal funding is a possibility under the Energy Policy Act of 2005, Section 1222, see: "(c) Other Funds. -- (1) In general. -- in carrying out a Project under subsection (a) or (b), the Secretary may accept and use funds contributed by another entity for the purpose of carrying out the Project. (2) Availability. -- The contributed funds shall be available for expenditure for the purpose of carrying out the Project-- (A) without fiscal year limitation; and (B) as if the funds had been appropriated specifically for that Project." In this regard, it is possible that "entity" could also consist of investor-owned entities.

No. 3. Multi-Entity, Non-Merchant, w/o Private Investor Entities

Some or all Public Power CDS Participants (OPPD, Basis, MRES) join together to own the line, particularly in Nebraska. This enables the line to cross Nebraska or South Dakota, or both. Because the project is not involved with private investor entities, member diversity is less complex as is regulation. However, eliminating investor-owned entities increases the risk spread and loss of private equity.

Because all entities are governmental, the forms of the organizational ownership become more inter-governmental or agency than commercial and must conform to the law of each state regarding inter-agency or governmental agreements, joint venture agreements, etc. You can anticipate that critical issues will most likely be policy, funding, allocation, governance, and operational control.

Importantly, Section 1222 of the 2005 Energy Policy Act could allow federal government participation and funding which would lessen the economic burden on the participants. The statute requires participation through the Western Area Power Administration (WAPA),[92] or the Southwestern Power Administration (SWPA) or both,

> "for the design, develop, construct, operate, maintain, or own, or participate with other entities in designing, developing, constructing, operating, maintaining, or owning, an electric power transmission facility and related facilities ("Project") needed to upgrade existing transmission facilities owned by SWPA or WAPA if the Secretary, in consultation with the applicable Administrator, determines that the proposed Project: (A) is located in a national interest electric transmission corridor designated under section 216(a) of the Federal Power Act and will reduce congestion of electric transmission in interstate commerce; or (B) is necessary to accommodate an actual or projected increase in demand for electric transmission capacity; (2) with the rules of, the appropriate (A) Transmission Organization, if any, or (B) if such an organization does not exist, regional reliability organization; and (5) will not duplicate the functions of existing transmission facilities or proposed facilities which are the subject of is consistent with -- (A) transmission needs

[92] The PftP project would span almost entirely within WAPA territory (See Figure VIII-26).

> identified, in a transmission expansion plan or otherwise, by the appropriate Transmission Organization (as defined in the Federal Power Act), if any, or approved regional reliability organization; and (B) efficient and reliable operation of the transmission grid; and (3) would be operated in conformance with prudent utility practice."

The Act allows participation in new facilities, provided it is "located within any State in which WAPA or SWPA operates if the Secretary, in consultation with the applicable Administrator, determines that the proposed Project-- (1) (A) is located in an area designated under section 216(a) of the Federal Power Act and will reduce congestion of electric transmission in interstate commerce; or B) is necessary to accommodate an actual or projected increase in demand for electric transmission capacity; (2) is consistent with--(A) transmission needs identified, in a transmission expansion plan or otherwise, by the appropriate Transmission Organization (as defined in the Federal Power Act) if any, or approved regional reliability organization; and (B) efficient and reliable operation of the transmission grid; (3) will be operated in conformance with prudent utility practice; (4) will be operated by, or in conformance ongoing or approved siting and related permitting proceedings.

Most importantly, Section 1222 provides "(c) Other Funds. -- (1) In general.-- In carrying out a Project under subsection (a) or (b), the Secretary may accept and use funds contributed by another entity for the purpose of carrying out the Project. (2) Availability. -- The contributed funds shall be available for expenditure for the purpose of carrying out the Project-- (A) without fiscal year limitation; and (B) as if the funds had been appropriated specifically for that Project." In this regard, it is possible that "entity" could also consist of investor-owned entities.

No. 4. Multiple Entities, Merchant

Two or more CDS Participants, join to create a merchant organization that owns the entire line, or separate segments of the line. This option is the typical joint venture where risks and benefits are shared amongst the participants. Organizational structure is simple provided the members are not diverse. Diverse membership between private and public participants become difficult and will be regulated according to state law. Federal funding may be available under Section 1222.

No. 5. Single Entity, Merchant

One CDS Participant, a private entity, owns the line. Organizationally, a single entity private ownership is non-complex. While the owner assumes all economic and operational risks, it also receives all economic benefits. However, it does come with certain regulatory risks. It is doubtful the line could be routed through Nebraska.

3P Partnership was the leading choice by a substantial margin.

Comparisons among Choices

- **3P Partnership versus Multi-Entity, Non-Merchant, w/ Investor**
  3P Partnership was considered a better choice than Multi-Entity, Non-Merchant, w/ Investor in all seven of the seven criteria considered. Of these, the critical factor was:

  - Regulatory Acceptance

  The reason 3P Partnership received a rating of Excellent for Regulatory Acceptance was: State and tribal participation enhances the probability of regulatory acceptance.

- **Multi-Entity, Non-Merchant, w/ Investor versus Multi-Entity, Non-Merchant, w/o Investors**
  Multi-Entity, Non-Merchant, w/ Investor was considered a better choice than Multi-Entity, Non-Merchant, w/o Investors in 4 of the 7 criteria considered. Of these, the critical factors were:
  - Private Funding
  - Economic Risk

- **Multi-Entity, Non-Merchant, w/o Investors versus Multiple Entities, Merchant**
  Multi-Entity, Non-Merchant, w/o Investors was considered a better choice than Multiple Entities, Merchant in four of the seven criteria considered. Of these, the critical factors were:
  - Public Funding
  - Regulatory Acceptance

- **Multiple Entities, Merchant versus Single Entity, Merchant**
  Multiple Entities, Merchant was considered a better choice than Single Entity, Merchant in four of the seven criteria considered. Of these, the critical factor was:
  - Project Success

After a careful evaluation of each option, 3P Public Private Partnership appeared to be the best organizational form for the PftP Project.

F. LEGAL OPTIONS

Having identified the optimum organizational structure, i.e., a multi-entity, non-merchant, with investor entities, the Team proceeded to address the legal form for the structure that would best utilize the subject matter expertise possessed by the diverse members of the entity. Based on a careful evaluation of how to best achieve project success and meet the criteria of:

- Organizational Simplicity
- Participant Benefits
- Public Funding
- Private Funding
- Regulatory Acceptance

The Public Private Partnership was determined to be the best legal organizational form for the project.

Public-Private Partnership.

Public Private Partnership is a unique business entity which joins both private companies and public entities (i.e., governmental and tribal units) for a common purpose. The Public Private Partnership is frequently used by government and industry to fund, build and operate entities deemed to be in the public's best interest. The success of the venture depends on mutual benefit. Without mutual benefit and effort on both sides, the partnership will not succeed.

In this case, neither government nor private organizations can provide the resources or mechanism by which to accomplish the project by working alone. But by working together they can bring the project to fruition. A Public Private Partnership between industry stakeholders, states, tribes, and the federal government will provide a unique opportunity for the private sector to proactively collaborate with government to support the interested communities, thereby facilitating the elements of diversity, equity and inclusion with regard to energy transportation and distribution.

The Power from the Prairie project found its genesis in the Iowa Stored Energy Park (ISEPA) project. ISEPA was a statutory Public Private Partnership authorized by Iowa Code Chapter 28E. These provisions from the Iowa Code explains the structure and its operations:

- **28E.1 Purpose.** The purpose of this chapter is to permit state and local governments in Iowa to make efficient use of their powers by enabling them to provide joint services and facilities with other agencies and to cooperate in other ways of mutual advantage. This chapter shall be liberally construed to that end.

- **28E.2 Definitions.** For the purposes of this chapter:
  - "Private agency" shall mean an individual and any form of business organization authorized under the laws of this or any other state.
  - "Public agency" shall mean any political subdivision of this state; any agency of the state government or of the United States; and any political subdivision of another state. For purposes of this chapter only, "public agency" also includes any federally recognized Indian tribe.
  - "State" shall mean a state of the United States and the District of Columbia.

- **28E.3 Joint exercise of powers.** Any power or powers, privileges or authority exercised or capable of exercise by a public agency of this state may be exercised and enjoyed jointly with any other public agency of this state having such power or powers, privilege or authority, and jointly with any public agency of any other state or of the United States to the extent that laws of such other state or of the United States permit such joint exercise or enjoyment. Any agency of the state government when acting jointly with any public agency may exercise and enjoy all of the powers, privileges and authority conferred by this chapter upon a public agency.

- **28E.4 Agreement with other agencies**. Any public agency of this state may enter into an agreement with one or more public or private agencies for joint or cooperative action pursuant to the provisions of this chapter, including the creation of a separate entity to carry out the purpose of the agreement. Appropriate action by ordinance, resolution or otherwise pursuant to law of the governing bodies involved shall be necessary before any such agreement may enter into force.

Statutory Public Private Partnerships provisions are not unique to Iowa. There are statutory counterparts in forty-two states, three of which concern energy projects. A variant of the Public Private Partnership was used in the US DOE and Plains and Eastern Clean Line Holdings, LLC. A copy of the Participation Agreement is in the Appendix and is illustrative of a more complex structure.

Conclusion

Public-Private Partnership was considered the best form of legal business entity by which to accomplish a national solution to the national problem. The Team envisioned at the conclusion of Stage 2 – Proof of Concept, the Participants would form a PPP and the project would transition to Stage 3 and create a wholly owned subsidiary whose purpose would be to build and develop the project which would facilitate Stage 4 Operations, Marketing and Scheduling.

G. EFFECT OF OWNERSHIP ON BENEFITS AND LINE ROUTING

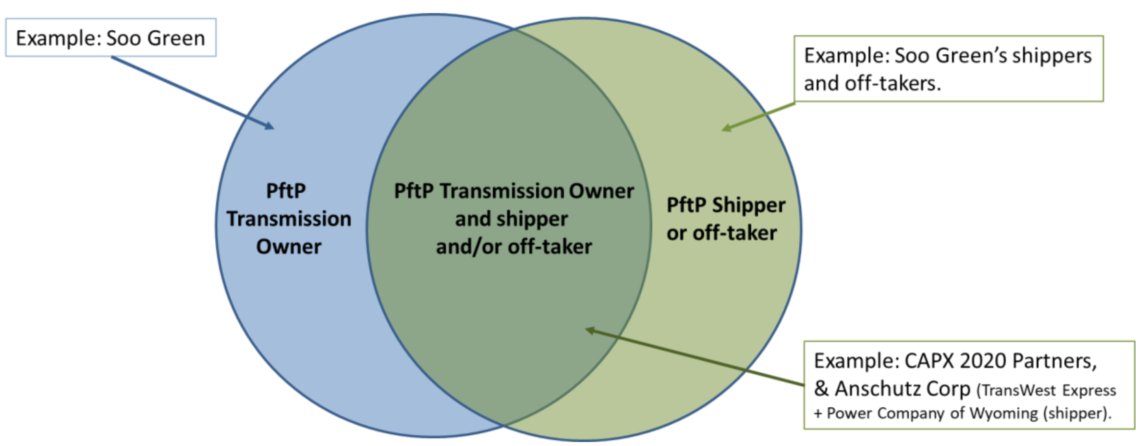
1. Effect on Project Benefits

While the focus of the CDS was primarily on PftP line ownership, the CDS Participants understood that it is not necessary to own a portion of the line to realize PftP project benefits. Regardless of whether an entity owned some of the line, the PftP project could provide them:

- A path to achieve higher level of renewables than they could using their own local renewable resource alone.
- Access to additional markets for their existing or new generation.
    - Sell output of new renewables developments to off-takers.
    - See renewables over-generation, purchase time-diversified over-generation of others.
- Reduced energy production costs for their members/customers.
- Reduced carbon emissions for their members/customers.

Accordingly, the Participants at their option have a variety of ways to secure PftP benefits (Figure VIII-18).

FIGURE VIII-18. Multiple Ways to Achieve PftP Benefits



PftP line ownership is not the only route for Participants to benefit from the PftP project.

2. Effect on PftP Line Routing

To support the Participants decisions for next steps in Stage II, the CDS Study Team also conceptualized ways PftP could be owned and operated.

- For purposes of the CDS Participants' review and discussion.
- To help focus on the line routing, organization and regulatory implications involved.

The goal was to be inclusive and show multiple ways each CDS Participant could be involved in the project. The CDS will not identify the eventual PftP ownership. The Participants will do that in Stage II.

Potential Ownership Structures

The Study Team identified five potential ownership structures. They included:

A. Incumbent Utilities[93]
   A1: Joint or segmented ownership[94] including IOU, municipal and cooperative utilities.
   A2: Joint or segmented Ownership limited to municipal and cooperative utilities only.

