BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

In the Matter of the Application of NextEra Energy Transmission Southwest, LLC for a Limited Certificate of Public Convenience and Necessity to Transact the Business of Public Utility in the State of Kansas	)	22-NETE-419-COC Docket No. 22-____-___-COC

DIRECT TESTIMONY OF BECKY WALDING,
EXECUTIVE DIRECTOR, DEVELOPMENT,
NEXTERA ENERGY TRANSMISSION, LLC

ON BEHALF OF

NEXTERA ENERGY TRANSMISSION SOUTHWEST, LLC

Docket No. 22-____-___-COC

FEBRUARY 28, 2022

Contents

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Becky Walding. My business address is 700 Universe Boulevard, Juno Beach, Florida 33408.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by NextEra Energy Transmission, LLC ("NEET") as Executive Director, Development. NEET is an indirect, wholly-owned subsidiary of NextEra Energy, Inc. ("NextEra Energy"). In my role as Executive Director, Development of NEET, my responsibilities include leading corporate efforts to develop, construct, operate, and acquire regulated and contracted power transmission and related assets in the United States and Canada. I am also the Assistant Vice President of the applicant in this proceeding, NextEra Energy Transmission Southwest, LLC (the "Applicant" or "NEET Southwest").

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of NEET Southwest.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I have over 24 years of experience working for two of the largest U.S. electric utility companies—NextEra Energy and Southern Company. My experience covers most major areas of utility planning and operations including transmission and system planning, regulatory, utility finance and accounting, asset management, and managing commercial operations in each U.S. electricity market. I hold a Bachelor of Science Degree in Chemical Engineering from Auburn University.

Q. HAS THIS DIRECT TESTIMONY BEEN PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes, it has.

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY BEFORE THE KANSAS CORPORATION COMMISSION OR ANY OTHER REGULATORY COMMISSION?

A. I submitted pre-filed written direct testimony before the Federal Energy Regulatory Commission ("FERC") on behalf of NEET Southwest's affiliate, Trans Bay Cable LLC, in FERC Docket No. ER19-2846-000. I also provided oral testimony before the Ontario Energy Board ("OEB") on behalf of another NEET Southwest affiliate, NextBridge Infrastructure LP ("NextBridge"), in support of its application for approval of electricity transmission revenue requirements, in OEB Docket No. EB-2021-0276.

Q. DO YOU SPONSOR ANY EXHIBITS IN SUPPORT OF NEET SOUTHWEST'S APPLICATION?

A. Yes. I sponsor Exhibits BW-1 through BW-7. Each of these exhibits was prepared or assembled by me or under my supervision and direction.

Q. WHAT AUTHORITY IS THE APPLICANT SEEKING TO OBTAIN IN THIS PROCEEDING?

A. The Applicant is seeking to obtain a Certificate of Convenience and Necessity ("CCN"), pursuant to K.S.A. 66-131, to transact business as a transmission-only public utility in Kansas and to construct, own, operate, and maintain a 345 kV transmission line project that will connect the existing Wolf Creek Substation in Coffey County, Kansas to the existing Blackberry Substation in Jasper County, Missouri (the "Project" or the "Wolf Creek-Blackberry Project"). The Kansas portion of the proposed Project will be approximately 85 miles, traversing through Coffey, Anderson, Allen, Bourbon, and Crawford counties. The Missouri portion of the Project will be approximately nine miles, for a total Project length of approximately 94 miles. The Project was identified by the Southwest Power Pool, Inc. ("SPP") as required to address multiple needs identified in the

2019 Integrated Transmission Planning ("ITP") process, including an economic need to increase the transmission capability from west to east within SPP.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my testimony is to support NEET Southwest's request for a CCN to transact business as a public utility in Kansas and to construct, own, operate, and maintain the Project. In particular, my testimony:

- Provides background on NEET Southwest and the corporate structure of its affiliates;
- Explains why NEET Southwest has the financial, managerial, and technical resources and qualifications to do business as a public utility in Kansas and to construct, own, operate, and maintain the Project;
- Provides background regarding NEET Southwest's participation in the SPP competitive solicitation for the Project; describes the purpose and need for the proposed Project; and demonstrates how the proposed Project will serve the public interest and the public convenience and necessity;
- Describes the proposed Project, including its proposed location and benefits;
- Provides the estimated cost of the proposed Project and explains how NEET Southwest is bound by cost containment measures;
- Establishes that NEET Southwest satisfies the Commission's factors for granting a CCN by:
    - Demonstrating that the Project will benefit customers and will have *de minimis* retail rate impacts on customers in Kansas;
    - Testifying that the Project will maximize the use of Kansas energy resources;
    - Demonstrating that the Project reduces the possibility of economic waste;
    - Demonstrating that granting NEET Southwest's requested CCN will not affect the Commission's jurisdiction and the capacity of the Commission to effectively regulate and audit public utility operations in the state; and

  - Describing the effect of the Project and granting the CCN on public utility shareholders;

- Explains why waiver or a finding of non-applicability of certain statutory requirements is in the public interest; and

- Requests that the Commission issue a final decision approving NEET Southwest's requested CCN.

My testimony also will introduce the testimony of NEET Southwest's other witnesses:

NEET Southwest Witness	**Testimony Topics**
Daniel Mayers, Director of Transmission and Substation Engineering, NextEra Energy Resources, LLC	• Describes NEET Southwest's technical and managerial qualifications to engineer and construct the Project • Provides an overview of the engineering details of the Project, including location, engineering design, estimated cost, construction schedule, and environmental impacts • Demonstrates that the Project will not adversely affect the environment
LaMargo V. Sweezer-Fischer, Executive Director, Operations, NextEra Energy Transmission, LLC	• Testifies to NEET Southwest's technical and managerial capabilities to operate and maintain the Project • Supports NEET Southwest's ability to operate the Project in a safe and reliable manner • Describes the technical and managerial capabilities of NEET Southwest's affiliates that will provide support for NEET Southwest's operation and maintenance of the Project
Amanda Finnis, Executive Director, Finance, NextEra Energy Transmission, LLC	• Testifies to the financial capabilities of NEET Southwest and the NextEra Energy organization • Explains how NEET Southwest intends to finance the Project
David G. Loomis, Ph.D., President, Strategic Economic Research, LLC	• Testifies that the Project will be beneficial on an overall basis to state and local economies and communities in the area of the Project

Q. HOW IS THE REST OF YOUR DIRECT TESTIMONY ORGANIZED?

A. Section II of my testimony describes NEET Southwest and its relevant parent companies and affiliates within the NextEra Energy organization. Section III addresses NEET Southwest's financial, managerial, and technical qualifications to operate as a public utility in the State of Kansas and to construct, own, operate, and maintain the Project. Section IV provides an overview of SPP's determination of the purpose and need for the proposed Project, as well as SPP's competitive bid process. Section V provides an overview of the Project, including its benefits and costs. Section VI describes the factors applied by the Commission in considering whether to grant a CCN and explains how granting NEET Southwest's requested CCN and the proposed Project satisfy those requirements. Section VII address NEET Southwest's request for waiver or finding of non-applicability of certain statutes.

Q. PLEASE SUMMARIZE WHY THE PUBLIC CONVENIENCE AND NECESSITY SUPPORTS ISSUANCE OF A CCN TO NEET SOUTHWEST TO OPERATE AS A PUBLIC UTILITY PROVIDING TRANSMISSION SERVICES IN KANSAS.

A. If the Commission authorizes NEET Southwest to transact business as a public utility in Kansas, NEET Southwest will develop, construct, own, operate, and maintain the Project, which will address needs identified by SPP and provide economic benefits to SPP customers. NEET Southwest is highly qualified to finance, construct, operate, and maintain the Project. Further, NEET Southwest's proposal for the Project was selected by SPP as the lowest cost, best option that provides significant benefits to the region. SPP found NEET Southwest's proposal to merit high scores in the vital areas of Engineering Design (including the highest-rated conductor of all proposals), Operations, and Finance, reflecting a balance across the scoring criteria that determine the value to SPP customers in addition to the lowest cost. SPP's selection process determined that NEET Southwest demonstrated it has the capabilities and processes to deliver the Project successfully with robust designs and competitive cost.

II. NEET SOUTHWEST BACKGROUND

Q. PLEASE DESCRIBE NEET SOUTHWEST.

A. NEET Southwest is a Delaware limited liability company formed in 2014 and qualified to do business in Kansas. NEET Southwest's certificate of formation in Delaware and qualification to do business in Kansas are provided in Exhibit BW-1. NEET Southwest was created to construct, own, and operate transmission assets in the SPP region. NEET Southwest was selected as the Designated Transmission Owner for the Project through SPP's competitive Transmission Owner Solicitation Process ("TOSP").

Q. PLEASE DESCRIBE NEET SOUTHWEST'S PARENT COMPANIES AND KEY AFFILIATES IN MORE DETAIL.

A. NEET Southwest is a direct, wholly-owned subsidiary of NEET, which in turn is an indirect, wholly-owned subsidiary of NextEra Energy. A Fortune 200 company, NextEra Energy is the world's largest electric utility by market capitalization, with revenues in calendar year 2021 of approximately $17 billion and approximately 15,000 employees as of December 31, 2021.

NextEra Energy's principal businesses are Florida Power & Light Company ("FPL"), Florida's largest electric utility serving approximately 5.7 million customer accounts, or more than 11 million people, and NextEra Energy Resources, LLC ("NEER"), the largest generator of renewable energy from the wind and sun in North America. NextEra Energy and its wholly-owned subsidiaries, NEET and NEET Southwest, are headquartered in Juno Beach, Florida.