B. Merchant Transmission Developer Only.

C. Hybrid (including both incumbent utilities and merchants):
   C1: Segmented Ownership among merchant developers and incumbent utilities including IOUs, municipal and cooperative utilities.
   C2: Joint or Segmented Ownership among merchant developers and incumbent utilities including IOUs only.

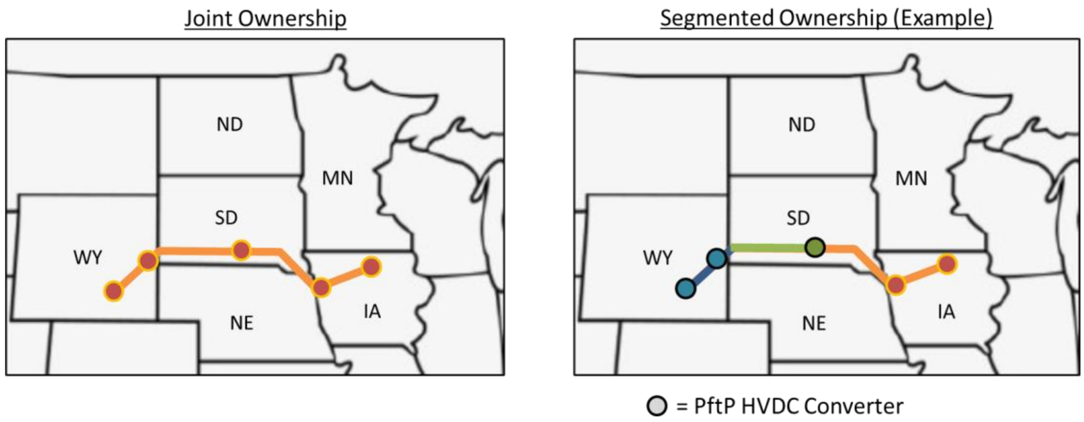
Each of these Ownership structures have potential implications for line routing.

A1: Joint or Segmented Ownership including incumbent IOU, municipal and cooperative utilities (Figure VIII-19).

Ownership including IOUs means the PftP line cannot be located in Nebraska, because Nebraska law provides only for public power ownership.

[93] See Section IX, Regulatory, for definitions of Incumbents and Merchants.
[94] The term "joint" means owners hold pro-rata MW shares of a line segment. The term "segmented" means owners each wholly own individual segments of the line.

FIGURE VIII-19. PftP Routing for Ownership Structure A1



- Structure A1 Pros:
  - Maximize opportunities for ownership involvement by all Participants.
  - Multiple, diverse owners spread investment across multiple sources.
- Structure A1 Cons:
  - Complexity of multiple players involved.
  - If segmented, risk of one segment owner withdrawing.
  - With IOU entities, PftP line cannot be located in Nebraska.
    - Unless NE power districts are involved, and the legislature agrees.

A2: Joint or Segmented Ownership limited to incumbent municipal and cooperative utilities, without IOUs (Figure VIII-20 for joint ownership all in one state or the other, Figure VIII-21 for joint ownership with a segment in NE, and Figure VIII-22 for segmented ownership).

Ownership not involving IOUs means the PftP line can be located in Nebraska or South Dakota, because Nebraska law enables locations in Nebraska. For example, public power entities and CDS Participants OPPD, Basin, MRES and SCPPA could join together to do the PftP line.

FIGURE VIII-20. Structure A2, Joint Ownership, PftP in either NE or SD

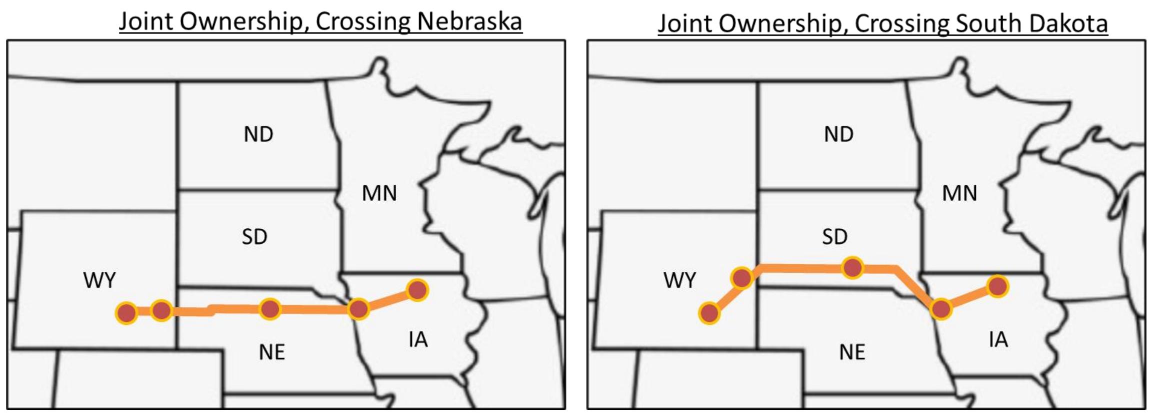


FIGURE VIII-21. Structure A2. Joint Ownership, a portion of line in NE

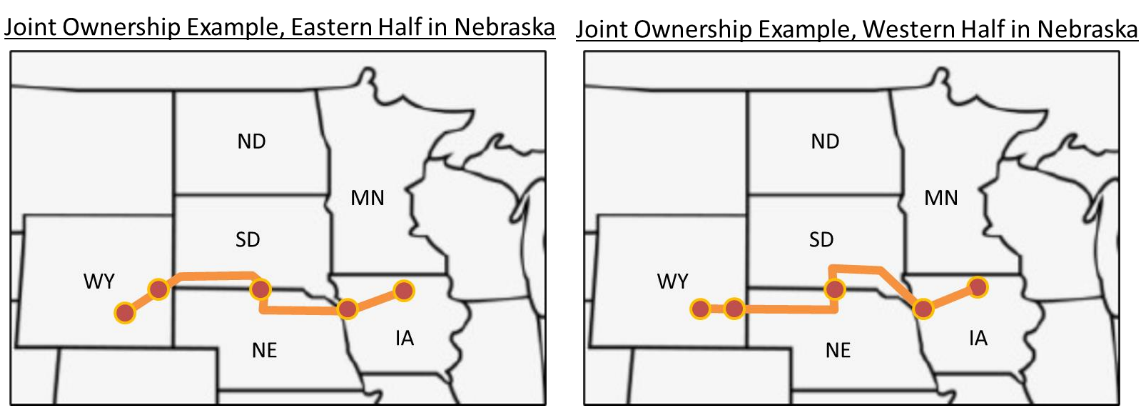
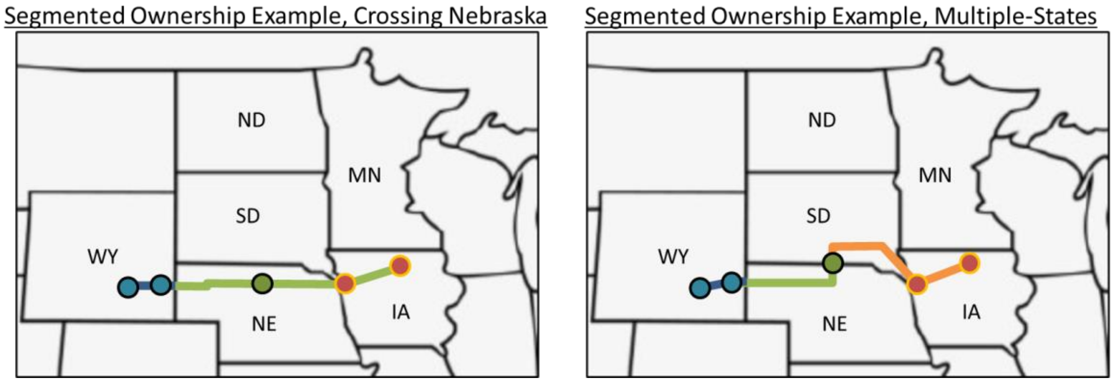


FIGURE VIII-22. Structure A2. Segmented Ownership

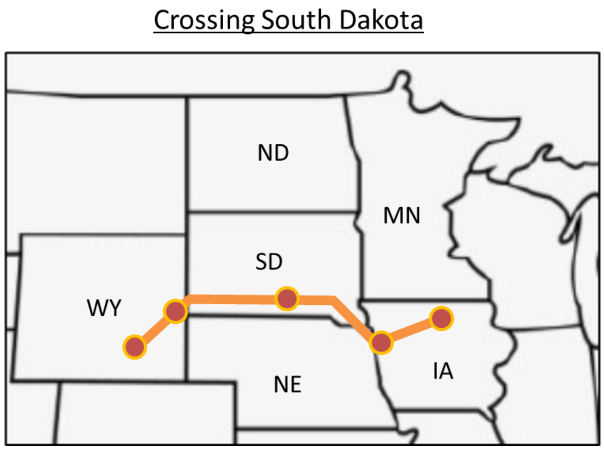


- Structure A2 Pros:
  - Enables PftP to cross NE or SD, or both.
  - Reduced complexity of organization.
    - Similar public power goals among the owners, without investor equity considerations.
  - Some reduced complexity in state regulation.
    - For PftP potion in NE, public power has authority over many of the Regulatory issues.
- Structure A2 Cons:
  - Reduced opportunity for private entities' investment.
  - If segmented risk of one segment owner withdrawing.
  - Can municipals and co-ops alone justify the entire 4,000 MW PftP?
    - Mitigate by placing a portion (not all) of PftP line in Nebraska.

B: Merchant Transmission Developer Only

Similar to Structures including IOUs, ownership involving for-profit merchants means the PftP line cannot be located in Nebraska, because Nebraska law provides only for public power ownership. (Figure VIII-23).

FIGURE VIII-23. Structure B: Merchant Developer Only



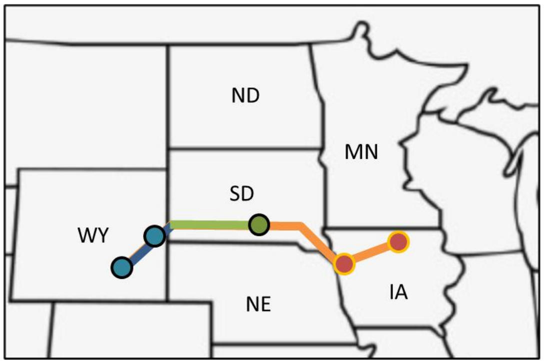
- Structure B Pros:
  - Organizational and regulatory focus and simplicity: One owner.
- Structure B Cons:
  - Limited opportunity for other CDS Participants to invest in/own PftP.
    - Can still be involved as shippers/off-takers.
  - With private ownership, PftP line cannot be located in Nebraska.
  - Risk of no or insufficient off-takers.
  - If pursued, a FERC-negotiated rate may limit opportunities to monetize the full range of PftP values.
    - Example: PftP will likely benefit regions beyond just the individual shippers or off-takers.
    - Example: Regional reliability of capacity benefits.
- Structure B Question: Can a merchant with their own affiliates potentially involved get FERC approval?
  - Answer: Yes, if the merchant secures FERC approval of their process of negotiated rates with shippers and off-takers to ensure it is fair, open and competitive.
    - Example: TransWest Express and their affiliate, Wyoming Power Company.

C1: Segmented Ownership among merchant developers and incumbent utilities including IOUs, municipals and cooperatives.

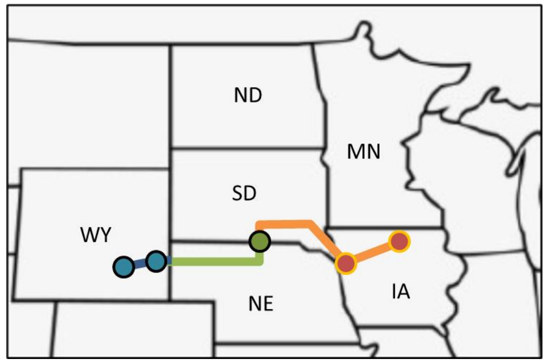
This hybrid Structure C1 combines the elements of A1 and B (Figure VIII-24).

FIGURE VIII-24. Structure C1, Merchant and Incumbent Utilities of All Types.

Hybrid Owners, SD path (Example)



Hybrid Owners, SD and NE path (Example)



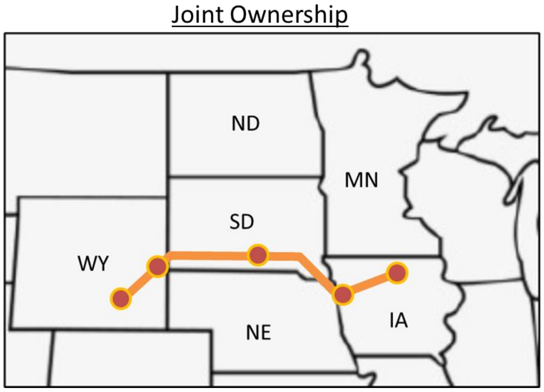
- Structure C1 Pros:
  - Similar to Structure A1.
- Structure C1 Cons:
  - Similar to Structure A1 and B.
  - If IOUs involved, cannot be located in Nebraska.
  - Merchant attracts no or insufficient off-takers.
  - Risk of withdrawal by one segment owner jeopardizing entire project.

C2: Joint or Segmented Ownership among merchant developers and incumbent utilities including IOUs only.

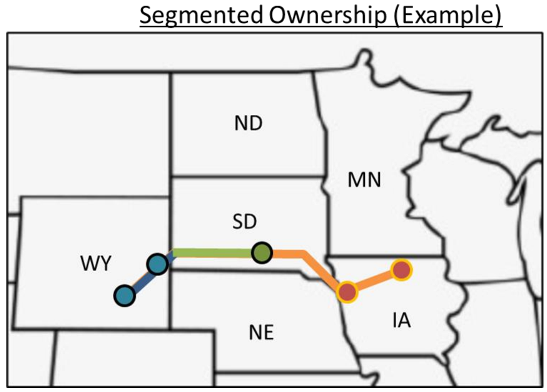
This hybrid Structure C2 combines the elements of A2 and B (Figure VIII-25).

FIGURE VIII-25. Structure C1, Merchant and Incumbent IOU Utilities Only.

Joint Ownership



Segmented Ownership (Example)

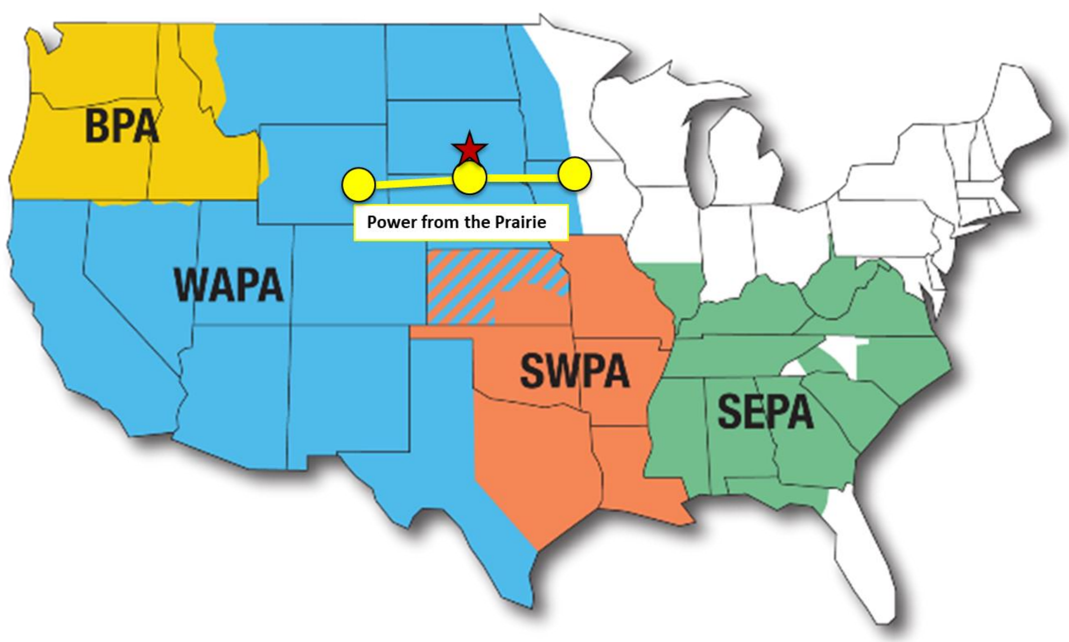


- Structure C2 Pros:
  - Similar to Structure C1.
- Structure C2 Cons:
  - Similar to Structure C1.

Potential Federal Involvement Option.

Finally, the Participants pondered whether potential Federal involvement in the PftP line ownership and/or operations would be beneficial in any of the structures listed above. For example, the Federal Power Act of 2005, Section 1222, enables such possibilities.[95] It would require involvement by the Western Area Power Administration (WAPA), and that the project be located in the WAPA service territory.

FIGURE VIII-26. Coincidence of PftP Line Route and WAPA Territory.



The PftP project would be a good fit for the WAPA territory (Figure VIII-26). The CDS Study Team initiated contacts with WAPA senior management on this topic, which indicated a potential for additional future discussions should the eventual PftP Owners be

[95] Only one such Section 1222 project has been previously proposed: The Grain Belt Clean Line from Kansas to the Tennessee Valley Authority (TVA). That Section 1222 effort was later discontinued.

interested. WAPA also has a Transmission Infrastructure Program (TIP)[96] that may be useful in future project financing.

IX. TASK 3B: REGULATORY

A. INTRODUCTION

The following regulatory considerations provide a high-level overview of our current regulatory environment. This regulatory overview does not address agency rules and practices. As the Power from the Prairie HVDC line (PftP Project) develops, this overview will likely need to be updated.

The primary regulatory issues that will affect the PftP Project are cost allocation and recovery, nondiscriminatory access to the PftP transmission line, and permits to construct the PftP Project. But first, a brief regulatory overview may be helpful.

The Federal Power Act was crafted to create a bright line between federal and state jurisdiction—giving the Federal Energy Regulatory Commission (FERC) authority to regulate the transmission of electricity in interstate commerce and wholesale sales of electricity but not matters subject to state regulation, leaving the states to regulate retail sales and intrastate activity, such as generation and the local distribution of electricity.[97]

Today, Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) coordinate the transmission system and operate wholesale electricity markets for two-thirds of the country. Because the Federal Power Act provides that FERC has jurisdiction over transmission and wholesale sales in interstate commerce, it regulates ISOs and RTOs.[98] In the rest of the country, primarily the western and southeastern United States, vertically integrated utilities operate their own transmission systems and exchanges are executed through bilateral contracts. The PftP transmission line is expected to be located in the Midcontinent Independent System Operator (MISO), Southwest Power Pool (SPP), and the West. Although there is interest in forming an RTO/ISO in the West, it does not exist today.

Most states are traditionally regulated and regulate vertically integrated utilities in which the utility owns the generation, transmission, and distribution assets. In restructured states, where retail competition is allowed, utilities are no longer vertically integrated and

[96] The WAPA Transmission Infrastructure Program (TIP) is a unique federal infrastructure financing program aimed at expanding and modernizing the electric grid. www.wapa.gov/transmission/TIP/Pages/AboutTIP.aspx
[97] 16 U.S.C. § 824(a)-(b).
[98] Note that ERCOT operates only within the state of Texas; therefore, ERCOT is regulated by the Public Utility Commission of Texas.

must purchase their generation on a merchant basis. Restructured states are generally only partially deregulated; some parts are fully regulated, and other parts are governed by new, market-oriented regimes. Note that RTOs and ISOs can serve both traditionally regulated and restructured states. It is important to note that the route for the PftP Project will be located in traditionally regulated states.

State and federal regulators often treat incumbent utilities differently than merchant developers, not because of discrimination but because the merchant business model does not always neatly conform to rules originally established for utilities. The following definitions distinguish transmission developers in the context of the regulatory environment:

Incumbent Utility Transmission Developer: A utility granted an exclusive franchise to serve retail customers within its service territory in traditionally regulated states (i.e., a monopoly) constructs a high-voltage transmission line to serve its ratepayers. An incumbent utility can be an investor-owned utility (IOU); public power district or municipal utility; or an electric cooperative or generation and transmission cooperative (G&T cooperative). In states with retail choice, the incumbent utility is the designated default service provider for retail customers who do not choose another supplier.

Merchant Transmission Developer: A third party constructs a high-voltage transmission line. Investors of a merchant project assume the full market risk of development. A merchant typically provides transmission to others as a service and does not have customer loads of its own.

Nonincumbent Utility Transmission Developer: A utility constructs a high-voltage transmission line through the service territory of an unrelated incumbent utility (typically in another state where the utility does not provide retail service). This is a type of Merchant Transmission Developer.

B. COST RECOVERY CONSIDERATIONS

1. Cost Allocation

Costs can be allocated among multiple participants through a pre-determined RTO/ISO planning process or on a voluntary basis whereby costs are allocated based on ownership shares of the transmission line.

a. Voluntary Cost Allocation

Allocating costs on a voluntary basis outside a regional planning process is a tenuous process. Each utility and merchant transmission developer has its own project investment strategy and may value benefits differently. Further, absent an approved cost allocation methodology from a regional planning organization, cost recovery from ratepayers for load serving entities (LSEs) would likely face opposition.

b. Regional Planning Cost Allocation

Transmission developers can seek *ex ante* cost allocation through the RTO/ISO planning process. If selected, the transmission project is eligible for the cost allocation method in the RTO/ISO tariff approved by FERC, which considers benefits and allocates costs across the region so that the costs are roughly commensurate with the benefits received by RTO/ISO members.

An important consideration among incumbent utility transmission developers when the transmission line spans multiple states within a region is each state will be concerned that they are paying too much for their share. Projects selected from a regional planning process essentially removes this concern.

c. Interregional Planning Cost Allocation

FERC Order 1000 is triggered when a developer of an interregional transmission project seeks cost allocation across more than one region. Adopted in 2011, Order 1000 identified criteria for approving cost allocation methodology for interregional transmission lines.[99]

The first step for the project developer would be to submit the project into the planning processes for each RTO/ISO region, or the assigned planning regions outside an RTO/ISO region, within the project footprint. If selected, planning regions can coordinate and share results of their regional transmission plans to identify any transmission projects that could then be jointly evaluated for cost allocation. If an interregional transmission project has passed these hurdles, then the six cost allocation principles would apply.

These six cost allocation principles are:

1. Costs must be allocated in a way that is roughly commensurate with benefits;
2. No involuntary allocation of costs to non-beneficiaries;
3. Benefits to cost threshold ratio must not be too high (cannot exceed 1.25 unless approval from FERC);

[99] Order No. 1000, *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, 136 FERC ¶ 61,051 (2011).

4. Allocation to be solely within transmission planning region(s) unless those outside voluntarily assume costs;
5. Transparent method for determining benefits and identifying beneficiaries; and
6. Different cost allocation methods for different types of facilities are allowed (e.g., reliability, congestion relief, state public policy).[100]

Both incumbent utility transmission developers and merchant transmission developers are eligible for cost allocation for qualifying projects. To date, no interregional transmission line has been approved for cost allocation. For the purposes of Order 1000, the planning regions applicable to PftP Project are MISO, SPP, WestConnect, and possibly Northern Grid (see Figure IX-1 below). Cost allocation can only be applied within the individual planning regions for which the project is located unless a planning region voluntarily assumes the cost. For example, CAISO could voluntarily agree to assume costs due to benefits that the PftP Project would provide to California utilities. Other planning regions within WECC's footprint could also voluntarily agree to assume costs based on the benefits to the region.

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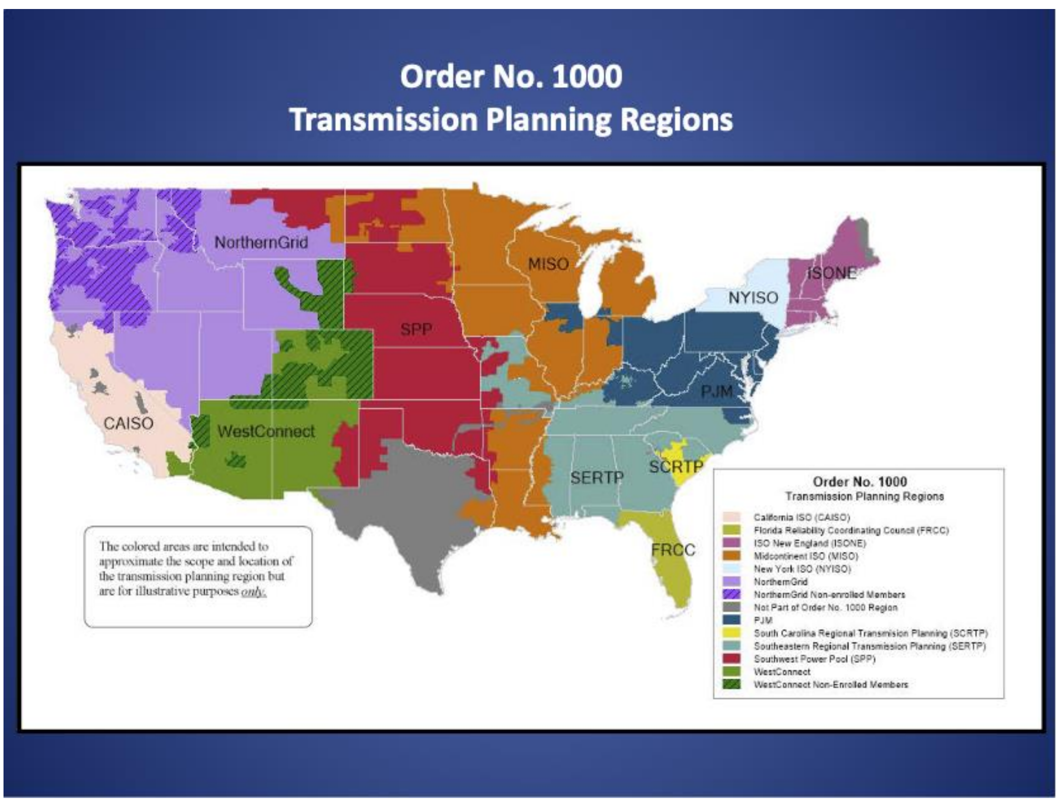
Figure IX-1. The Transmission Planning Regions



[100] *Id*. at PP 622, 637, 646, 657, 668, 685.