NEET was formed by NextEra Energy in 2007 to apply NextEra Energy's experience and resources in developing, owning, and operating transmission facilities to projects across the U.S. and Canada. NEET serves as a holding company for NextEra Energy's regulated transmission utilities outside the state of Florida and is the immediate parent company of the applicant, NEET Southwest. NEET expanded its portfolio of operating transmission subsidiaries in 2021 with its acquisition of the entities owned by GridLiance Holdco LP, including GridLiance High Plains LLC ("GridLiance HP"), which jointly owns transmission assets in Winfield, Kansas with the City of Winfield and in Nixa, Missouri with the City of Nixa,[1] and which owns transmission assets in the Oklahoma Panhandle that serve Tri-County Electric Cooperative. The Commission approved NEET's acquisition of GridLiance HP in Docket No. 21-GLPE-160-ACQ in February 2021.[2]

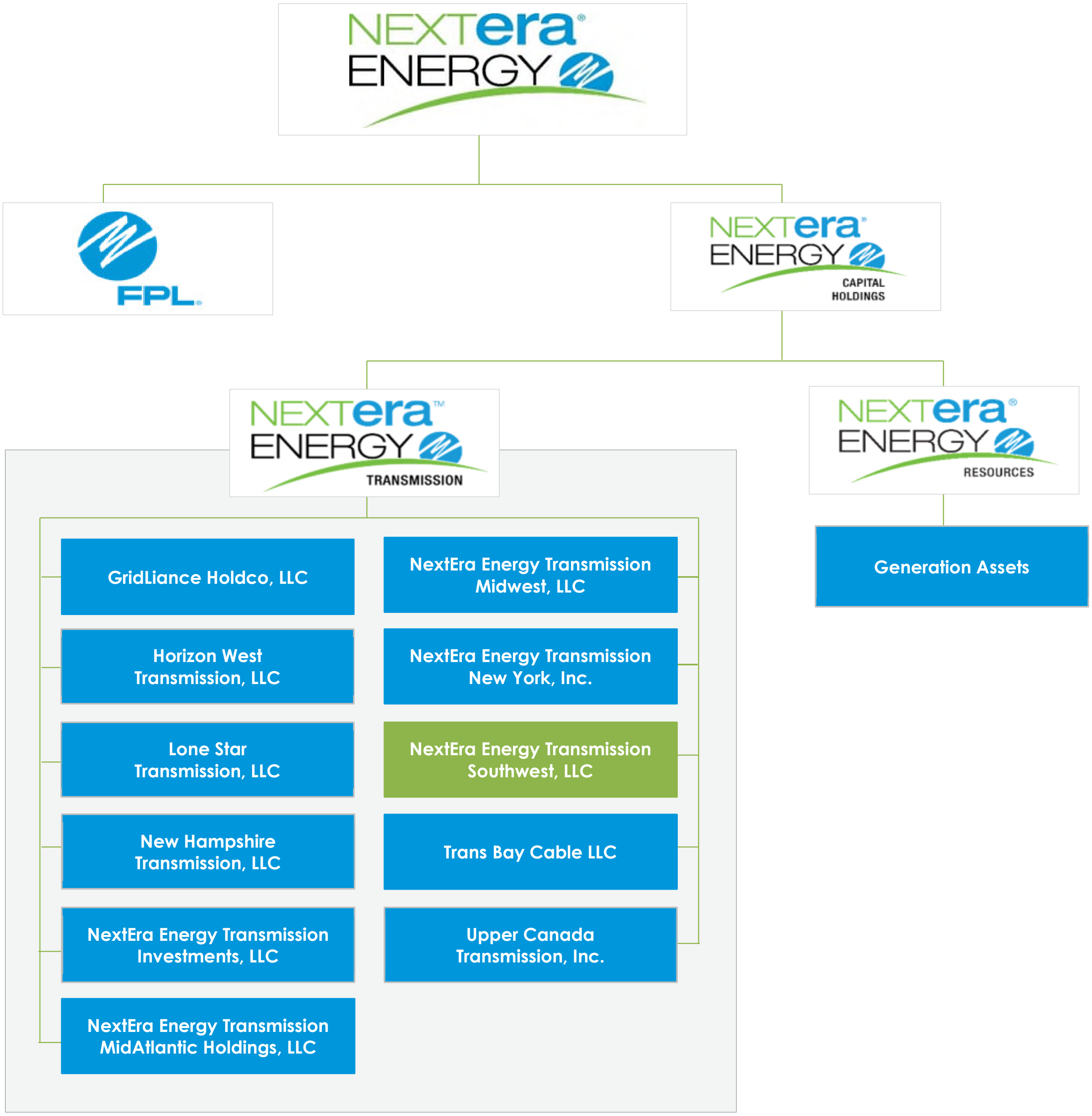
NEET subsidiaries' assets including operating transmission facilities in: Kansas (GridLiance HP); Missouri (GridLiance HP); Oklahoma (GridLiance HP); Texas (Lone Star Transmission, LLC ("Lone Star Transmission")); Illinois (GridLiance Heartland LLC); Indiana (NextEra Energy Transmission MidAtlantic Indiana, Inc.); New Hampshire (New Hampshire Transmission, LLC); New York (NextEra Energy Transmission New York, LLC ("NEETNY")); Nevada (GridLiance West LLC); and California (Horizon West

[1] The Missouri Public Service Commission ("MPSC") recently approved a proposal by GridLiance HP to transfer its ownership interests in the City of Nixa assets to the Missouri Joint Municipal Electric Utility Commission. Order Approving Application to Transfer Assets and Granting Waiver, File No. EM-2022-0156 (Feb. 9, 2022).

[2] *In the Matter of the Joint Application of GridLiance High Plains LLC, GridLiance GP, LLC, and GridLiance Holdco, LP ("GridLiance"), NextEra Energy Transmission Investments, LLC, and NextEra Energy Transmission, LLC ("NextEra Entities") for approval of the Acquisition of GridLiance by the NextEra Entities*, Docket No. 21-GLPE-160-ACQ (Feb. 2, 2021) ("GridLiance HP Acquisition Order").

Transmission, LLC ("Horizon West Transmission") and Trans Bay Cable LLC). NEET subsidiaries also have a project under construction in Ontario, Canada (the East-West Tie), as well as awarded projects in permitting in California and New York and numerous other projects in earlier stages of development throughout the U.S. The Texas and Ontario projects were won pursuant to the first competitive processes in those jurisdictions, and one of the California projects was the first to be awarded by the California Independent System Operator Corporation ("CAISO") to a non-incumbent transmission provider. Similarly, the proposed Project was the first to be awarded by SPP to a non-incumbent transmission provider.

The following simplified organizational chart illustrates the relationships between NEET Southwest and its parent company and certain key affiliates:


NEXTera ENERGY
FPL
NEXTera ENERGY CAPITAL HOLDINGS
NEXTera ENERGY TRANSMISSION
NEXTera ENERGY RESOURCES
GridLiance Holdco, LLC
Horizon West Transmission, LLC
Lone Star Transmission, LLC
New Hampshire Transmission, LLC
NextEra Energy Transmission Investments, LLC
NextEra Energy Transmission MidAtlantic Holdings, LLC
NextEra Energy Transmission Midwest, LLC
NextEra Energy Transmission New York, Inc.
NextEra Energy Transmission Southwest, LLC
Trans Bay Cable LLC
Upper Canada Transmission, Inc.
Generation Assets

III. NEET SOUTHWEST'S QUALIFICATIONS

Q. DOES NEET SOUTHWEST HAVE THE FINANCIAL, MANAGERIAL, AND TECHNICAL QUALIFICATIONS TO DO BUSINESS AS A PUBLIC UTILITY IN THE STATE OF KANSAS?

A. Yes. As discussed below and described in greater detail in the accompanying Direct Testimonies of Mr. Mayers, Ms. Sweezer-Fischer, and Ms. Finnis, NEET Southwest has the financial, managerial, and technical capabilities to transact business as a public utility providing transmission service in the State of Kansas. NextEra Energy, through its various affiliates, has extensive experience developing, permitting, constructing, owning, operating, and maintaining transmission systems around the U.S. and Canada. As part of the NextEra Energy family of companies, NEET Southwest will draw upon a deep reservoir of talented and committed NextEra Energy personnel from across the enterprise and will benefit from the experience of its parent companies and affiliates. NEET Southwest has assembled an experienced team comprised of internal and external resources and will apply these resources to its execution of the Project. NEET Southwest will utilize the same proven project management approach that other NextEra Energy affiliates have successfully employed for the safe, on-time, and under-budget execution of transmission and other energy infrastructure projects across North America.

Q. PLEASE PROVIDE MORE DETAILS ABOUT NEXTERA ENERGY'S FINANCIAL QUALIFICATIONS.

A. As an organization, NextEra Energy possesses exceptional financial stability and resources, and NEET Southwest will utilize these resources to ensure it has the financial capabilities to transact business as a public utility in Kansas. Ms. Finnis describes these financial capabilities in greater detail in her testimony. At a high level, NEET Southwest plans to finance the construction of the Project through financing provided by its indirect parent company, NextEra Energy Capital Holdings, Inc. ("NEECH"), which is a wholly-owned subsidiary of NextEra Energy. NEECH maintains a strong investment-grade credit profile, with current corporate ratings of Baa1/A-/A- from Moody's Investor Services, Standard & Poor's Global Ratings, and Fitch Ratings, respectively. As of December 31, 2021, NEECH had approximately $7.6 billion of net available liquidity, which enables it to fund major infrastructure projects. Therefore, NEET Southwest has the financial qualifications to construct, own, operate, and maintain the Project.

Q. PLEASE PROVIDE MORE DETAILS ABOUT NEXTERA ENERGY'S MANAGERIAL AND TECHNICAL EXPERTISE.

A. NextEra Energy also possesses significant managerial and technical expertise. NextEra Energy is an industry leader in producing clean and renewable electric energy and in delivering reliable and economical electric utility service to millions of customers. Necessarily, NextEra Energy is very experienced in constructing, owning, operating, and maintaining electric utility systems. Building on a 90-year history in the electric utility industry, NextEra Energy's subsidiaries own and operate more than 55.3 gigawatts of electricity generating capacity primarily across 38 states in the U.S. and four provinces in Canada, and approximately 11,800 circuit miles of high-voltage transmission, approximately 77,400 miles of distribution lines, and over 1,000 substations across North America. FPL, one of NextEra Energy's principal subsidiaries, is the nation's largest electric utility as measured by retail electricity produced and sold and serves more than 5.7 million homes and businesses in Florida, or more than 11 million people.

NEET Southwest's direct parent company, NEET, also has extensive managerial and technical experience in owning and operating regulated transmission utilities across the U.S. NEET is an experienced utility holding company, and as I described above, NEET subsidiaries own and operate, and/or are constructing, regulated transmission facilities in nine U.S. states and one Canadian province. NEET's expertise in owning and managing its regulated utility subsidiaries provides it with substantial expertise that NEET Southwest will utilize to operate as a public utility in Kansas.

NextEra Energy's managerial and technical expertise is illustrated in industry awards that its companies routinely receive. For example, FPL has been named one of the most reliable utilities in the industry year over year and maintains top-decile reliability metrics. As Ms. Sweezer-Fisher includes in her testimony,[3] in 2021, PA Consulting recognized FPL with the Outstanding Reliability Performance Award for the Southeast metropolitan region for the eighth straight year, the Outstanding Technology & Innovation Award for the fifth time in eight years, and the Outstanding System Resiliency Award for the first time ever, as well as with the National Reliability Excellence Award for the sixth time in the last seven years.

Q. HAS NEXTERA ENERGY BEEN RECOGNIZED WITH ANY OTHER INDUSTRY AWARDS?

A. Overall, NextEra Energy is widely regarded as one of the leading companies in the U.S. utility industry. As an example, NextEra Energy was named number one in its sector for the 15th time in the last 16 years on Fortune magazine's "Most Admired Companies" list through 2022. Also, NextEra Energy ranked number one on Ethisphere's World's Most Ethical Companies 2021 report, becoming one of only 13 companies in the world to achieve this honor 14 or more times. Other awards NextEra Energy has earned include: Forbes' 2021 America's Best Large Employers for the fifth time; the first utility company

[3] *See* Sweezer-Fisher Direct Testimony at 7-8.

to be named on the inaugural 2021 Time's 100 Most Influential Companies; S&P Global Platts Leadership Recognition for Environmental, Social and Governance; and the U.S. Department of Labor's Excellence Award for excellence in recruiting, employing, and retaining veterans.

Q. PLEASE DESCRIBE NEXTERA ENERGY'S SAFETY RECORD.

A. NextEra Energy also maintains one of the strongest safety records in the industry, an indicator both of operational excellence and of the high value we place on the well-being of our employees and contractors, as Mr. Mayers and Ms. Sweezer-Fischer address in their testimonies.[4] NextEra Energy consistently ranks within the industry top-decile on safety metrics. NEET Southwest affiliate, Lone Star Transmission, which will provide 24/7 operation oversight for the Project, has never had an Occupational Safety and Health Administration recordable incident. NextEra Energy is also at the forefront of developing safety programs to navigate the coronavirus (COVID-19) crisis to maintain the health and safety of its employees and uninterrupted service to customers.

Q. HOW DOES NEET SOUTHWEST BENEFIT FROM THE EXPERIENCE OF ITS PARENT COMPANIES AND AFFILIATES?

A. NEET Southwest will draw upon the resources within the NextEra Energy organization to ensure its successful execution of the Project. NextEra Energy companies typically operate under a support services model, which enables the organization to apply best practices, a highly skilled workforce, and economies of scale across the enterprise. NEET Southwest will have access to the following affiliate resources for this Project:

[4] *See* Mayers Direct Testimony at 9-10; Sweezer-Fisher Direct Testimony at 7-8.

- Engineering and Construction Organization – consisting of over 100 engineers and construction project managers with substantial experience in large-scale energy infrastructure projects;
- Integrated Supply Chain – consisting of over 400 sourcing and procurement specialists that leverage NextEra Energy's significant purchasing power and relationships with strategic industry vendors; this team procured $16 billion in materials and services in 2021 alone;
- Environmental Services – consisting of over 100 environmental subject matter experts, specialized in minimizing project impact to the environment, as well as reducing permitting and schedule risk to projects;
- Power Delivery – consisting of over 3,200 highly experienced operations and maintenance team members with an industry-leading track record in safety and reliability; and
- Regulatory and Legal – consisting of over 100 attorneys and regulatory specialists, with particular expertise in federal, state, and local regulatory proceedings for the energy sector.

NEET Southwest's ability to rely on the substantial and highly-qualified expertise within the NextEra Energy corporate family in all operational and administrative dimensions of developing, constructing, owning, operating, and maintaining the Project is a primary driver of its ability to deliver the Project on schedule and effectively manage costs, and will ensure that expertise is available to NEET Southwest for efficient and reliable future operations.

The significant economies of scale attendant to using available affiliate resources will benefit Kansas customers. As part of this Application, NEET Southwest is requesting Commission waiver of K.S.A. 66-1402 and 66-1403 to allow for the use of these affiliate resources. Waiver is appropriate because the costs of NEET Southwest's use of these affiliate resources are subject to oversight by FERC. Specifically, as a public utility providing transmission service over FERC-jurisdictional transmission facilities, NEET Southwest is subject to FERC's cross-subsidization restrictions on affiliate transactions, found at 18 C.F.R. §§ 35.43-.44. These restrictions preclude NEET Southwest from receiving non-power goods or services from a market-regulated or non-utility affiliate at prices above market value.

Q. HAS THE COMMISSION PREVIOUSLY OPINED ON THE QUALIFICATIONS OF THE NEXTERA ENERGY ORGANIZATION TO OWN AND OPERATE TRANSMISSION FACILITIES IN THE STATE OF KANSAS?

A. Yes. In the Commission's GridLiance HP Acquisition Order, issued in February 2021, the Commission addressed whether "NextEra, as the new owner of GridLiance HP, possesses the necessary managerial, technical, and other experience necessary to operate and own a transmission line."[5] The Commission found that it did—making a number of findings related to NextEra Energy's overall qualifications to own and operate transmission facilities in the state, including the following:

- "NextEra has a track record of operating public utility businesses in the United States and Canada, including transmission assets and services."[6]
- "NextEra possesses significant financial qualifications, including investment grade bond ratings, and approximately $7.5 billion in net liquidity. GridLiance HP will depend on NextEra and its entities for equity capital beyond that which is available through GridLiance's retained earnings, and there exists the possibility NextEra will be a source of debt capital for GridLiance…. These facts demonstrate NextEra possesses the financial capability, while also retaining managerial and technical experience to own and operate the transmission assets. As such, the threshold question is met."[7]
- "[T]he record indicates the Proposed Transaction will result in GridLiance HP being owned by a financially strong company with a proven track record of investing in energy infrastructure."[8]

[5] GridLiance HP Acquisition Order at ¶ 16.

[6] *Id.* at ¶ 17.

[7] *Id.*

[8] *Id.* at ¶ 20.

NEET Southwest, as another NextEra Energy subsidiary, benefits from this same overall financial, managerial, and technical strength of the NextEra Energy organization.

Q. HAVE OTHER REGULATORY AGENCIES RECOGNIZED THE EXPERTISE OF NEXTERA ENERGY SUBSIDIARIES TO PROVIDE TRANSMISSION SERVICE?

A. Yes, the financial, managerial, and technical qualifications of the NextEra Energy organization have been recognized by other regulatory commissions, as well. For example, in 2021, in granting a certificate of public convenience and necessity to NEET subsidiary NEETNY for a 20-mile, 345 kV transmission line in Erie County, New York (the Empire State Line or "ESL Project"), the New York Public Service Commission ("New York PSC") determined:

> [T]he record demonstrates that NEETNY is feasible from an economic perspective and capable of financing the construction and maintenance of the ESL Project, as well as undertaking improvements. NEETNY will rely upon upstream corporate affiliates for financial backing, [NextEra Energy and NEECH]. The record reflects that NextEra Energy has significant assets and equity available to fund the ESL Project and that it maintains strong investment-grade credit ratings.
>
> NEETNY has also demonstrated that, with its affiliates, it has the technical expertise to render safe, adequate, and reliable service, NEETNY will rely upon NextEra Energy's resources and personnel that have significant experience in developing, permitting, constructing, owning and operating transmission systems.[9]

Similarly, in 2018, the California Public Utilities Commission ("CPUC") granted NEET subsidiary Horizon West Transmission a CPCN to construct, own, operate, and maintain a 230 kV dynamic reactive power support station (the "Suncrest SVC Project") and associated one-mile 230 kV transmission line that was awarded through a CAISO

[9] *Petition of NextEra Energy Transmission New York, Inc. for an Order Granting Certificate of Public Convenience and Necessity Pursuant to Section 68 of the Public Service Law*, Case 18-E-0765 at 19-20 (Feb. 11, 2021).

competitive transmission solicitation. In doing so, the CPUC noted that Horizon West Transmission "proposes to use resources and facilities within the NextEra corporate organization to facilitate construction and operation of the Proposed Project."[10]

Finally, in selecting NEET subsidiary Lone Star Transmission as a new entrant transmission provider to construct approximately 330 miles of new 345 kV transmission lines as part of the Electric Reliability Council of Texas Competitive Renewable Energy Zone ("CREZ") transmission buildout, the Public Utility Commission of Texas ("PUCT") determined that "the current and projected financial resources demonstrated by each of these entities [including Lone Star Transmission] establishes that each is capable of financing, licensing, constructing, operation, and maintaining the [CREZ transmission] facilities assigned to them in a beneficial and cost-effective manner" and that Lone Star Transmission was one of three new entrant entities "best qualified to participate in the [CREZ transmission project]."[11]

Q. WILL NEET SOUTHWEST UTILIZE THIRD-PARTY RESOURCES TO DEVELOP, DESIGN, CONSTRUCT, AND OPERATE THE PROJECT?

A. Yes. In addition to using its extensive support from the NextEra Energy organization, NEET Southwest also will engage and rely on experienced, qualified companies to assist in these functions. NEET Southwest has contracted or expects to contract with the following firms experienced in land acquisition, transmission line routing, environmental services, and engineering, procurement, and construction activities:

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[10] *In the Matter of the Application of NextEra Energy Transmission West, LLC*, Application No. (A.) 15-08-027, Decision (D.) 18-09-030 at 6 (Oct. 2, 2018).