Note that MISO and SPP have a long-standing Joint Operating Agreement to coordinate planning and coordinate performance and functions along the seams.[101]

To allocate costs on a regional basis prior to cost recovery for an interregional transmission project, FERC action is necessary to remove existing barriers to interregional transmission planning. For example, MISO's market cost recovery model (i.e., postage stamp cost allocation method) for Multi-Value Projects (MVP), could offer valuable insight into how to develop a cost recovery model for interregional projects. MVP cost recovery is used for qualified transmission projects that produce an increase in reliability or economic efficiency, or aid in achieving state or federal public policy goals. The capital costs of MVPs are put in a special rate base and recovered from ISO participants on a regional or subregional basis. FERC has expressed interest in reforms to enhance interregional transmission development.[102]

2. Cost Recovery

a. Retail Cost Recovery for Incumbent Ownership

The process for cost recovery on capital investments among utilities is different for IOUs, cooperatives, and municipal utilities. Municipal utilities are governed by the city council or appointed utility commission. Cooperatives are nonprofit organizations owned and governed by its members who participate in setting policies and ratemaking decisions. In contrast, IOUs are governed by the state utility commission that must follow state statutes governing cost recovery for capital investments.

Merchant transmission owners cannot recover costs on the retail level because they are not load serving entities.

b. Wholesale Cost Recovery

1) Incumbent Ownership

Under section 205 of the Federal Power Act, FERC must ensure that "[a]ll rates and charges . . . by any public utility for or in connection with the transmission or sale of electric

[101] Joint Operating Agreement Between the Midcontinent Independent System Operator, Inc. and Southwest Power Pool, Inc., dated December 11, 2008.

[102] Richard Glick, Chair, Federal Energy Regulatory Commission, Press Conference Remarks (Apr. 21, 2022), https://www.ferc.gov/news-events/news/chairman-glicks-press-conference-remarks (last visited Nov. 17, 2022). A "public utility" is an entity that owns or operates facilities subject to FERC jurisdiction. 16 U.S.C. § 824(e). Note that a "public utility" is not the same as an electric utility or transmitting utility. *See* 16 U.S.C. § 976(22)-(23).

energy," and "all rules and regulations effecting or pertaining to such rates or charges" are "just and reasonable," and not unduly preferential or prejudicial.[103] As such, FERC-jurisdictional electric utilities are required to file "classifications, practices, and regulations affecting such rates and charges, together with all the contracts which in any manner affect or related to such rates, charges, classification, and services."[104] In a section 205 filing, the public utility submits a filing regarding a rate, term, or condition of a FERC-jurisdictional service or charge with FERC for approval.

The Energy Policy Act of 2005 added a new section to the Federal Power Act to direct FERC to develop incentive-based rate treatments for transmission projects. To encourage investments in transmission, FERC adopted Orders 679 and 679-A provide these incentives.[105] Orders 679 and 679-A do not explicitly grant incentives but identify specific incentives that it will allow in the context of individual declaratory orders or section 205 filings by public utilities. These incentives include: (1) return on equity (ROE) to attract capital; (2) authorization to include 100 percent of prudently incurred construction work-in-progress in the rate base and expensing of prudently incurred pre-commercial costs; (3) permission for transmission developers to base rates on hypothetical capital structures; (4) an option for accelerated depreciation for new transmission investments; (5) recovery of 100 percent of costs of abandoned transmission projects as long as costs were prudently incurred and the abandonment decision was not made by the developer; (6) for public utilities subject to retail rate moratoria, deferred cost recovery; (7) authorization to file a separate rate case for new transmission without reopening existing base rates to review and litigation; and (8) a higher ROE for transmission participating in regional RTOs and ISOs.

If the incumbent utility belongs to an RTO or ISO, the utility can submit its own section 205 filing for ROE approval or use the FERC-approved ROE on file for transmission-owning members of the RTO/ISO.

2) Merchant Ownership

Merchant developers can seek negotiated rate authority from FERC to sell transmission rights. FERC adopted a four-factor analysis to ensure against undue discrimination among potential customers of the capacity. These factors are: (1) the justness and reasonableness of rates; (2) the potential for undue discrimination; (3) the potential for undue preference, including affiliate preference; and (4) regional reliability and operational efficiency requirements.[106]

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[103] 16 U.S.C. § 824d(a).
[104] 16 U.S.C. § 824d(c).
[105] Order No. 679, *Promoting Transmission Investment through Pricing Reform*, 116 FERC ¶ 61,057 (2006), *order on reh'g*, Order No. 679-A, 117 FERC ¶ 61,345 (2006).
[106] *Chinook Power Transmission, LLC*, 126 FERC ¶ 61,134 (2009).

To prevent undue discrimination when granting negotiated rate authority, FERC reviews the terms and conditions of the merchant transmission developer's open season and its OATT commitments (or its commitment to turn operational control over to the RTO or ISO if the project is within and RTO/ISO footprint).[107] The open season "enables the merchant transmission developer to determine the extent of interest in the project, which in turn enables it to determine whether the project needs to be re-sized to fit the market."[108] FERC requires open season reports to be filed shortly after the close of the open season.[109]

FERC issued a policy statement in 2013 that clarified what would be expected of a merchant developer to pass the four-factor test, specifically the second and third factors that capacity should not be allocated in an unduly discriminatory or preferential manner.[110] FERC requires merchant transmission developers to disclose the results of their capacity allocation process and FERC will provide notice and act under section 205 of the Federal Power Act.[111]

Prior to the policy statement, FERC looked at petitioners on a case-by-case basis and required an open season. The 2013 policy statement clarified that 100 percent of the capacity can be secured through bilateral agreements negotiated directly with a subset of customers identified in the open solicitation under FERC's notice requirements.[112] As long as the criteria to evaluate potential interest in the project is transparent and not unduly discriminatory, up to100 percent of the project's capacity may be awarded to customers, including an affiliate of the developer.[113] Additionally, the merchant developer can offer disparate terms and conditions to potential customers as long as they are consistent with FERC's 2013 policy statement.[114] In contrast, FERC rejected a request by a merchant transmission developer to give preference to renewable energy resources in its open season.[115]

FERC's process to review petitions regarding capacity allocation for nonincumbent utility transmission developers will be reviewed more closely to ensure they satisfy precedent regarding cost-based transmission service under the Federal Power Act.[116]

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[107] *Id*. at P 41
[108] *Id*.
[109] *Id*.
[110] *Allocation of Capacity on New Merchant Transmission Projects and New Cost-Based, Participant-Funded Transmission Projects*, 142 FERC ¶ 61,038 (2013) [hereinafter *FERC 2013 Policy Statement*].
[111] *Id*. at P 30.
[112] *Id*. at P 16.
[113] *Id*. at P 28.
[114] *SunZia Transmission, LLC*, 160 FERC ¶ 61,074 at P 45 (2017).
[115] *Rock Island Clean Line LLC*, 139 FERC ¶ 61,142 at P 31 (2012).
[116] *FERC 2013 Policy Statement* at P 40.

3. Rate Pancaking

Interregional transmission faces another cost challenge—rate pancaking. For each transaction between adjoining Transmission Owner systems, a "point-to-point" charge is levied to exit the system and another "point-to-point" charge is levied to enter the next system. The existence of RTOs and ISOs help reduce rate pancaking because rate pancaking does not exist within their tariffs. Nevertheless, the PftP Project is expected to cross several seams and will likely be affected by rate pancaking.

C. FERC FILINGS FOR OPEN ACCESS TO TRANSMISSION

1. Incumbent

Transmission providers are required to file open access transmission tariffs (OATT) with FERC containing minimum terms and conditions of nondiscriminatory service so all generators can connect to the grid at the same price. [117] Transmission Provider means "any public utility that owns, operates, or controls facilities used for the transmission of electric energy in interstate commerce."[118]
In general, interconnection of new large scale generating facilities takes place in accordance with the transmission provider's OATT on file with FERC. As transmission providers, RTOs and ISOs have their own OATTs. If the transmission owner participates in an RTO or ISO, operational control is generally turned over to the RTO or ISO which has its own OATT on file.

When transmission facilities will be jointly operated by more than one incumbent, they can file a Joint Open Access Transmission Tariff (JOATT) with FERC. For example, Black Hills Corporation, Basin Electric, and Powder River Energy Corporation successfully filed a JOATT for their transmission facilities located in the Western Interconnection to create a "common use system" and provide open access under the JOATT.[119]

2. Merchant

Merchant transmission developers, Chinook Power Transmission, LLC (Chinook) and Zephyr Power Transmission, LLC (Zephyr) were the first merchant transmission

[117] In 1996, FERC promulgated Order 888 requiring all transmission utilities that also generate electricity to file OATTs. In 2007, FERC Order 890 amended its regulations to strengthen the *pro forma* OATT adopted in Order Nos. 888 and 889, provide greater specificity to reduce opportunities for undue discrimination, and increase transparency.
[118] 18 C.F.R. § 37.3.
[119] *Black Hills Power, Inc., Basin Electric Power Cooperative, and Powder River Energy Corporation,* 106 FERC ¶ 61,119 (2004).

developers authorized to charge negotiated rates for transmission rights.[120] Because the Chinook and Zephyr facilities were located in a region where there was no RTO or ISO, Chinook and Zephyr were required to each submit an OATT under FERC Order 890.[121]

In its 2013 policy statement, FERC reaffirmed that merchant transmission developers "become public utilities at the time their projects are energized (and, depending on the circumstances, may be public utilities even earlier)."[122] As public utility transmission providers, merchant transmission providers are subject to FERC's OATT requirements.[123] Negotiations for the allocation of initial transmission rights may address terms and conditions of the transmission service to be taken once the facilities are in service, FERC will adhere to its policy that any deviations from the *pro forma* OATT must be justified regardless of any negotiated agreement.[124]

Unlike incumbent utility transmission developers, nonincumbent utility transmission developers do not yet own or operate transmission facilities in the region that they propose to develop transmission and their OATTs serving native load are nonapplicable. FERC evaluates OATTs for nonincumbent utility transmission developers on a case-by-case basis.[125]

FERC's order authorizing negotiated rates and accepting anchor customer open solicitation for SunZia Transmission, LLC (SunZia) offers insight into how the PftP Project could be treated by FERC if PftP has multiple owners and is located, in part, outside of an RTO/ISO region. SunZia is an independent transmission developers owned by three merchant owners, SouthWestern Power Group, ECP SunZia, LLC, and Shell WindEnergy, and three utilities, Tuscan Electric Power Company, Salt River Project Agricultural Improvement and Power District, and Tri-State Generation and Transmission Association, Inc.[126] The SunZia project is located outside of an RTO/ISO region.[127]

FERC accepted SunZia's proposal that its three merchant owners file a single OATT that adheres to Order 890 prior to the commencement of service.[128] The three utilities will make their capacity shares available separately through their respective OATTs.[129] Moreover, if an RTO/ISO forms in the project's footprint, FERC expects merchant

[120] *Chinook Power Transmission, LLC*, 126 FERC ¶ 61,134 (2009).
[121] *Id*. at P 6.
[122] *FERC 2013 Policy Statement* at P 22.
[123] *Id*.
[124] *Id.* P 28.
[125] *Id*. at P. 41.
[126] *SunZia Transmission, LLC*, 160 FERC ¶ 61,074 (2017).
[127] *Id*. at P 32.
[128] *Id.* at P 37.
[129] *Id*. at PP 2, 39.

developers to turn over operational control of the line to the RTO or ISO and recover costs through a schedule in the RTO/ISO's OATT that is specific to the project.[130]

D. FEDERAL CONSIDERATIONS TO BUILD POWER FROM THE PRAIRIE

1. Federal Siting and Construction

The authority to site transmission facilities traditionally resides solely with the states, however, section 1221 of the Energy Policy Act of 2005 gave FERC authority to site transmission projects in areas that have been designated National Interest Transmission Corridors by the Department of Energy (DOE).[131] The Fourth Circuit Court of Appeals determined that FERC's siting authority in National Interest Transmission Corridors is triggered only when a state authority withholds its decision regarding approval of the permit application for more than a year.[132] With FERC's constrained authority under section 216(b), no attempts to use federal siting authority have followed the court's 2009 decision.[133]

The Ninth Circuit Court of Appeals vacated the only two designated National Interest Transmission Corridors based on the DOE's failure to adequately consider environmental impacts under the National Environmental Policy Act and solicit feedback from states.[134]

FERC issued a notice of proposed rulemaking (NOPR) on December 15, 2022, to update its regulations for siting electric transmission facilities to implement congressional directives included in the Infrastructure Investment and Jobs Act.[135] This NOPR proposes four overarching clarification and additions:

1. Clarifies FERC's authority by expressing stating that it may issue a permit for transmission facility construction or modification in a DOE-designated corridor if a state authority has denied an application.
2. Allows simultaneous process of state applications and FERC pre-filing proceedings so applicants can pursue approval before a state commission and

[130] *Chinook Power Transmission, LLC*, 126 FERC ¶ 61,134 at P 6; *SunZia Transmission, LLC*, 160 FERC ¶ 61,074 at P 46.
[131] 16 U.S.C. § 824p.
[132] *Piedmont Envtl. Council v. FERC*, 558 F.3d 304 (4th Cir. 2009).
[133] Avi Zevin et al., *Building a New Grid Without New Legislation: A Path to Revitalizing Federal Transmission Authorities*, 48 ECOLOGY LAW QUARTERLY 166, 220 (December 2020) [hereinafter *Building a New Grid Without New Legislation*].
[134] *Cal. Wilderness Coal. v. U.S. Dept. of Energy*, 631 F.3d 1072 (9th Cr. 2011).
[135] Notice of Proposed Rulemaking, *Application for Permits to Site Interstate Electric transmission Facilities*, FERC 181 ¶ 61,205 (2022); News Release, FERC, FERC Proposes Rule Implementing the Infrastructure Investment Jobs Act (Dec. 15, 2022).