[11] *Commission Staff's Petition for Selection of Entities Responsible for Transmission Improvements Necessary to Deliver Renewable Energy from Competitive Renewable-Energy Zones*, PUCT Docket No. 35665, Order on Rehearing at 12 (May 15, 2009).

- Doyle Land Services, which will assist NEET Southwest with right of way ("ROW") acquisition efforts for the Project, utilizing local land agents;
- Burns & McDonnell Engineering Company, Inc. ("B&M"), which will assist with the engineering, environmental, and routing aspects of the Project and has been selected as the Engineer of Record for the Project. B&M prepared a preliminary routing analysis, through which NEET Southwest identified a preliminary proposed route for the Project, which NEET Southwest presented to SPP in its bid;
- Brink Constructors, Inc., which will serve as NEET Southwest's construction contractor for the Project; and
- Polsinelli, PC, a leading law firm in the energy practice with decades of experience assisting utilities and energy companies in Kansas and in the Midwest that will assist NEET Southwest in understanding and meeting legal and regulatory requirements as they arise.

NEET Southwest will oversee, supervise, and control the activities of its outside contractors through its own experienced management team.

IV. SPP'S DETERMINATION OF THE PURPOSE AND NEED FOR THE WOLF CREEK-BLACKBERRY PROJECT AND THE COMPETITIVE BID PROCESS

Q. PLEASE DESCRIBE THE PROJECT.

A. At a high level, the Project consists of a new single-circuit 345 kV transmission line between the existing Wolf Creek Substation, owned by Evergy Kansas Central, Inc. ("Evergy") in Coffey County, Kansas to the existing Blackberry Substation, owned by Associated Electric Cooperative, Inc. ("AECI") in Jasper County, Missouri. The proposed route for the Project is approximately 94 miles, with approximately 85 miles in Kansas and approximately nine miles in Missouri. The Project will span five counties in Kansas (Coffey, Anderson, Allen, Bourbon, and Crawford counties) and two counties in Missouri (Barton and Jasper counties). A map providing the general location of the Project is included as Exhibit BW-2 to my testimony.

Q. PLEASE DESCRIBE THE GENESIS OF THE PROJECT.

A. The Project was identified by SPP in its 2019 ITP Assessment, provided as Exhibit BW-3 to my testimony, as a project that was required to address multiple needs, and in particular, an economic need to increase the transmission capability and relieve transmission congestion from west to east within SPP. SPP designated the Project as a Competitive Upgrade that was eligible for competitive bidding pursuant to the SPP TOSP under Attachment Y of the SPP Open Access Transmission Tariff ("SPP Tariff"),[12] which competitive process was implemented in response to FERC Order No. 1000.[13]

Q. PLEASE DESCRIBE SPP'S IDENTIFIED NEEDS FOR THE PROJECT IN MORE DETAIL.

A. SPP evaluated the need for the Project as part of its 2019 ITP process and identified the need for the Project as addressing "multiple 2019 ITP needs",[14] including economic and additional needs. SPP explained that it had evaluated the transmission needs in southeast Kansas and southwest Missouri "for several reasons."[15] Specifically, SPP identified the following congestion issues experienced in this area:

> The area has been the site of historic and projected congestion on the [extra-high voltage ("EHV")] system and has had unresolved transmission limits identified in multiple studies, most recently in the 2018 [ITPNT]…. Continued integration of wind generation on the western side of the SPP system has contributed to diminishing transmission capacity capable of supporting bulk power transfers to the east. This has led to declining transient stability margins at the Wolf Creek nuclear plant. The Butler-Altoona 138 kV line in southeast Kansas, already known for its advanced age, was identified by NERC as having one of the highest outage rates for

[12] SPP Open Access Transmission Tariff, Sixth Revised Vol. No. 1, Attachment Y (Transmission Owner Designation Process) (effective Mar. 30, 2014).

[13] *See Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 76 Fed. Red. 49,842 (Aug. 11, 2011), FERC Stats. & Regs. ¶ 31,323 at P 545 and Appendix C (2011).

[14] Exhibit BW-3 (2019 ITP Assessment) at § 7.1.1.

[15] *Id.* at § 4.1.1.1.

> its voltage class. It regularly experiences high system flows during times of elevated wind output. The Neosho-Riverton 161 kV line to the south is also a common issue in real-time operations. The Wolf Creek 345/69 kV transformer, which supplies the 69 kV network of loads between Wolf Creek and Neosho, frequently experiences heavy congestion and loading when the Waverly-La Cygne line is outaged in both reliability and economic analyses.[16]

Q. WHY DID SPP RECOMMEND THE PROJECT TO ADDRESS THESE NEEDS?

A. In recommending the Project in its 2019 ITP Assessment, SPP explained:

> The major study driver for the new Wolf Creek-Blackberry 345 kV line is its ability to relieve congestion and divert bulk power transfers away from the Wolf Creek-Waverly-La Cygne 345 kV line, Wolf Creek 345/69 kV transformer and downstream 69 kV lines, and allowing system bulk power transfers to continue to flow east to major SPP load centers. This will help to levelize system [locational marginal prices ("LMP")], low generator LMPs in the west and high load LMPs in the east, and overall system congestion while providing market efficiencies and benefits to ratepayers and transmission customers.
>
> The new 345 kV line parallels three major contingencies in the area: Caney River-Neosho 345 kV line, Wolf Creek-Waverly-La Cygne 345 kV line, and Neosho-Blackberry 345 kV. Paralleling the Neosho-Blackberry 345 kV line relieves congestion on the Neosho-Riverton 161 kV for the Neosho-Blackberry 345 kV line outage and reduces congestion on Neosho-Riverton 161 kV line for the loss of Blackberry-Jasper 345 kV line outage.[17]

Q. DID SPP IDENTIFY ANY OTHER NEEDS FOR OR BENEFITS OF THE PROJECT?

A. Yes. In addition to meeting economic needs, SPP also indicated that "the new Wolf Creek-Blackberry 345 kV line…resolves multiple 2019 ITP needs and additional issues identified for Target Area 1."[18] In particular, SPP explained that the Project:

> [R]esolves declining transient stability margins at the Wolf Creek nuclear plant by adding a fourth 345 kV outlet that is expected to increase system resiliency and reduce system operation risks. Dynamic simulations show the performance of the Wolf Creek unit with the addition of the Wolf Creek-

[16] *Id.* at § 4.1.1.1.

[17] *Id.* at § 7.1.1.

[18] *Id.*

> Blackberry 345 kV transmission line met the 'SPP Disturbance Performance Requirements.' This solution will address the transient stability limit discussed previously in Section 4.1.1.1.
>
> The Wolf Creek-Blackberry 345 kV line adds transmission capacity that is expected to relieve system loading and increase available transfer capability (ATC) to local long-term transmission service customers. This should also improve positions of candidate [Auction Revenue Rights ("ARR")] holders that would lead to improved [Transmission Congestion Rights ("TCR")] funding and reduce the need for counterflow optimization. This line would specifically help to mitigate the Neosho-Riverton 161 kV ARR constraints.[19]

SPP also determined that the Project "provides additional flexibility for future expansion options, including further expansion into eastern load centers and the opportunity for future seams projects with neighboring regions."[20]

Q. YOU MENTIONED THAT SPP DESIGNATED THE PROJECT AS A COMPETITIVE UPGRADE UNDER ATTACHMENT Y OF ITS TARIFF. HOW DID SPP SOLICIT COMPETITIVE BIDS FOR THE PROJECT?

A. SPP issued its Request for Proposals ("RFP") for bidders on the Project on September 28, 2020 (as subsequently updated on December 7, 2020) and required bids to be submitted by March 29, 2021. A copy of the RFP is provided as Exhibit BW-4 to my testimony. A total of seven bids were submitted to SPP by four bidding entities.

Q. PLEASE DESCRIBE SPP'S RFP IN MORE DETAIL.

A. SPP's RFP solicited proposals from Qualified RFP Participants for the Project and provided the following specifications, among others:

- Need Date for Project: January 1, 2026
- Study Cost Estimate for entire Project (+/-30%): $155,524,855
- Study Cost Estimate for Competitive Upgrade: $142,601,178

[19] *Id.*

[20] *Id.*

- Project Overview: The Competitive Upgrade portion of this RFP requires construction of a new 345 kV transmission line from the Wolf Creek substation to the Blackberry substation to address economic needs.[21]

The RFP also explained that the Project included certain non-competitive portions that would be assigned to the existing transmission facility owners, AECI and Evergy:

- "The Blackberry substation is owned by Associated Electric Cooperative, Inc. (AECI). SPP will coordinate with AECI to install any 345 kV terminal equipment at the existing Blackberry substation necessary to accommodate termination of [the] new 345 kV line." [22]

- "The Wolf Creek substation is owned by Evergy Kansas Central, Inc. (EKC). SPP will issue a [Notification to Construct ("NTC")] to EKC to install any 345 kV terminal equipment at the existing Wolf Creek substation necessary to accommodate termination of [the] new 345 kV line."[23]

Q. HOW DID NEET SOUTHWEST RESPOND TO SPP'S RFP?

A. NEET Southwest submitted one bid in response to SPP's RFP on March 26, 2021. In its proposal, NEET Southwest proposed to construct an approximately 94-mile, 345 kV transmission line between the Wolf Creek and Blackberry Substations. NEET Southwest's proposed cost for the Project was $85.2 million in 2021 dollars [redacted]. The series of cost containment measures proposed by NEET Southwest ensures the ultimate project costs are consistent with its estimates and provides benefits to customers, which I will describe in further detail below. NEET Southwest

[21] Exhibit BW-4 (SPP RFP) at 6.

[22] *Id.*

[23] *Id.*

proposed to place the Project in service twelve months ahead of SPP's projected in-service date, or by January 1, 2025, which will result in approximately $14.5 million in present value production cost savings to SPP customers.