FERC. If the state has not made a determination on an application one year after the commencement of FERC's pre-filing process, the state would have a 90-day window to provide comments on any aspect of the pre-filing process.

3. Requires an applicant to demonstrate it has made a good faith effort to engage with landowners and other stakeholders early in the permitting process as a precondition to exercising eminent domain authority. The proposed rule introduces a new Applicant Code of Conduct as one way to demonstrate compliance.
4. Requires the applicant to file an Environmental Justice Resource Report, a Tribal Resources Report, and an Air Quality and Environmental Noise Resource Report.[136] Information from these reports, in addition to other resource reports, will allow FERC to evaluate the effects of the proposed project under the Federal Power Act and the National Environmental Policy Act.

The DOE intends to launch a coordinated transmission deployment program to implement the Infrastructure Investment and Jobs Act, and previously enacted authorities and funding, for the Building a Better Grid Initiative.[137] The DOE also intends to conduct a Transmission Needs Study which could be used to designate National Interest Transmission Corridors.[138]

2. Federal Eminent Domain Rights

Section 1222 of the Energy Policy Act of 2005 allows the DOE to partner with transmission developers if the proposed transmission project would be constructed in the footprint of either the Western Area Power Administration or the Southwestern Power Administration.[139] This partnership allows the developer to take advantage of the power administrations' right of eminent domain.[140]

Clean Line Energy Partners LLC partnered with DOE pursuant to section 1222 for its Clean Line Plains & Eastern Transmission line, which has since been terminated.[141] This is the only project that partnered with the DOC under section 1222.[142]

[136] Presentation, FERC, Applications for Permits to Site Interstate Electric Transmission Facilities (Dec. 15, 2022).
[137] Notice of Intent for the Department of Energy, 87 Fed. Reg. 2769 at 2770 (January 19, 2022).
[138] *Id*. at 2771.
[139] 42 U.S.C. § 16421.
[140] *Building a New Grid Without New Legislation* at 199.
[141] *In re Application of Clean Lines Energy Partners LLC Pursuant to Section 1222 of the Energy Policy Act of 2005*, U.S. DEPARTMENT OF ENERGY, Summary of Findings (Mar. 16, 2016); *see Building a New Grid Without New Legislation* at 234.
[142] *Building a New Grid Without New Legislation* at 232.

3. Federal Environmental Review

Environmental review for the PftP Project may be required by the federal government in addition to state government. The level of environmental review will not be known until a route is known.

a. National Environmental Policy Act

The National Environmental Policy Act (NEPA) requires federal agencies to consider the environmental impacts of major federal actions by imposing procedural obligations.[143] Common federal actions include adoption of official policies, such as rules or regulations, adoption of formal plans, adoption of programs, and approval of specific projects. Federal environmental review is usually done jointly or concurrently with state environmental review.

The Environmental Assessment (EA) is a document prepared by the federal agency in support of its determination of whether to prepare an Environmental Impact Statement (EIS) and a Finding of No Significant Impact (FONSI). Federal agencies prepare an Environmental Impact Statement (EIS) if a proposed major federal action is determined to significantly affect the quality of the human environment. An EIS is a full disclosure document that details the process through which a project was developed, includes consideration of a range of reasonable alternatives, analyzes the potential impacts to the environment, and demonstrates compliance with other applicable environmental laws and executive orders.

NEPA plays a significant role in siting energy facilities and is often invoked by litigants to challenge energy projects. NEPA is largely a procedural statute, and the EIS process can take several years and add significant costs to the project.

An interregional transmission line, especially a major transmission project located in the West, would likely trigger NEPA due to agency involvement when federal public land or tribal land is impacted. Additionally, the project could trigger NEPA if WAPA is involved (e.g., under section 1222) or receives a loan from a federal agency.

E. STATE CONSIDERATIONS TO BUILD POWER FROM THE PRAIRIE

Each state controls its own project approval process through agency siting and judicial eminent domain proceedings, so any project spanning multiple jurisdictions depends on the coordination of multiple states. Differences in state siting procedures, including timing, present barriers and add risk to transmission lines that cross more than one state.

[143] 42 U.S.C. §§ 4321-4370.

1. State Right-of-First Refusal Laws

Several state legislatures adopted right-of-first-refusal (ROFR) laws after FERC Order 1000 directed public utility transmission providers to remove any provisions that grant a federal ROFR to build transmission facilities from their OATTs and other FERC-jurisdictional tariffs and agreements for facilities selected in a regional transmission plan for purposes of cost allocation.[144] State ROFR laws were upheld by the U.S. Court of Appeals for the Eighth Circuit in a case involving a Minnesota ROFR statute.[145]

As a result, state ROFR laws grant the incumbent utility transmission owners a ROFR to construct, own, and maintain electric transmission lines that connect to their existing facilities. While only a handful of states passed ROFR laws, the PftP Project will likely be routed through most of those states, which include Minnesota, South Dakota, Iowa, and Nebraska.[146]

It is important to note that the transmission project must be identified as needed by a regional planning authority (i.e., an RTO or ISO) to trigger state ROFR laws. Additionally, Nebraska's legislation is atypical because its regulatory framework is unique; Nebraska's ROFR applies to SPP-approved transmission projects located in Nebraska by granting the ROFR to the incumbent.[147]

State ROFR laws have the potential to impact the PftP Project if it seeks approval for cost allocation under FERC Order 1000 or some future rule that amends or replaces Order 1000 because the PftP Project would have to be selected by a regional or interregional plan thereby triggering state ROFR laws.

2. State Siting and Need Permits

a. Wyoming

1) Siting/Routing

No person may construct an industrial facility in Wyoming without a permit for the facility from the Wyoming Industrial Siting Council (ISC), which reviews socioeconomic and environmental impacts for industrial facilities, including transmission lines with a design

[144] Order No. 1000, *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, 136 FERC ¶ 61,051 at P 7. (2011).
[145] *LSP Transmission Holdings, LLC v. Sieben*, No. 18-2559 (8th Cir. 2020).
[146] *See* James J. Hoecker & Douglas W. Smith, *Regulatory Federalism and Development of Electric Transmission*, 35 Energy L.J. 71, 88-90 (May 13, 2014); Ethan Howland, *Customer Groups Seek to End Utility Lock on Transmission Development in MISO States*, Utility Dive, Jul. 25, 2022.
[147] Neb. Rev. Stat. § 70-1028.

capacity of 160 kV or greater.[148] The Wyoming Department of Environmental Quality (WDEQ) Industrial Siting Division (ISD) administers the Wyoming Industrial Development Information and Siting Act (WISA) and functions as the staff of the ISC.[149]

In summary high-voltage transmission projects, regardless of whether they are owned by incumbent utilities or merchant transmission developers, must obtain a permit from the Wyoming Industrial Siting Council to construct and operate the project unless exempt because the capacity is less than 160 kV. Although an ISC permit is not required for exempt electric transmission lines, information about the project must be submitted to the ISD.[150]

2) Certificate of Public Convenience and Necessity

Public utilities are required to obtain a Certificate of Public Convenience and Necessity (CPCN) from the Wyoming Public Service Commission (WPSC) prior to commencing construction of a transmission project.[151] A "public utility" is defined, in part, to include every person that owns, operates, leases, or controls "any plant, property or facility for the generation, transmission, distribution, sale or furnishing to or for the public of electricity for light, heat or power …."[152] Public utility also includes two or more public utilities rendering joint service.[153]

Exempt from WPSC jurisdiction is interstate commerce except when a regulatory field has not been preempted by the federal government and public utilities owned and operated by a municipality or owned and operated by a joint powers entity formed pursuant to the Wyoming Joint Powers Act.[154]

Wyoming courts have interpreted the term "public" to mean the citizenry or consumers of Wyoming.[155] The Supreme Court of Wyoming heard a condemnation case where Basin Electric Power Cooperative (Basin) was not required to obtain a CPCN because it was not a "public utility" as defined by statute. Basin supplied wholesale power to one of its distribution members that in turn sold it to its retail customers.[156]

In summary, regional transmission projects proposed in Wyoming that would not serve customers in Wyoming, would not be required to obtain a CPCN because it would not be

[148] Wyo. Stat. Ann. § 35-12-106, -119.
[149] Wyo. Stat. Ann. §§ 35-12-101 to -119; Wyo. Code R. Chapters 1-2.
[150] *See* Wyo. Stat. Ann. §§ 35-12-119(d), 35-12-109(a)(iii), (iv), (v), (viii).
[151] Wyo. Stat. Ann. § 37-2-205(a).
[152] Wyo. Stat. Ann. § 37-1-101(a)(vi)(C).
[153] Wyo. Stat. Ann. § 37-1-101(a)(vi)(J).
[154] Wyo. Stat. Ann. § 37-1-101(a)(vi)(H)(I)-(II); *see* Wyo. Stat. § 37-2-112.
[155] *Continental Pipeline Co. v. Belle Fourche Pipeline Co*., 372 F. Supp. 1333, 1335 (D. Wyo. 1974).
[156] *Bridle Bit Ranch Co. v. Basin Elec. Power Coop*., 2005 WY 108, 118 P.3d 996 (Wyo. 2005).

subject to WPSC jurisdiction. As a result, a merchant transmission developer would not need to obtain a CPCN, but an incumbent utility serving ratepayers in Wyoming would.

3) NEPA

Due to vast expanses of federal land in Wyoming, NEPA would likely be triggered. Federal land is managed by the Bureau of Land Management. For the TransWest Express Transmission Project, BLM and WAPA served as co-lead agencies for the EIS.[157]

b. Nebraska

The Nebraska Power Review Board (NPRB) regulates public power districts, rural electric cooperatives, and municipal utilities; there are no investor-owned utilities in Nebraska.[158] Proposed generation or transmission facilities must be approved by the NPRB unless those facilities are within the utility's own service territory, or the facility is a privately developed renewable energy generation facility that meets certain requirements.[159]

Private electric suppliers are expressly prohibited from selling or delivering electricity at retail in Nebraska.[160] Private electric suppliers are any electric supplier producing electricity from a privately developed renewable energy generation facility.[161] A private developer of renewable energy facility must enter into a joint transmission development agreement to connect to the transmission grid, and the utility has the right to purchase and own the transmission facilities.[162]

Transmission must be owned by the LSE for that service territory.[163] Joint transmission projects are permissible where each entity will own the portion that is located in its own service territory.[164] Surplus capacity in transmission facilities must be made available to

157 Western Area Power Administration, Transmission, Environmental review-NEPA, TransWest Express Transmission Project, https://www.wapa.gov/transmission/EnvironmentalReviewNEPA/Pages/transwest-express-nepa.aspx (last visited November 14, 2022).
158 Neb. Rev. Stat. §§ 70-1001 to -1028.
159 Neb. Rev. Stat. § 70-1012; *see* Neb. Rev. Stat. § 70-1014.02. For a generation facility proposed by an incumbent utility to be exempt from NPRB approval, the generation facility or transmission capacity must not supply wholesale power customers outside the applicant's existing retail service area or chartered territory. Neb. Rev. Stat. § 70-1012(1)(b)(iii).
160 Neb. Rev. Stat. § 70-1014.02(7).
161 Neb. Rev. Stat. § 70-1001.01.
162 Nev. Rev. Stat. § 70-1014.02(2)(a)(iv), (2)(c).
163 State policy requires that electric transmission facilities and interconnections "will be provided and made available to all power agencies so as to result in the lowest possible cost for the transmission and delivery of electric energy over the transmission and interconnected facilities of any public power district, public power and irrigation district, individual municipality, group of municipalities registered with the Nebraska Power Review Board, governmental subdivision, or nonprofit electric cooperative corporation." Neb. Rev. Stat. § 70-625.02.
164 Neb. Rev. Stat. § 70-1012; *see* § 70-628.01. NPRB issued a guidance document for joint projects.

any Nebraska power agency.[165] As a political subdivision, municipal utilities, including public power districts, are prohibited from owning stock or having an ownership interest in a private corporation or providing a loan to a private corporation.[166]

To receive approval from the NPRB, the applicant for a generation or transmission facility must provide sufficient evidence to allow the NPRB to make the following findings: the application will serve the public convenience and necessity, the applicant can most economically and feasibly supply the electric service from the proposed facility (i.e., the "lowest cost standard"), and the proposed facility would not unnecessarily duplicate existing facilities or operations.[167] Costs are an important factor in the approval process and the applicant must demonstrate how ratepayers would benefit from the facility.