Q. WHAT WAS SPP'S PROCESS FOR REVIEWING THE BIDS THAT WERE SUBMITTED IN RESPONSE TO THE RFP?

A. SPP's competitive process is designed to select the right long-term project for the benefit of SPP's customers. Under Attachment Y of the SPP Tariff, an Industry Expert Panel ("IEP") compares RFP responses and allocates points according to Engineering Design, Project Management, Operations, Rate Analysis (cost), and Financial Capabilities. The IEP issued its report for the Project on October 12, 2021 ("IEP Report"), provided as Exhibit BW-5 to my testimony, which recommended the selection of NEET Southwest's proposed project as the selected bid.

Q. PLEASE DESCRIBE THE IEP REPORT IN MORE DETAIL.

A. In the IEP Report, the IEP described its review process and scoring methodology for the Project. According to the report, the IEP adopted a scoring philosophy to allocate points to specific criterion/sub-criterion in each scoring category, based upon the percentage of available points awarded to a particular bid in a certain category.[24] Following the IEP's evaluation, it "unanimously recommend[ed] Proposal C [NEET Southwest's proposal] as the Recommended RFP Proposal."[25] In doing so, the IEP explained:

> Proposal C received the highest overall point allocation for its proposal to construct, operate and maintain the [Project]. Proposal C also received the highest point allocation in the scoring of Rate Analysis, which represents the lowest cost proposal to SPP customers. The strength of Proposal C went beyond being the lowest cost. The IEP recommendation found Proposal C to merit high scores in the vital areas of Engineering Design (including the

[24] Exhibit BW-5 (IEP Report) at 5.

[25] *Id.* at 8, 46.

> highest rated conductor of all proposals), Operations and Finance. The high point scores in these areas reflect a balance across scoring criteria that determine the value to SPP customers, not just the cost. The IEP believes Proposal C demonstrated that it offers capabilities and processes that can deliver a successful project, that the proposed designs are robust and that the resulting costs are competitive.[26]

The IEP Report also found that NEET Southwest's proposal had demonstrated a number of particular strengths, including:

- A "very substantial savings to SPP customers with a net present value of the revenue requirements tens of millions of dollars lower than other proposals";
- "[D]esign and materials solutions not offered by other Respondents, including the use of the highest thermal-rated conductor of any of the proposals";
- A "strong procurement process and team that manages vendor relationships and leverages economies of scale to secure most favorable terms";
- A proposed construction schedule that "included significant time float, enabling the Respondent to offer a guaranteed schedule for the Project";
- "[W]ell-defined construction cost estimates from a detailed and structured review process used over many years and many projects";
- "The proposal provides cost caps", including binding caps on the Project's construction costs and revenue requirement, as will be described in more detail below;
- "[R]elevant agreements showing the preparedness of the Respondent to take on the required operations and maintenance responsibilities";
- "[S]pecific preventative and predictive maintenance plans specific to this project based on principles and examples of statistical process controls to determine appropriate frequency and the extent of future maintenance activities"; and
- Demonstrated "established switching coordination, planned outage and operating coordination experience and protocols with SPP-member utilities."[27]

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[26] *Id.*

[27] *Id.* at 46.

Q. DID THE SPP BOARD APPROVE THE IEP'S RECOMMENDATION?

A. Yes. At its October 26, 2021 Board meeting, the SPP Board voted to approve the IEP's recommendation of NEET Southwest as the Designated Transmission Owner for the Project. A copy of the SPP Board's press release is provided as Exhibit BW-6 to my testimony.

Q. HAS SPP ISSUED ITS NOTIFICATION TO CONSTRUCT THE PROJECT TO NEET SOUTHWEST?

A. Yes. SPP issued its Notification to Construct ("NTC") the Project to NEET Southwest on December 6, 2021. NEET Southwest accepted the NTC in writing on December 8, 2021, and SPP issued a letter accepting NEET Southwest's commitment to construct the Project on December 20, 2021. The SPP NTC and NEET Southwest's acceptance letter are provided as Exhibit BW-7 to my testimony.

V. OVERVIEW OF THE WOLF CREEK-BLACKBERRY PROJECT

Q. PLEASE DESCRIBE THE PROPOSED PROJECT.

A. As I have testified above, NEET Southwest's proposed Project will consist of a new, approximately 94-mile, single-circuit 345 kV transmission line between the Wolf Creek Substation and Blackberry Substation. The Project will be located across five counties in Kansas (Coffey, Anderson, Allen, Bourbon, and Crawford counties) and two counties in Missouri (Barton and Jasper counties). NEET Southwest proposed a preliminary route to SPP as part of its bid, which is shown on the map in Exhibit BW-2. NEET Southwest is currently undertaking its public outreach process to develop its more detailed route and route alternatives, and NEET Southwest will file a separate application with the Commission under the Kansas Electric Transmission Line Siting Act, K.S.A. 66-1,177 *et seq.*, requesting approval of the Project's location prior to constructing the Project. NEET

Southwest witness Mr. Mayers describes the engineering aspects of the Project, the Project location, and the additional regulatory approvals and permits that NEET Southwest expects to seek for the Project in his Direct Testimony.

Q. WHAT IS NEET SOUTHWEST'S CURRENT PROJECTED IN-SERVICE DATE FOR THE PROJECT?

A. NEET Southwest has committed to SPP to an in-service date for the Project of January 1, 2025, which is 365 calendar days prior to the in-service date of January 1, 2026 required by SPP's RFP. This earlier in-service date will provide significant economic benefits to SPP customers, as I describe below. Mr. Mayers describes the Project's schedule in his Direct Testimony in more detail.[28]

Q. WHAT IS NEET SOUTHWEST'S PROPOSED COST FOR THE PROJECT?

A. NEET Southwest's proposed cost for the Project is $85.2 million in 2021 dollars [redacted], and subject to cost containment measures that NEET Southwest proposed in its bid to SPP.

Q. PLEASE DESCRIBE THESE COST CONTAINMENT MEASURES IN MORE DETAIL.

A. NEET Southwest's bid to SPP proposed a robust package of cost containment measures in [redacted]

[28] *See* Mayers Direct Testimony at 21-22.

[redacted] NEET Southwest's early in-service date also provides $14.5 million in estimated present value production cost savings to SPP customers.

Q. HOW WILL THE COSTS OF THE PROJECT BE RECOVERED?

A. As Ms. Finnis testifies, the costs of the Project will be recovered solely through NEET Southwest's transmission rates under the SPP Tariff, following acceptance by FERC, pursuant to FERC's exclusive jurisdiction over rates for wholesale interstate transmission service.[29]

VI. NEET SOUTHWEST SATISFIES KANSAS LEGAL REQUIREMENTS FOR ISSUING A CCN

Q. ARE YOU FAMILIAR WITH THE STATE OF KANSAS' REQUIREMENTS FOR ISSUING A CCN?

A. Yes. Although I am not an attorney, I understand that Kansas law requires applicants seeking a CCN to demonstrate that they have the necessary financial, technical, and managerial resources to conduct the business of a public utility. In reviewing CCN applications, I understand that the Commission also examines the Merger Standards

[29] *See* Finnis Testimony at 7-9.

originally adopted in Docket Nos. 172,745-U and 174,155-U.[30] I understand that the Commission has articulated the Merger Standards as encompassing the evaluation of the factors listed below. Some of these factors may not be applicable to NEET Southwest's application, as the transmission facilities transmit energy and capacity at wholesale and will be rate-regulated by FERC. Nevertheless, to the extent they are applicable, the Merger Standards are as follows:

- The effect of the transaction on customers;
- Whether the transaction maximizes the use of Kansas energy resources;
- Whether the transaction will reduce the possibility of economic waste;
- Whether the transaction will be beneficial to state and local economies and to communities served by the resulting public utility operations in the state;
- The effect of the transaction on affected public utility shareholders;
- The effect of the transaction on the environment;
- What impact, if any, the transaction has on public safety; and
- Whether the transaction will preserve the jurisdiction of the KCC and the capacity of the KCC to effectively regulate and audit public utility operations in the state.

In previous CCN cases, I understand that the Commission also has addressed the impact on transmission in other states and the historical presence of the applicant and its affiliates in Kansas.

Q. DOES NEET SOUTHWEST SATISFY THESE REQUIREMENTS?

A. Yes. As I and NEET Southwest's other witnesses testify, NEET Southwest satisfies the applicable Commission requirements for issuing NEET Southwest's requested CCN.

[30] Consolidated Docket Nos. 172,745-U and 174,155-U, Order at pp. 34-35 (Nov. 4, 1991); *see also*, Docket No.08-ITCE-936-COC *et al.*, Order at ¶ 52 (Dec. 18, 2008).

Q. WHICH OF THE COMMISSION'S REQUIREMENTS DO YOU ADDRESS IN YOUR DIRECT TESTIMONY?

A. I testify that NEET Southwest satisfies the following Merger Standards:

- The effect of the transaction on customers (*see infra* at 32);
- Whether the transaction maximizes the use of Kansas energy resources (*see infra* at 36-37);
- Whether the transaction reduces the possibility of economic waste (*see infra* at 37-38);
- The effect of the transaction on public utility shareholders (*see infra* at 38-39);
- Whether the transaction will preserve the jurisdiction of the Commission and the capacity of the Commission to effectively regulate and audit public utility operations in the state (*see infra* at 39);
- Whether NEET Southwest has the financial, technical, and managerial capabilities to construct, own, operate, and maintain the Project (*see infra* at 40);
- The impact on transmission in other states (*see infra* at 40-41); and
- The historical presence of NEET Southwest and its affiliates in Kansas (*see infra* at 41-42 *and* Direct Testimony of Mr. Mayers at 25).

NEET Southwest's other witnesses will testify as to the Commission's other applicable requirements for granting a CCN:

- Whether the transaction will be beneficial to state and local economies and to communities served by the resulting public utility operations in the state (*see* Direct Testimony of Dr. Loomis at 6-7);
- The effect of the transaction on the environment (*see* Direct Testimony of Mr. Mayers at 26);
- What impact, if any, the transaction has on public safety (*see* Direct Testimony of Mr. Mayers at 26-27 and Direct Testimony of Ms. Sweezer-Fischer at 12-13);
- Whether NEET Southwest has the financial ability to finance the Project (*see* Direct Testimony of Ms. Finnis at 9); and
- Whether NEET Southwest has the technical operations ability to build and operate the Project (*see* Direct Testimony of Mr. Mayers at 27 and Direct Testimony of Ms. Sweezer-Fischer at 13-14).