Regional transmission lines must have been approved for construction by a regional transmission organization transmission plan prior to seeking approval by the NPRB.[168] If the incumbent utility of the existing transmission facilities to which the transmission line will connect fails to provide notice to the NPRB to construct the transmission line, the incumbent utility surrenders its first right to construct, own, and maintain the transmission line and any other incumbent transmission owner may file an application.[169]

Constructing generation and transmission facilities in the Nebraska Sandhills present challenges due to habitat for migratory birds, priceless archaeological sites, and visible pioneer wagon train ruts and swales.

c. South Dakota

To construct transmission facilities greater than 115 kV in South Dakota, the applicant must obtain a permit to construct the energy facility from the South Dakota Public Utilities Commission (SD PUC).[170] The decision on need and routing are combined within this single permit. SD PUC requires an energy facility permit. South Dakota Codified Laws Chapter 49-41B and Administrative Rules of South Dakota Chapter 20:10:22 govern the permitting process that applies to both incumbent utility transmission developers and merchant transmission developers.

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[165] Neb. Rev. Stat. § 70-626.03.
[166] Neb. Const. Art. X1, section 1; Art. XIII, section 3; *State ex rel. Johnson v. Consumers Pub. Power Dist*., 143 Neb. 753, 10 N.W.2d 784 (Neb. 1943); Final Report Nebraska Legislature L.R. 455 Phase II Study, prepared by Ridley and Associates, at 7.4.1 (December 1999).
[167] Nev. Rev. Stat. § 70-1014.
[168] Nev Rev. Stat. § 70-1028.
[169] Nev Rev. Stat. § 70-1028.
[170] S.D. Codified Laws § 49-41B-4. The definition of "transmission facility" has two exceptions for lines greater than 115 kV that would not apply to the PftP Project. S.D. Codified Laws § 49-41-2.1

The SD PUC will consider the applicant's compliance with relevant laws, the proposed project's potential environmental, social, and economic impacts in the proposed project's area, and the health, safety, and welfare of residents.[171] The SD PUC must decide whether to grant the permit to construct the proposed energy facility within twelve months of receiving the application.[172]

The PftP Project would most likely be considered a "trans-state transmission facility," defined as:

> an electric transmission line and its associated facilities which originates outside the State of South Dakota, crosses this state and terminates outside the State of South Dakota; and which transmission line and associated facilities delivers electric power and energy of twenty-five percent or less of the design capacity of such line and facilities for use in the State of South Dakota.[173]

Not only must a trans-state transmission facility obtain a permit from the SD PUC, it must also receive approval by an act from the South Dakota Legislature.[174] The requirement for legislative approval is likely why it appears there has been only one trans-state transmission facility proposed in South Dakota. In that case, the SD PUC denied a permit for the MANDAN trans-state transmission facility (MANDAN is an acronym for Manitoba, Dakotas, and Nebraska) proposed by the Nebraska Public Power District in 1982.[175]

A trans-state transmission facility must meet specified criteria in addition to the requirements described above for transmission lines. The proposed trans-state transmission route must not interfere with the "orderly development of the regions with due consideration having been given to views of the governing bodies of the effective local units of government."[176]

Another requirement has been found to be unconstitutional by the South Dakota Supreme Court. South Dakota Codified Law 49-41B-4.2(5) requires that the proposed trans-state transmission facility be "consistent with the public convenience and necessity in any area

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[171] S.D. Codified Laws § 49-41B-22; SDCL § 49-41B-4.2.
[172] S.D. Codified Laws § 49-41B-24.
[173] S.D. Codified Laws § 49-41B-2(11).
[174] S.D. Codified Laws § 49-41B.4.1. The primary intent of this law is likely to protect the state from becoming "flyover land" for a transmission project without providing benefits to the state. The law does not consider additional economic benefits from a project such as PftP, including unlocking renewable energy resources from a constrained system for export.
[175] *In re the Applicant of Nebraska Public Power Dist. for a Permit to Construct and Operate Proposed Mandan Nominal 500 KV Transmission Facility*, 354 N.W.2d 713, 715 (S.D. 1984)
[176] S.D. Codified Laws § 49-41B-4.2(4).

or areas which will receive electrical service, either direct or indirect, from the facility, regardless of the state or states in which area or areas are located." The South Dakota Supreme Court found this requirement effectively places a burden on interstate commerce thereby violating the commerce clause.[177] Further research would be needed to determine why this requirement remains included in the South Dakota Code. One possibility could be a narrow interpretation of the decision.

An Environmental Impact Statement (EIS) may be required by the SD PUC, pursuant to South Dakota Codified Law Chapter 34A-9, based on the type of proposed project.[178]

d. Iowa

1) Transmission Line Franchise

Incumbent utility transmission developers and merchant transmission developers must obtain a franchise from the Iowa Utilities Board (IUB) to construct transmission lines greater than 69 kV located outside a city.[179] The applicant must include the route and possible alternative routes of the proposed project.[180] By definition, a "merchant line" is a "high-voltage direct current electric transmission line which does not provide for the erection of electric substations at intervals of less than fifty miles, which substations are necessary to accommodate both the purchase and sale to persons located in [Iowa] of electricity generated or transmitted by the franchisee."[181]

Before granting a franchise, the IUB must find that the "proposed line or lines are necessary to serve a public use and represents a reasonable relationship to an overall plan of transmitting electricity in the public interest."[182] The duration of the franchise is limited to 25 years.[183] Before the 25-year franchise expiration date, the company would have to file a petition for an extension (renewal) of the franchise with the IUB.[184]

The IUB must consider granting a franchise in each county where the petitioner proposes the transmission line. For example, if the proposed transmission line will cross fifteen counties, then the applicant must file fifteen franchise petitions (i.e., one petition per county). In which case, the IUB would create a master docket to receive all pleadings,

[177] *In re the Applicant of Nebraska Public Power Dist. for a Permit to Construct and Operate Proposed Mandan Nominal 500 KV Transmission Facility*, 354 N.W.2d 713, 718 (S.D. 1984) (referring to SDCL 49-41B-22(5), which contained identical language to 49-41B-4.2(5)).
[178] S.D. Codified Laws § 49-41B-21.
[179] Iowa Code § 478.1(1).
[180] Iowa Code § 478.2.
[181] Iowa Code § 478.6A(1).
[182] Iowa Code § 478.4.
[183] Iowa Code § 478.9.
[184] Iowa Code § 478.13; Iowa Admin. Code r. 199-11.8.

motions, and other filings that apply to all fifteen dockets. Alternatively, the applicant can file a petition to combine the separate county franchises into a single franchise for the entire transmission line. The IUB does not have siting authority regarding transmission lines that run inside of city limits. Each affected city must grant a franchise to the applicant.

A hearing is held upon the filing of objections or when a petition involves the taking of property under the right of eminent domain, which would take place in the county seat of the county located at the midpoint of the proposed transmission line.[185] The franchise hearing uses a formal, evidentiary process and may be conducted by an administrative law judge or the IUB.[186]

e. Minnesota

1) Certificate of Need

In Minnesota, the definition of a large energy facility, as defined in Minnesota Statutes section 216B.2421, include high-voltage transmission lines, which trigger a Certificate of Need (CN).[187] A CN is a document issued by the Minnesota Public Utilities Commission (MPUC) that shows there is a need for the power produced.[188] A CN is needed to build a large energy facility unless the applicant can show that the demand for the electricity cannot be met more cost effectively by other measures. There are exemptions to the requirement listed in statute.

There are two methods used for the review of CN applications: informal review process and contested case. Most CN applications are examined using the informal review process; however, a contested case would likely be ordered by the MPUC if there is a known controversy or there are issues about the project that should be examined more closely. Contested cases are a formal, evidentiary process under the Minnesota Administrative Procedure Act process and an Administrative Law Judge is assigned.[189] Regardless of whether the HVTL was proposed by an incumbent utility transmission developer or a merchant transmission developer, a CN would be required as long as the HVTL meets the definition of a "large energy facility."

[185] Iowa Code § 478.6.
[186] Iowa Code § 478.4. Additional information can be found in IUB's website, https://iub.iowa.gov/sites/default/files/documents/2018/09/brochure_franchises_1.pdf (last visited November 15, 2022).
[187] Transmission lines with a capacity less than 200 kV are excluded unless they are 100 kV or greater with more than ten miles in length or cross a state line. Minn. Stat. § 216B.2421, subds. 2(2), 2(3).
[188] Minn. Stat. § 216B.243.
[189] Minn. Stat. ch. 14.

2) *Route Permit*

Under the Minnesota Power Plant Siting Act, a route permit would be required.[190] There is an alternative review process for route permits under certain circumstances that would not likely be applicable to the PftP Project unless at least 80 percent of the distance of the line in Minnesota would be located along existing HVTL right-of-way.[191] The alternative review process takes approximately six months to complete and requires an Environmental Assessment.[192] The full permitting process takes approximately one year to complete and requires and Environmental Impact Statement.[193]

3. Eminent Domain

In general, incumbent utilities have the ability to exercise eminent domain while merchant transmission developers do not. Nonincumbent utilities located within the state will likely have eminent domain authority if the project serves a public use or purpose. States typically require that the transmission project serve a public use or public purpose. State statutes that grant eminent domain authority to "utilities," "power companies," or similar entities, could be interpreted to include merchant transmission developers if they are defined broadly.[194]

Nebraska explicitly bans merchant transmission developers; however, eminent domain may be available to merchant transmission developers in South Dakota, Wyoming, and Iowa, but the law is unclear.[195] Eminent domain authority is unlikely for merchant transmission developers in Minnesota.[196] Generally, merchant transmission developers claiming eminent domain authority would likely face legal challenges.

a) Wyoming

Under the Wyoming Eminent Domain Act, eminent domain is granted to public utilities and private companies for the construction and maintenance of transmission lines.[197] Further, "[n]o person shall institute a condemnation proceeding relating to any facility for

[190] Minn. Stat. ch. 216E.
[191] Minn. Stat. § 216E, subds. (1)-(2).
[192] *See* Minn. R. ch. 7850.
[193] *See id*.
[194] Alexandra B. Klass, *Takings and Transmission*, 91 N.C. L. Rev. 1079 at 1126 (2013), https://scholarship.law.umn.edu/faculty_articles/.
[195] *Id*.
[196] Alexandra B. Klass & Jim Rossi, *Addressing the Regulatory Holdout Problem in the Siting of Transmission Lines*, STATE POWER PROJECT: POLICYMAKER SUMMARY (2015) https://statepowerproject.files.wordpress.com/2015/05/transmissionpolicypaper.pdf (last visited November 16, 2022).
[197] Wyo. Stat. Ann. § 1-26-815(a).

which a certificate of public necessity and convenience is required until the certificate has been issued."[198] Because a CNPN is generally not required for a merchant transmission developer because it is not regulated by the WY PSC, the door is left open for interpretation that a merchant transmission developer could exercise eminent domain as long as the requirements to exercise eminent domain are met.[199]

In 2005, the Supreme Court of Wyoming held that a non-public power company can exercise eminent domain without a CPCN as long as it can demonstrate public interest and necessity as required by Wyoming Statutes section 1-26-504(a)(i) where the need for additional electric power to the energy corporation's service territory and that additional power would inure to the benefit of the public in that locality, both in terms of the additional power itself and the reliability of service in the area are demonstrated.[200]

b) Nebraska

Only consumer-owned electric suppliers operating in Nebraska (i.e., public power districts, cooperatives, and municipalities) may exercise eminent domain to acquire land to construct transmission lines and related facilities.[201] Private electric suppliers are expressly prohibited from exercising eminent domain.[202]

c) South Dakota

A "utility" constructing a trans-state transmission line is entitled to the power of eminent domain as long as it has obtained a permit pursuit to South Dakota Codified Law chapter 49-41B and legislative approval pursuant to South Dakota Codified Law section 49-41B-4.1.[203]