A. GRANTING NEET SOUTHWEST'S REQUESTED CCN TO CONSTRUCT, OWN, OPERATE, AND MAINTAIN THE PROJECT WILL BENEFIT CUSTOMERS IN KANSAS

Q. PLEASE DESCRIBE HOW THE PROJECT WILL AFFECT CUSTOMERS IN KANSAS.

A. Granting NEET Southwest a CCN to construct, own, operate, and maintain the Project will have a positive effect on customers in Kansas. In particular, the Project will provide economic benefits to the SPP grid, and NEET Southwest's selection as the Designated Transmission Owner for the Project results in significant and binding cost savings for SPP customers. Moreover, the Project will have *de minimis* retail rate impacts on Kansas customers, as I describe in more detail below.

Q. IS THE PROPOSED COST FOR THE PROJECT REASONABLE?

A. Yes, it is. NEET Southwest's proposed Project cost is reasonable for a number of reasons. First, NEET Southwest's proposed cost for the Project was closely evaluated by SPP's IEP and selected as the lowest, best cost for the Project through the SPP competitive bidding process. In fact, NEET Southwest's proposed Project cost is approximately $57.4 million less than SPP's estimated costs of $142.6 million for the competitive portion of the Project[31] and was approximately 30 percent less than the average bid.[32] NEET Southwest also proposed a significant set of cost containment measures to ensure customers are protected with the construction of the Project. In addition, because costs for the Project will be recovered through NEET Southwest's FERC-accepted formula rate and associated customer review and challenge protocols, the prudence of NEET Southwest's project expenditures and the applicability of NEET Southwest's cost containment commitments to

[31] *See* Exhibit BW-4 (SPP RFP).

[32] *See* Exhibit BW-5 (IEP Report) at 8.

such expenditures will be subject to FERC oversight, consistent with FERC's exclusive jurisdiction over transmission in interstate commerce under the Federal Power Act. For all of these reasons, the proposed cost for the Project is reasonable.

Q. DOES NEET HAVE EXPERIENCE WITH IMPLEMENTING COST CONTAINMENT MEASURES IN ITS SUBSIDIARIES' PROJECTS?

A. Yes, we do. One notable example is NEET's subsidiary Horizon West Transmission, which, as I noted above, was the first non-incumbent selected by the CAISO through its competitive transmission solicitation process for the Suncrest SVC Project in 2014. Horizon West Transmission proposed and maintained its binding cost cap on the project even after a requirement of undergrounding one mile of 230 kV transmission line was added to the project scope post-award, which caused an incremental price increase of $5 million to the project cost.

Q. ARE THERE QUANTIFIABLE BENEFITS TO CUSTOMERS FROM NEET SOUTHWEST'S PROPOSED PROJECT?

A. Yes, NEET Southwest's Project will provide quantifiable benefits to Kansas and SPP customers. First, as SPP determined through its transmission planning process, the Project itself will result in substantial economic benefits to SPP customers, by significantly reducing congestion on the SPP transmission grid between western Kansas and load centers on the eastern side of the SPP region. Second, NEET Southwest will offer transmission service on the Project line through an open access transmission tariff that will be filed with and subject to the jurisdiction of FERC. Customers that purchase transmission service from the Project are anticipated to be wholesale buyers (utilities, wholesale suppliers, competitive retail suppliers, brokers, and marketers). As a provider of open access transmission services, NEET Southwest is obligated to offer and provide service to all eligible customers on a non-discriminatory basis. Accordingly, NEET Southwest submits that wholesale transmission customers will benefit from additional choices in transmission service through the Project and will have the added benefit of obtaining that service on a non-discriminatory basis.

Third, NEET Southwest's binding cost cap for the Project will result in substantial savings from SPP's originally estimated costs for the competitive portion of the Project. Fourth, NEET Southwest's early in-service date, which is one year before SPP's identified in-service date, will provide approximately $14.5 million in present value production cost [redacted], which results in an additional savings to customers of [redacted]. Sixth, NEET Southwest committed to [redacted] Finally, as Dr. Loomis describes, there will be a number of significant economic benefits from the Project to the state and local economies, including the creation of approximately 998 new jobs during construction of the Project and associated facilities and approximately six to 9.6 new long-term jobs, which will result in an additional $498,000-$716,000 in long-term worker earnings and over $145 million in new economic output during construction and $4.4-$5.1 million in new long-term economic output.

Q. WILL NEET SOUTHWEST SERVE END-USE CUSTOMERS IN KANSAS?

A. No, it will not. NEET Southwest will transfer functional control over the Project to SPP once completed, who in turn will provide unbundled, wholesale transmission service over the Project under the SPP Tariff. NEET Southwest's Annual Transmission Revenue Requirement ("ATRR") will be included in SPP regional transmission charges, a portion of which will be charged to Kansas load-serving entities, which will then charge those costs to their retail customers. Accordingly, NEET Southwest will not directly charge any end-use customers in Kansas for costs from the Project.

Q. HOW WILL THE PROJECT AFFECT RETAIL RATES OF END-USE CUSTOMERS IN KANSAS?

A. The Project will have a *de minimis* impact on Kansas retail customers. Specifically, we conservatively estimate that the Project is likely to result in only a $0.04 increase on the average residential customer's monthly bill in Kansas (based upon an assumed monthly demand of 1,000 kWh). This estimate is based upon the following assumptions and data:

Project ATRR	$8,900,000
SPP 12-CP (MW)	40,040
Assumed Load Factor	65%
Estimated Annual MWh	227,987,760
Price Per MWh	$0.04
Price Per kWh	$0.00004
Average Monthly Household Cost (assuming 1000 kWh per month)	$0.04

Using these assumptions and data, I calculated the average monthly household cost by starting with the Project's ATRR, which is based upon NEET Southwest's estimated ATRR for the first year of the Project.[33] Then, I took the SPP 12 Coincident Peak ("12-CP") of 40,040 MW[34] and multiplied it by 8,760 hours per year and then by an assumed load factor of 65 percent, which results in a total MWh of demand in SPP of 227,987,760 MWh. I then divided NEET Southwest's estimated ATRR of $8,900,000 by the 227,987,760 MWh of demand, which resulted in a cost of $0.04 per MWh. I then converted

[33] As I testified above, NEET Southwest [redacted]

[34] *See* SPP Revenue Requirements and Rates File for January 2022, Reg. & Zonal Average Loads Tab, Column R, Line 50, *at* https://www.spp.org/Documents/66337/RRR%20For%20Bills%20January%202022%20Revenue%20Requirements%20and%20Rates.xlsx (dated Jan. 14, 2022).

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that to a kWh cost of $0.00004 per kWh. To determine the average residential monthly cost, I multiplied the kWh cost by an assumed average monthly demand of 1,000 kWh per month,[35] for a total estimated bill impact of $0.04 per month.

Q. HOW WILL GRANTING NEET SOUTHWEST'S REQUESTED CCN AFFECT COMPETITION IN KANSAS?

A. Granting NEET Southwest a CCN to construct, own, operate, and maintain the Project will encourage and enhance wholesale transmission competition in the State of Kansas. As I explained previously, the proposed Project was a direct result of competition, through the SPP competitive TOSP process. NEET Southwest is the first non-incumbent transmission entity to be selected by SPP as a Designated Transmission Owner under the SPP TOSP. Therefore, granting NEET Southwest's requested CCN to transact business as a utility in the State of Kansas will have a positive effect on transmission competition in the state.

B. THE PROPOSED PROJECT WILL MAXIMIZE THE USE OF KANSAS ENERGY RESOURCES

Q. WILL THE PROPOSED PROJECT MAXIMIZE THE USE OF KANSAS ENERGY RESOURCES?

A. Yes, it will. The SPP 2019 ITP Assessment clearly determined a need for the Project to improve transmission capacity from western Kansas to major SPP load centers in the eastern portion of the SPP region, in order to decrease transmission congestion and maximize the use of generation in western Kansas for the benefit of the SPP grid. The Project will increase the flow of electricity generated in Kansas' Wolf Creek Generating Station to the Blackberry Substation and increase the ability of other energy resources in

[35] Using 1,000 kWh per month is also a conservative assumption, as the U.S. Energy Information Administration ("EIA") has estimated that the average monthly demand per household is closer to 893 kWh per month. *See* U.S. EIA, "How much electricity does an American home use?", at https://www.eia.gov/tools/faqs/faq.php?id=97&t=3 (last visited Feb. 10, 2022).

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western Kansas to deliver to load centers in the eastern part of the State and in western Missouri.

C. THE PROPOSED PROJECT WILL REDUCE THE POSSIBILITY OF ECONOMIC WASTE

Q. WILL GRANTING NEET SOUTHWEST'S REQUESTED CCN REDUCE THE POSSIBILITY OF ECONOMIC WASTE?

A. Yes, for a number of reasons. First, as I described above, and as set forth in the 2019 ITP Assessment, SPP identified a number of significant economic benefits from the Project that will improve efficiency and reduce congestion within SPP. In particular, SPP identified improved production cost benefits from the Project, as well as reduced transmission congestion and improved delivery from generation in western Kansas to load centers.[36] According to SPP's 2019 ITP Assessment, the addition of the Project "will help to levelize system LMPs, low generator LMPs in the west and high load LMPs in the east, and overall system congestion while providing market efficiencies and benefits to ratepayers and transmission customers."[37] SPP also determined that the Project will parallel three major transmission contingencies in the area.