An "electric utility" is defined as "any person operating, maintaining, or controlling in this state, equipment or facilities for providing electric service to or for the public including facilities owned by a municipality."[204]

A definition for "utility" can be found in South Dakota Codified Law chapter 49, as it relates to a "utility crossing of a railroad right-of-way." Here, a "utility" is defined as an "electric

[198] Wyo. Stat. Ann. § 1-26-816.
[199] Wyo. Stat. Ann. § 1-26-504. Depending on ownership structure, some exceptions could apply. See Section IX.E.2.a.2) above.
[200] *Bridle Bit Ranch Co. v. Basin Elec. Power Coop.*, 2005 WY 108, 118 P.3d 996 (Wyo. 2005).
[201] Neb. Rev. Stat. §§ 70-1014.02(6); 70-301.
[202] Neb. Rev. Stat. § 70-1014.02(5).
[203] S.D. Codified Laws § 21-35-1.1; *see also* § 49-41B-4.4 (addressing eminent domain acquisition of fee interest in land outside of right-of-way for trans-state transmission facilities).
[204] S.D. Codified Laws § 49-34A-1(7).

utility, public utility, gas utility, municipal utility, municipal power agency, joint action agency, consumers power district, pipeline company, telecommunications company, and rural water system."[205] The South Dakota Supreme Court applied the definition of "utility" broadly to include an electric cooperative for the purposes of eminent domain authority.[206]

In a South Dakota Supreme Court case, landowners argued that two utilities obtained easements to construct a 163-mile transmission line across South Dakota and connect in North Dakota were unnecessary because the transmission line would not serve a public purpose.[207] The court rejected the landowners' challenge and found the utilities could exercise eminent domain because the project was selected in MISO's regional planning process for the benefit of the public.[208]

d) Iowa

The IUB has discretion to grant eminent domain rights. As long as a franchise has been secured from the IUB, the franchisee has the right of eminent domain to the extent approved by the IUB.[209] Therefore, it is possible for merchant transmission developers to obtain eminent domain rights. Regardless, the franchise applicant cannot begin negotiating and purchasing easements prior to the required informational meetings.[210]

e) Minnesota

Under Minnesota's eminent domain law, "public service corporation" is a utility as defined by Minnesota Statutes section 216E.01,[211] which defines "utility" as "any entity engaged or intending to engage in this state in the generation, transmission, or distribution of electric energy including, but not limited to, a private investor-owned utility, cooperatively owned utility, and a public or municipally owned utility."[212]

Additionally, a "public service corporation" is a "gas, electric, telephone, or cable communications company; cooperative association; natural gas pipeline company; crude oil or petroleum products pipeline company; municipal utility; municipality when operating its municipally owned utilities; joint venture created pursuant to sections 452.25 or 452.26; or municipal power or gas agency."[213]

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[205] S.D. Codified Laws § 49-16A-100.2.
[206] *Basin Elec. Power Coop. v. Payne*, 298 N.W.2d 385, 386 (S.D. 1980).
[207] *Montana-Dakota Utilities Company v. Park-shill Farms*, 905 N.W.2d 334, 336 (S.D. 2017).
[208] *Id*. at 339.
[209] Iowa Code § 478.15.
[210] Iowa Code § 478.2(4).
[211] Minn. Stat. § 117.025, subd. 10.
[212] Minn. Stat. § 216E.01, subd. 10.
[213] Minn. Stat. § 117.025, subd. 10.

In a 2012 order for a route permit, the Minnesota Public Utilities Commission explicitly stated that the renewable energy developer would not have eminent domain authority for a transmission line for interconnection to the developer's wind farm.[214]

4. Renewable Portfolio Standards and Clean Energy Standards

Renewable Portfolio Standards (RPS) generally count generation resources such as wind, solar, biomass, geothermal, and some hydroelectric facilities based on size and vintage year as eligible for compliance. Clean Energy Standards (CES) generally include resources that have zero emissions. Statutory definitions of "renewable" and "clean" vary from state to state.

States where the PftP transmission line will be located either do not have an RPS or CES, have exceeded statutory goals and requirements, or are on track to meet statutory goals and requirements. An exception, however, is Minnesota's recently enacted carbon-free electricity standard, which requires that 100 percent of its electricity will be carbon free by 2040.[215] The new law also requires that at least 55 percent of total retail electric sales in Minnesota must be generated from eligible renewable energy resources by 2035.[216] This new legislation is expected to create new opportunities for clean energy investments.

The demand for renewable energy remains strong in the Midwest regardless of state standards. For example, MidAmerican Energy's GreenAdvantage® program allows customers in Iowa to claim a verified renewable energy amount. In 2021, that amounted to 88.5% of the Iowa's retail load.[217] Moreover, MidAmerican Energy has a goal to reach net-zero greenhouse gas emissions by 2050. South Dakota produced more than 52% of its electricity from wind generation in 2021, resulting in a need to export wind energy to nearby states.[218]

One of the many aspects that makes the PftP Project unique is its ability to help California meet its renewable energy requirements and zero-carbon emissions goals despite its

[214] *In re Prairie Rose Transmission, LLC*, Minn. P.U.C. Docket No. IP-6838/TL-10-134, Findings of Fact, Conclusions of Law, and Order at (Jan. 13, 2012).
[215] Press Release, Office of Governor Tim Walz and Lt Governor Peggy Flanagan, Governor Walz Signs Bill Moving Minnesota to 100 Percent Clean Energy by 2040 (Feb. 7, 2023), https://mn.gov/governor/news/?id=1055-563453 (last visited Feb. 28, 2023).
[216] *Id.*
[217] MidAmerican Energy Company, GreenAdvantage, https://www.midamericanenergy.com/green-advantage (last visited Dec. 28, 2022).
[218] Joshua Hsiar, *Wind is Now South Dakota's No. 1 Producer of Electricity, But Not Every Day,* Energy News Network

midwestern location. A recent report concluded significant investments in new and existing technologies will be needed to reach California's goals.[219]

F. OUT-OF-STATE RENEWABLE ENERGY GENERATION ELIGIBLITY FOR CALIFORNIA RPS AND CES

1. California RPS and CES

California's RPS requires all electric LSEs to procure 60 percent of their electricity portfolio from eligible renewable energy resources by 2030.[220] California also established a target of 100 percent zero-carbon resources by 2045.[221]

The California Public Utilities Commission (CPUC), California Energy Commission (CEC), and the California Air Resources Board (CARB) implement and enforce California's RPS. Note that publicly owned electric utilities (POUs) are treated differently than IOUs. The CEC has statewide jurisdiction while the CPUC has jurisdiction over investor-owned utilities (IOUs) and other privately owned retail sellers of electricity such as community choice aggregators. As a result, the CEC determines RPS compliance for POUs and the CPUC determines compliance for privately owned retail sellers of electricity. The CEC is responsible for verifying renewable energy procurement for all RPS participants.

Other key entities in this regulatory schematic are balancing authorities, such as the California Independent System Operator (CAISO) and Los Angeles Department of Water and Power; Western Electricity Coordinating Council (WECC), which is responsible for coordinating and promoting reliability of the bulk electric system under delegated authority from the North American Electric Reliability Corporation (NERC); and the Western Renewable Energy Generation Information System (WREGIS), which is responsible for tracking renewable energy attributes for the region covered by WECC.

2. Eligibility of Out-of-State Renewable Energy

The PftP Project has the potential to deliver the clean energy resources California needs to meet its statutory requirements, however, accounting for renewable energy generated in the Midwest from a regulatory perspective poses challenges. Renewable energy generated in the Midwest was not considered when the California's regulatory framework was established. As a result, some changes may be needed. The CEC guidebook,

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[219] Press Release, California Energy Commission, California Releases Report Charting Path to 100 Percent Clean Electricity (Mar. 15, 2021), https://www.energy.ca.gov/news/2021-03/california-releases-report-charting-path-100-percent-clean-electricity (last visited Dec. 28, 2022).
[220] Cal. Pub. Util. Code §§ 399.11-399.32.
[221] Cal. Health & Safety Code § 38562.2.

Renewable Portfolio Standard Eligibility (CEC Guidebook), provides a good starting point to understand how renewable energy generated outside California could be counted as RPS-eligible facilities.[222]The CEC Guidebook addresses the requirements and processes for certifying facilities and compliance verification.

As addressed in chapter three of the CEC Guidebook, RPS eligibility requirements for facilities govern the operations, location, and other characteristics of the facility. To qualify as a facility for POU RPS compliance, the facility must have an e-Tag containing the details of the transaction to transfer energy across the transmission grid from a source point (i.e., the generating facility) to a sink (i.e., the balancing authority where the electric load is located).[223] The longer the sink path, the more difficult it will be to demonstrate the transaction for compliance, which can also substantially lengthen the process for regulatory approval. These requirements pose a challenge for facilities that intend to market to California by interconnecting to the PftP transmission line.

Processes exist to verify scheduled delivery for certain facilities not interconnected to a California balancing authority.[224] As applied to POUs, CEC staff verifies that procurement satisfies the scheduling requirements of the RPS regulations by reviewing the e-Tag data.[225] Additionally, in most cases, renewable energy credits (RECs) would be procured bundled (i.e., electricity plus associated RECs) and the electricity would be scheduled on an hourly or sub-hourly basis whereby the electricity cannot be substituted from another source; therefore, energy losses must be subtracted from the generation.[226] The applicability of various regulatory processes is too complex to describe in this overview, however, pathways currently exist to transfer renewable energy from the Midwest to California under many scenarios.

Eligibility requirements also vary depending on the type of facility. For example, energy storage facilities, including pumped hydroelectric storage, are not inherently renewable. To be considered an eligible renewable facility, the qualifying renewable energy facility must be integrated or directly connected to the energy storage facility such that only

[222] CAL. ENERGY COMM'N., RENEWABLE PORTFOLIO STANDARD ELIGIBILITY COMMISSION GUIDEBOOK (9th ed. Jan. 2017).
[223] *Id*. at 64. Note that these e-Tag data requirements are additional requirements placed on POUs. *Id*.
[224] CAL. ENERGY COMM'N., RENEWABLE PORTFOLIO STANDARD VERIFICATION METHODOLOGY REPORT (2nd ed. Oct. 2018). A "California Balancing Authority" is defined as a "balancing authority primarily located in California with more than 50 percent of its end-use electric load physically located within the political boundaries." Cal. Code Regs. Tit. 20, § 3201(f).
[225] *Id*. at 16. There are two processes for submitting e-Tag data; one process when e-Tags are tracked in WREGIS and another when e-Tags are not available in WREGIS. *Id*.
[226] Id. at 15.

renewable energy can be stored. Additionally, energy losses from energy storage must be subtracted from the generation.[227]

In summary, the PftP Project has the potential to unlock thousands of megawatts of renewable energy for use in the California market—making PftP an attractive investment. Streamlining California's regulatory process to better accommodate renewable energy from the Midwest would help make the California market and the PftP Project more attractive to renewable energy developers.

G. RENEWABLE ENERGY GENERATION AND STATE ECONOMIC BENEFITS

Although not included in the direct benefit economic analysis of the CDS, a major infrastructure development like Power from the Prairie and the Gregory County Pumped Storage Project would also have indirect benefits for the states involved.

In addition to indirect project benefits, including economic development and jobs, states would stand to gain significant state production tax benefits from added generation of wind and solar resources for export. The following is a state-by-state summary[228] of tax incentives in states likely affected by the PftP transmission route:

1. Wyoming

A tax of $1.00 per Megawatt-hour is levied on the production of electricity produced from wind resources on or after Jan. 1, 2012. The tax is imposed on each megawatt hour of electricity produced, at the point of interconnection with an electric transmission line. Electricity produced from a wind turbine shall not be subject to the tax imposed until three years after the turbine first produced electricity for sale.

2. Nebraska

Nebraska has a policy to encourage and allow opportunities for development and operation of renewable energy facilities intended primarily for export from the state in a manner that protects the ratepayers of consumer-owned utility systems operating in the state from subsidizing the costs of such export facilities through their rates and that results

[227] CAL. ENERGY COMM'N., RENEWABLE PORTFOLIO STANDARD ELIGIBILITY COMMISSION GUIDEBOOK 40-41 (9th ed. Jan. 2017).
[228] With the exception of Nebraska, the summary of state incentives was derived from the Memorandum from the Wyoming Legislative Service Office on the Taxation of Power Generation to the Joint Revenue Committee (Jul. 5, 2019), https://www.wyoleg.gov/InterimCommittee/2019/03-20190708July52019RevenueCommitteerevisedmemoelectricityproductiontaxes.pdf (last visited Mar. 6, 2023).

in economic development and employment opportunities for residents and communities of the state.[229]

3. South Dakota

Wind farms first producing power after June 30, 2007, or solar facilities, with capacities of 5 MW or more, shall pay an annual tax of $3.00/kW times the nameplate capacity of the renewable facility. The tax is imposed beginning the first calendar year the renewable facility generates gross receipts. Wind farms producing power for the first time after March 31, 2015 shall pay an annual tax of $0.00045/kWh of electricity produced. Solar facilities shall pay an annual tax of $.00090/kWh of electricity produced by the solar facility.

The taxes described above are in lieu of all taxes levied by the state, counties, municipalities, school districts, or other political subdivisions on the personal and real property of the company which is used or intended for use as a renewable facility. These taxes are not in lieu of the retail sales and service taxes imposed.

4. Iowa

A replacement generation tax of 0.06 cents/kWh is imposed on electricity generated, except electricity from the following:

- Low-capacity factor electrical generating plants
- Qualifying facilities owned or leased by a municipal utility
- Qualifying wind energy conversion property
- Qualifying methane gas conversion property
- Facilities owned by or leased by a state university and consumed exclusively by such university
- On-site facilities owned by or leased to a self-generator.

In lieu of the tax imposed on electricity generated from hydroelectric plants with capacity of 100 MW or more, a replacement generation tax of 0.1847 cents/kWh is levied. In lieu of the tax imposed on electric companies with joint interest in a generating plant and joint interest in less than five pole miles of transmission lines, a replacement generation tax of 0.1099 cents/kWh is imposed.

[229] Neb. Rev. Stat. § 70-1030.

5. Minnesota

a. Wind Energy Conversion System (WECS)

A tax is levied on the production of electricity from a wind energy conversion system installed after Jan. 1, 1991, and used as an electric power source at the following rates:

- 0.12 cents/kWh for a large-scale conversion system (more than 12 MW)
- 0.036 cents/kWh for a medium-scale system (over 2 MW and not more than 12 MW)
- Tax does not apply to electricity produced by WECS located in job opportunity building zones. All real and personal property of a WECS is exempt from property tax except that the land on which the property is located remains taxable.

b. Solar Energy Generation

A tax of $1.20/MWh is levied on the production of electricity from a solar energy generating system used as an electric power source with a capacity exceeding one megawatt. Personal property consisting of solar energy generating systems is exempt from property tax. Solar energy systems, as defined, are exempt from sales tax.

H. THE PftP INTERREGIONAL TRANSMISSION ORGANIZATION (ITO) CONCEPT

As described in Section VII of this report, the ITO is currently a concept because interregional transmission lines designed to move electricity in a bi-directional manner across the United States currently do not exist. Under its jurisdictional authority provided by the Federal Power Act, FERC would have to approve the ITO concept.

FERC's past rulemaking orders regarding RTOs provide insight into what it may need to approve the ITO concept. FERC encouraged the formation of RTOs in FERC Order 2000 on a voluntary basis because it thought they could: (1) improve efficiencies in transmission grid management; (2) improve grid reliability; (3) remove remaining opportunities for discriminatory transmission practices; (4) improve market performance; and (5) facilitate lighter handed regulation.[230] Order 2000 also established minimum characteristics and functions for an RTO.[231]

The four minimum characteristics for an RTO are:

[230] Order No. 2000, *Regional Transmission Organizations*, 89 FERC ¶ 61,285 (1999).
[231] *Id*.

- Independence from market participants;
- Appropriate scope and regional configuration;
- Possession of operational authority for all transmission facilities under the RTO's control; and
- Exclusive authority to maintain short-term reliability.

The minimum functions of an RTO are:

- Tariff Administration and Design
- Congestion Management
- Parallel Path Flow
- Ancillary Services
- OASIS and Total Transmission Capability (TTC)
- Available Transmission Capability (ATC)
- Market Monitoring
- Planning and Expansion
- Interregional Coordination

FERC not only approved the voluntary creation of RTOs, but also ISOs, transcos, or a hybrid form as long as the RTO meets FERC's minimum characteristics and functions.[232] FERC did not want to limit the flexibility of proposed structures for RTOs.[233] FERC Order 2000 provides a foundation to create the ITC concept.

I. THE FEDERATION POWER MARKETER CONCEPT

As described in Section VII.C.3, the Federation would be an interregional HVDC-based, wholesale transaction aggregator. The Federation, as an entity, would not own or control generation or transmission facilities in any region, although it may be affiliated with an entity that does own generation or transmission. The function of the Federation would be to aggregate and sell time-diversified generation resources on an interregional basis under its FERC-approved market-based rate authority for sales of electric energy, capacity, and ancillary services on a wholesale basis.

FERC Order 697 created two categories of wholesale power marketers: Category 1 and sellers who do not fall into Category 1 are designated as Category 2 sellers. Category 1 sellers are:

[232] *Id*. at p. 124.
[233] *Id*.

> wholesale power marketers and wholesale power producers that own or control 500 MW or less of generation in aggregate per region; that do not own, operate, or control transmission facilities other than limited equipment necessary to connect individual generation facilities to the transmission grid (or have been granted waiver of the requirements of Order No. 888); that are not affiliated with anyone that owns, operates, or controls transmission facilities in the same region as the seller's generation assets; that are not affiliated with a franchised public utility in the same region as the seller's generation assets; and that do not raise other vertical market power issues. Category 1 sellers are not required to file regularly scheduled updated market power analyses.[234]

Unlike Category 1 sellers, Category 2 sellers must file regularly scheduled updated power market analyses.[235] FERC, however, can request power market analysis of from any Category 1 or Category 2 seller at any time.[236]

Prior to Order 697, FERC developed a four-prong analyses to assess whether a seller should be granted market-based rate authority: (1) whether the seller and its affiliates lack, or have mitigated, market power in generation; (2) whether the seller and its affiliates lack, or have mitigated, market power in transmission; (3) whether the seller and its affiliates can erect other barriers to entry; and (4) whether there is evidence involving the seller or its affiliates that relates to affiliate abuse or reciprocal dealing.[237] Today, FERC conducts its market-based rate assessment under Order 697, which codified FERC's market-based rate policy. Market-based rate applicants have to provide information about vertical market power and horizontal market power. Vertical market power, such as ownership of generation resources, is less of an issue as long as the applicant complies with FERC Order 888 (i.e., OATT requirements) and its affiliate abuse rules. As a result, the focus has shifted to FERC's analysis of horizontal market power.

FERC adopted two indicative screens for assessing horizontal market power: the pivotal supplier screen and the wholesale market share screen using a "snapshot in time" approach based on historical data.[238] The applicant must pass both the market share and pivotal supplier screens. FERC determined that "the consideration of market power is important in determining if customers have genuine alternatives to buying the seller's product."[239]

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[234] Order No. 697, 119 FERC ¶ 61,295 at P 849 n.1000 (2007); 18 CFR 35.36(a).
[235] *Id*. at 8.
[236] *Id*.
[237] Order No. 816, 153 FERC ¶ 61,065 at P 4 (2015).
[238] *Id*. at P 5.
[239] Order No. 697, 119 FERC ¶ 61,295 at P 791.

Generally, sellers that are located in and are members of the RTO/ISO may consider the geographic region under the control of the RTO/ISO as the default relevant geographic market for purposes of the indicative screens.[240] Sellers located outside RTO/ISO markets generally use the balancing authority area(s) where the seller is physically located and also where the markets directly interconnect to the seller's balancing authority area as the default relevant geographic market for purposes of the indicative screens.[241] Due to the large geographical area applicable to The Federation, the relevant geographic market to be used for analyses of the indicative screens will be yet another unique aspect of the project.

J. LOOKING FORWARD: FUTURE FERC ACTIONS NEEDED

1. Interregional Planning and Cost Allocation

Section IX.B highlights significant cost allocation and cost recovery challenges for the PftP Project. As an interregional transmission project, benefits and costs stemming from the PftP Project should be spread on an interregional basis; however, FERC Order 1000 has failed to deliver a functioning process to allocate costs across beneficiaries on an interregional basis. The planning process under FERC Order 1000 is the only option currently available to the PftP Project to establish a cost allocation methodology on an interregional basis. Unfortunately, this planning process has yet to approve a single interregional transmission project.

To spread costs across multiple regions, additional regulatory reform is needed. As raised in Section IX.B.1.c, FERC has indicated it will issue a NOPR to address interregional planning. This process will likely focus on improvements to FERC Order 1000.

2. Interregional Transmission Organization

To establish an interregional transmission organization (ITO) described in Sections VII.B and IX.H, FERC would likely commence a rulemaking proceeding that incorporate elements from FERC Order 2000. To be sure, this would be a multi-year effort. It is too early to speculate how FERC will address this issue.

[240] Order No. 816, 153 FERC ¶ 61,065 at P 5.

[241] *Id*. A balancing authority area means "the collection of generation, transmission, and loads within the metered boundaries of a balancing authority, and the balancing authority maintains load/resource balance within this area." Order No. 697, 119 FERC ¶ 61,295 at P 251.

3. The Federation – Interregional Power Marketer

The current process to obtain market-base rate authority under FERC Order 697 could be applied to the Federation as a wholesale power marketer on an interregional basis. Until more applicants come forward to sell wholesale power on an interregional basis, FERC will likely address interregional applicants on a case-by-case basis.

X. TASK 4: STUDY MANAGEMENT

This Task #4 involved keeping the CDS process on-time and on-budget. The CDS was completed on March 23, 2023 and within the project budget.

XI. ABOUT POWER FROM THE PRAIRIE LLC

Power from the Prairie LLC (PftP LLC) is incorporated in Iowa. With team members comprised of former utility executives and current utility resource planning, legal and regulatory subject matter experts, it was created to be an incubator for interregional HVDC electric transmission projects. Because development of such projects is simply not happening using current industry structures and processes. The goal of the LLC is to be “productively disruptive” of such legacy processes.

Importantly, by design PftP LLC is not a transmission or renewables project developer. Interregional projects by their scale and nature will involve multiple and diverse parties. And planning studies done by an individual equipment vendor or developer are typically viewed with suspicion by utility off-takers as potentially biased. Instead, PftP LLC is designed to represent a qualified, neutral, and independent due-diligence facilitator to get interregional planning studies and projects with multiple suppliers and off-takers to happen.

XII. ABOUT HITACHI ENERGY POWER CONSULTING

Hitachi Energy

The Power Consulting business within Hitachi Energy is the power system analysis and consulting center for Hitachi worldwide. Their US operations are located on the Centennial Campus of North Carolina State University in Raleigh, NC with branch offices in Albany, NY, and Orange County, CA.

Hitachi Energy has been providing consulting services to the electric industry worldwide for over 50 years. Their personnel have expertise in all areas of electric power transmission and distribution, including system analysis, planning and operations studies, software development, and equipment design and materials. Specifically, the team selected for this CDS has extensive experience in transmission planning, renewable integration, and the technical skills and experience to successfully complete it.

Power Consulting uses all the industry standard simulation software as needed to perform accurate evaluations. In addition, specialty proprietary programs have been developed in house, and utilized as needed, to evaluate unique problems or enhance the efficiency of study efforts.

The Power Consulting business is independent from any Hitachi Energy product groups, giving their engineers freedom to consider all possible technological solutions, including those not produced by Hitachi Energy. At the same time, they have direct access to leading world experts for support, when needed, on every technology produced by Hitachi Energy. The combination of independence and access to world class expertise provides the Power Consulting business with a unique capability to ensure that the best solutions are considered for every client's needs.

Power Consulting develops and maintains a production cost simulation tool – GridView, which has been widely used in ISOs, utilities, consulting firms, and developers in Americas and China. Power Consulting team has also provided consulting services on economic analysis in USA, Canada, China, Europe, and Middle East, etc. Recently consulting services included CAISO transmission economic assessment for Ten West Link, Economic Assessment transmission project in San Diego, Economic Assessment for SWIP North, Economic Assessment transmission projects in GridLiance West, WECC Anchor Data Set Development, and NYISO transmission planning database development, etc. They also use PROMOD for economic assessment for offshore wind (OSW) and transmission upgrades.

In addition, the staff includes world recognized experts in power system dynamics modeling and simulation and other system aspects, having helped to develop some of the algorithms included in PSS/E®. The staff also has broad global experience in renewable integration studies and headed the US DOE's National Offshore Wind Energy Grid Integration Study (NOWEGIS). Battery storage solutions have also been studied and supported around the world, including the Golden Valley BESS in Anchorage, Alaska.

With its broad experience and expertise, Hitachi Energy is well suited to support technical and economic studies in USA and around the world.

XIII. THE STUDY TEAM

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EXHIBITS:

Volume 2: Exhibits, Public Version

Volume 3: Exhibits, CDS Participant Version (Confidential)

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