The Project also will reduce the possibility of economic waste because it was the product of the SPP competitive process. As I testified previously, the SPP IEP selected NEET Southwest's bid as the most cost-effective solution to the need for the Project, which was $57.4 million less than SPP's originally estimated costs and 30 percent less than the average bid for the Project. NEET Southwest has committed to implement significant cost containment measures to ensure that the total costs of the Project to ratepayers are

[36] Exhibit BW-3 (2019 ITP Assessment) at § 7.1.1.
[37] *Id.*

consistent with its bid. Therefore, NEET Southwest's Project will reduce construction costs, as well as the overall ATRR over the life of the Project.

In addition, as Mr. Mayers testifies, in considering its preliminary route for the Project, NEET Southwest sought to reduce the socioeconomic and landowner impacts of the Project by paralleling or co-locating the Project with existing transmission lines, roads, and property lines, in addition to maximizing distances from residences and public facilities, to the greatest degree possible.[38]

For each of these reasons, granting NEET Southwest's requested CCN will reduce the possibility of economic waste for the Project.

D. GRANTING NEET SOUTHWEST'S REQUESTED CCN TO CONSTRUCT, OWN, OPERATE, AND MAINTAIN THE PROPOSED PROJECT WILL NOT ADVERSELY AFFECT UTILITY SHAREHOLDERS

Q. HOW WILL GRANTING NEET SOUTHWEST'S REQUESTED CCN FOR THE PROJECT AFFECT PUBLIC UTILITY SHAREHOLDERS?

A. As I understand the Commission's prior evaluation of this criteria, this standard was developed by the Commission in a proceeding addressing a transaction that involved two companies intending to consolidate corporate assets to serve retail customers in Kansas,[39] which is not the scenario here. Nevertheless, to the extent this factor is applicable, I do not believe that NEET Southwest's requested CCN will have any negative impact on public utility shareholders within Kansas.

[38] *See* Mayers Direct Testimony at 14-15.

[39] Docket No. 11-GBEE-624-COC, Direct Testimony of Thomas B. DeBaun, p. 19 (Aug. 19, 2011).

Q. IF THE COMMISSION GRANTS NEET SOUTHWEST'S REQUESTED CCN, WHAT WILL BE THE EFFECT ON NEXTERA ENERGY'S SHAREHOLDERS?

A. To the extent applicable, if the Commission grants the CCN, it will have a positive effect on NextEra Energy's shareholders, by allowing NEET Southwest to build, own, and operate the Project.

E. GRANTING NEET SOUTHWEST'S REQUESTED CCN TO CONSTRUCT, OWN, OPERATE, AND MAINTAIN THE PROPOSED PROJECT WILL NOT ADVERSELY AFFECT THE COMMISSION'S JURISDICTION

Q. HOW WILL GRANTING NEET SOUTHWEST'S REQUESTED CCN FOR THE PROJECT AFFECT THE COMMISSION'S JURISDICTION?

A. Granting NEET Southwest's requested CCN will not adversely affect the Commission's jurisdiction. I understand that, if the Commission grants NEET Southwest a CCN to construct, own, operate, and maintain the Project, the Commission will have ongoing jurisdiction over NEET Southwest's CCN, including the ability to open an investigation at any time if there is a question about whether that certification continues to be in the public interest for Kansas.[40] The Commission will continue to have the ability to effectively regulate NEET Southwest as a transmission-only public utility providing service in the state and to audit NEET Southwest's transmission operations in Kansas to the extent necessary. The Commission will also have jurisdiction over the siting of the proposed Project.

[40] Docket No. 11-GBEE-624-COC, Order Approving Stipulation & Agreement and Granting Certificate, ¶ 61 (Dec. 7, 2012).

F. NEET SOUTHWEST HAS THE FINANCIAL, TECHNICAL, AND MANAGERIAL CAPABILITIES TO CONSTRUCT, OWN, OPERATE, AND MAINTAIN THE PROJECT

Q. DOES NEET SOUTHWEST HAVE THE FINANCIAL, TECHNICAL, AND MANAGERIAL CAPABILITIES TO CONSTRUCT, OWN, OPERATE, AND MAINTAIN THE PROJECT?

A. Yes, as stated throughout my testimony and the testimonies of NEET Southwest's other witnesses, NEET Southwest has the financial, technical, and managerial wherewithal to construct, own, operate, and maintain the Project. NEET Southwest has a dedicated team of employees and contractors with a wealth of technical and managerial knowledge and experience to conduct the work on this Project. And, as Ms. Finnis will testify in more detail, NEET Southwest has the necessary financing to manage and operate this Project.

G. THE PROPOSED PROJECT WILL HAVE A POSITIVE IMPACT ON TRANSMISSION IN OTHER STATES

Q. HOW WILL THE PROPOSED PROJECT IMPACT TRANSMISSION IN OTHER STATES?

A. The Project will benefit transmission in other states. Specifically, the Project will include approximately nine miles of new 345 kV transmission in Missouri, and it will interconnect to the 345 kV Blackberry Substation in Jasper County, Missouri.

More broadly, SPP identified the positive effects of the Project on the SPP grid through its 2019 ITP Assessment, in which it identified significant benefits to the SPP grid from reduced transmission congestion and increased transmission capability from western Kansas east to SPP load centers. As I explained above, these benefits include:

- Addressing "historic and projected congestion on the EHV system" in southeast Kansas and southwest Missouri, as well as "unresolved transmission limits identified in multiple studies";[41]

[41] Exhibit BW-3 (2019 ITP Assessment) at § 4.1.1.1.

- Resolving "multiple 2019 ITP needs and additional issues identified"[42] for the southeast Kansas/southwest Missouri region, and relieving congestion and diverting "bulk power transfers away from the Wolf Creek-Waverly-La Cygne 345 kV line, Wolf Creek 345 kV transformer and downstream 69 kV lines, and allowing bulk power transfers to continue to flow east to major SPP load centers";[43]

- Helping to "levelize system LMPs, low generator LMPs in the west and high load LMPs in the east, and overall system congestion while providing market efficiencies and benefits to ratepayers and transmission customers";[44]

- Providing "additional flexibility for future expansion options, including further expansion into eastern load centers and the opportunity for future seams projects with neighboring regions",[45] which has the potential to expand benefits to the SPP market and transmission in neighboring states; and

- Supporting increased ATC for the SPP footprint, which SPP estimated would generate "additional wheeling revenues of $4-7 million annually."[46]

These benefits will strengthen the overall SPP grid and will provide benefits locally and regionally.

H. NEET SOUTHWEST AND ITS AFFILIATES HAVE A SIGNIFICANT PRESENCE IN KANSAS

Q. PLEASE DESCRIBE NEET SOUTHWEST'S AND ITS AFFILIATES' PRESENCE IN KANSAS.

A. NEET Southwest is part of the NextEra Energy family, which has an established presence in Kansas primarily through its competitive energy subsidiary, NEER. NextEra Energy companies have invested approximately $1.9 billion in Kansas to date. As I testified above, NEET Southwest's sister company, GridLiance HP, jointly owns 29 miles of transmission assets and related substation facilities in Winfield, Kansas with the City of Winfield. The

[42] *Id.* at § 7.1.1.

[43] *Id.*

[44] *Id.*

[45] *Id.*

[46] *Id.*

Commission evaluated NEET's and NextEra Energy's qualifications to own a transmission utility in Kansas just last year through the GridLiance acquisition proceeding in Docket No. 21-GLPE-160-ACQ. And as Mr. Mayers testifies, NEER subsidiaries own and operate ten wind generation facilities in Kansas and operate approximately 231 miles of transmission lines and multiple substations related to these assets.[47] Within the last five years, NextEra Energy subsidiaries have built over 116 miles of 345 kV transmission facilities in the state.

VII. REQUESTS FOR FINDINGS OF NON-APPLICABILITY AND WAIVER

Q. IS NEET SOUTHWEST REQUESTING ANY WAIVERS OR FINDINGS OF NON-APPLICABILITY FROM THE COMMISSION IN THIS APPLICATION?

A. Yes. As described in the Application beginning at page 21, NEET Southwest is requesting findings of inapplicability or waiver for certain sections of the Kansas Code regulating public utilities, where those provisions apply to utilities that provide retail electric service or contemplate some service that is not provided by NEET Southwest (like generation activities). The Commission has found and approved in similar circumstances that these provisions do not apply to transmission-only utilities because the rates and services offered by such utilities are exclusively regulated by FERC.[48] For the reasons provided in the Application, NEET Southwest requests the Commission to find that K.S.A. 66-101b-f, 66-117, 66-128, and 66-128a-128p are inapplicable to NEET Southwest and that waiver is appropriate for K.S.A. 66-1402 and 66-1403.

---

[47] *See* Mayers Direct Testimony at 8.

[48] *See Order Approving Stipulation & Agreement and Addressing Application of Statutes*, Case No. 07-ITCE-380-COC (June 5, 2007) at ¶ 41; *Order Approving Stipulation & Agreement and Granting Certificate*, Case No. 11-GBEE-624-COC (December 7, 2011) at ¶ 22(f) and p. 27, ¶ A.

Q. WHY IS NEET SOUTHWEST REQUESTING A WAIVER OF K.S.A. 66-1402 AND 66-1403?

A. NEET Southwest and the public will benefit from access to the substantial resources and expertise of the NextEra Energy organization. In order to facilitate these benefits, NEET Southwest respectfully requests that the Commission grant the necessary waiver of K.S.A. 66-1402 and 66-1403, so that NEET Southwest is not required to file its affiliate service contracts with the Commission. NEET Southwest will comply with FERC's affiliate transaction rules, discussed previously, which are found at 18 C.F.R. §§ 35.43-.44.

Q. IS GRANTING THESE WAIVERS IN THE PUBLIC INTEREST?

A. Yes. NEET Southwest is rate-regulated by FERC and will not provide any retail electric service in Kansas. There are also a number of significant benefits that NEET Southwest will realize by utilizing its parent and affiliate resources, which benefits will allow it to deliver the Project at a reasonable cost to Kansas and SPP customers. Accordingly, it is appropriate for the Commission to find these statutes inapplicable or waived. Granting the requested relief will reduce confusion and facilitate NEET Southwest's ability to complete the Project on-time and in line with its cost containment commitments to SPP, to the benefit of Kansas customers.

VIII. <u>CONCLUSION</u>

Q. IS THE PROPOSED PROJECT, AND GRANTING NEET SOUTHWEST'S REQUESTED CCN, IN THE PUBLIC INTEREST?

A. Yes. In summary, my testimony and the testimony of NEET Southwest's other witnesses show that the proposed Project will serve the needs identified by SPP at a reasonable cost, and that granting NEET Southwest's requested CCN will serve the public convenience and necessity in Kansas. Granting NEET Southwest's requested CCN will serve and benefit the public interest, as it will allow for construction of the Project at the lowest cost to customers. NEET Southwest's cost containment measures will provide significant cost benefits to SPP customers, and the deep expertise in owning, operating, and maintaining transmission lines of the NextEra Energy organization that NEET Southwest will bring to bear will ensure safe and reliable construction and operation of the Project.

Q. SHOULD THE COMMISSION GRANT NEET SOUTHWEST A LIMITED CCN TO SERVE AS A TRANSMISSION-ONLY UTILITY THAT WILL CONSTRUCT, OWN, AND OPERATE THE PROJECT?

A. Yes. The information provided in my Direct Testimony, and in the testimony of NEET Southwest's other witnesses and supporting exhibits, supports a determination by the Commission to grant NEET Southwest's requested CCN to construct, own, and operate the Project.

Q. SHOULD THE COMMISSION GRANT NEET SOUTHWEST'S REQUESTED RELIEF REGARDING THE WAIVER OR APPLICATION OF CERTAIN STATUTES?

A. Yes. Granting NEET Southwest a waiver of K.S.A. 66-1402 and 66-1403 will ensure that NEET Southwest can utilize the extensive resources and expertise of the NextEra Energy organization, to the benefit of Kansas customers. Further, making a finding of non-applicability for certain statutes addressing retail rate regulation will reduce confusion and facilitate NEET Southwest's ability to complete the Project on-time and in line with its cost containment commitments to SPP, to the benefit of Kansas customers.

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

VERIFICATION

STATE OF FLORIDA)

) ss.

COUNTY OF PALM BEACH)

I, Becky Walding, being duly sworn, on oath state that I am Executive Director, Development, of NextEra Energy Transmission, LLC, and that I have read the foregoing pleading and know the contents thereof, and that the facts set forth therein are true and correct to the best of my knowledge and belief.

By: Becky Walding

Becky Walding

The foregoing pleading was subscribed and sworn to before me this 28th day of February, 2022.

AMY LOWE
Commission # GG 946874
Expires May 11, 2024
Bonded Thru Troy Fain Insurance 800-385-7019

Amy Lowe

Notary Public

My Commission Expires:

____

Exhibit BW-1

Delaware

The First State

I, JEFFREY W. BULLOCK, SECRETARY OF STATE OF THE STATE OF DELAWARE, DO HEREBY CERTIFY THE ATTACHED IS A TRUE AND CORRECT COPY OF THE CERTIFICATE OF FORMATION OF "NEXTERA ENERGY TRANSMISSION SOUTHWEST, LLC", FILED IN THIS OFFICE ON THE FIFTEENTH DAY OF APRIL, A.D. 2014, AT 11:30 O'CLOCK A.M.

Jeffrey W. Bullock, Secretary of State

5516826 8100

AUTHENTICATION: 1293412

140471440

DATE: 04-15-14

You may verify this certificate online at corp.delaware.gov/authver.shtml

State of Delaware
Secretary of State
Division of Corporations
Delivered 11:40 AM 04/15/2014
FILED 11:30 AM 04/15/2014
SRV 140471440 - 5516826 FILE

STATE *of* DELAWARE
LIMITED LIABILITY COMPANY
CERTIFICATE *of* FORMATION

The undersigned, an authorized natural person, for the purpose of forming a limited liability company under the provisions and subject to the requirements of the laws of the State of Delaware (including Chapter 18, Title 6 of the Delaware Code and the acts amendatory thereof and supplemental thereto, and known, identified, and referred to as the "Delaware Limited Liability Company Act"), hereby certifies that:

FIRST: The name of the limited liability company (hereinafter called the "limited liability company") is **NextEra Energy Transmission Southwest, LLC.**

SECOND: The address of the registered office and the name and address of the registered agent of the limited liability company required to be maintained by Section 18-104 of the Delaware Limited Liability Company Act are:

The Corporation Trust Company
1209 Orange Street
Wilmington, DE 19801

Executed this 15th day of April, 2014.

Melissa A. Plotsky
By: Melissa A. Plotsky
An Authorized Person

KRIS W. KOBACH
Secretary of State

Memorial Hall, 1st Floor
120 S.W. 10th Avenue
Topeka, KS 66612-1594
(785) 296-4564

STATE OF KANSAS

April 29, 2014

LINDA MCBRIDE
CORPORATION COMPANY, INC.

RE: NEXTERA ENERGY TRANSMISSION SOUTHWEST, LLC

ID. # 4812004 (USE IN ALL CORRESPONDENCE WITH OUR OFFICE)

Enclosed is certified copy of the foreign limited liability company application for registration in the state of Kansas. Your foreign limited liability company's business entity identification number is at the top of this page. This business entity identification number should be used in all correspondence with our office.

Every foreign limited liability company must file an annual report with our office and pay a filing fee. The annual report and fee are due together on the 15th day of the fourth month following the tax closing month. (For example, if the tax closing month is December, the due date is April 15 of the following year). The annual report may be filed as early as January 1. An annual report is not required if the company has not been incorporated for six months prior to its first tax year end. If the company operates on a tax year end other than the calendar year, you must notify our office in writing prior to December 31.

The annual report may be filed electronically at www.sos.ks.gov or you may obtain a paper form from the Web site.

PLEASE NOTE: For information regarding taxes, contact the Kansas Department of Revenue at (785) 368-8222 or www.ksrevenue.org.

gmc

Business Services: (785) 296-4564
Fax: (785) 296-4570

Web site: www.sos.ks.gov
E-mail: kssos@sos.ks.gov

Elections: (785) 296-4561
Fax: (785) 291-3051

PUBLIC

Exhibit BW-1

4812004

FL 51-10

KANSAS SECRETARY OF STATE

Foreign Limited Liability Company Application

CONTACT: Kansas Office of the Secretary of State

Memorial Hall, 1st Floor
120 S.W. 10th Avenue
Topeka, KS 66612-1594

(785) 296-4564
kssos@sos.ks.gov
www.sos.ks.gov

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051 010
$165.00 3

FILED BY KS SOS
04-29-2014
12:42:18 PM
FILE#: 4812004

03849418

INSTRUCTIONS: *All information must be completed or this document will not be accepted for filing.*
Please read instructions sheet before completing.

1. Name of the limited liability company: *Name of company must match the name on record with the home state*	NextEra Energy Transmission Southwest, LLC
2. State/Country of organization:	Delaware
3. Date of organization in home state:	April 15, 2014 (*Month Day Year*)
4. Began doing business in Kansas:	☒ Upon qualification ☐ ____ *Month Day Year*
5. Name of the resident agent and address of the registered office in Kansas: *Address must be a street address. A P.O. box is unacceptable*	*Name:* The Corporation Company, Inc. *Street Address:* 112 SW 7th Street Suite 3C *City:* Topeka *State:* Kansas *Zip:* 66603
6. Mailing address: *This address will be used to send official mail from the Secretary of State's office*	*Attention Name:* Corporate Governance - LAW/JB *Address:* 700 Universe Blvd. *City:* Juno Beach *State:* FL *Zip:* 33408 *Country:* USA
7. Tax closing month:	December
8. Full nature and character of the business to be conducted in Kansas:	development of energy transmission

9. If management vests with members, please provide the name and address of each member. If management vests with managers, please provide the name and address of each manager:
Do not leave blank

If additional space is needed please provide an attachment

1) NextEra Energy Transmission, LLC
Name
700 Universe Blvd. | Juno Beach | FL | 33408 | USA
Mailing address | *City* | *State* | *Zip* | *Country*

2)
Name

Mailing address | *City* | *State* | *Zip* | *Country*

3)
Name

Mailing address | *City* | *State* | *Zip* | *Country*

4)
Name

Mailing address | *City* | *State* | *Zip* | *Country*

10. The limited liability company hereby consents, without power of revocation, that actions may be commenced against it in the proper court of any county in the state of Kansas where there is proper venue by service of process on the Secretary of State of the State of Kansas; and the limited liability company stipulates and agrees that such service shall be taken and held in all courts to be valid and binding as if due service had been made upon the members of the foreign limited liability company.

11. I declare under penalty of perjury under the laws of the state of Kansas that the foregoing is true and correct and that the company is in good standing in its home state, and I have remitted the required fee.

Melissa A. Plotsky | 4-28-14
Signature of manager or member | *Date (month, day, year)*

Melissa A. Plotsky, Secretary of
NextEra Energy Transmission, LLC, sole member

Delaware

PAGE 1

The First State

I, JEFFREY W. BULLOCK, SECRETARY OF STATE OF THE STATE OF DELAWARE, DO HEREBY CERTIFY "NEXTERA ENERGY TRANSMISSION SOUTHWEST, LLC" IS DULY FORMED UNDER THE LAWS OF THE STATE OF DELAWARE AND IS IN GOOD STANDING AND HAS A LEGAL EXISTENCE SO FAR AS THE RECORDS OF THIS OFFICE SHOW, AS OF THE SEVENTEENTH DAY OF APRIL, A.D. 2014.

AND I DO HEREBY FURTHER CERTIFY THAT THE ANNUAL TAXES HAVE NOT BEEN ASSESSED TO DATE.

I hereby certify this to be a true and correct copy of the original on file.
Certified on this date: April 29, 2014
KRIS W. KOBACH
Secretary of State

Jeffrey W. Bullock, Secretary of State

5516826 8300

140485208

AUTHENTICATION: 1301333

DATE: 04-17-14

You may verify this certificate online at corp.delaware.gov/authver.shtml

<u>Exhibit BW-2</u>

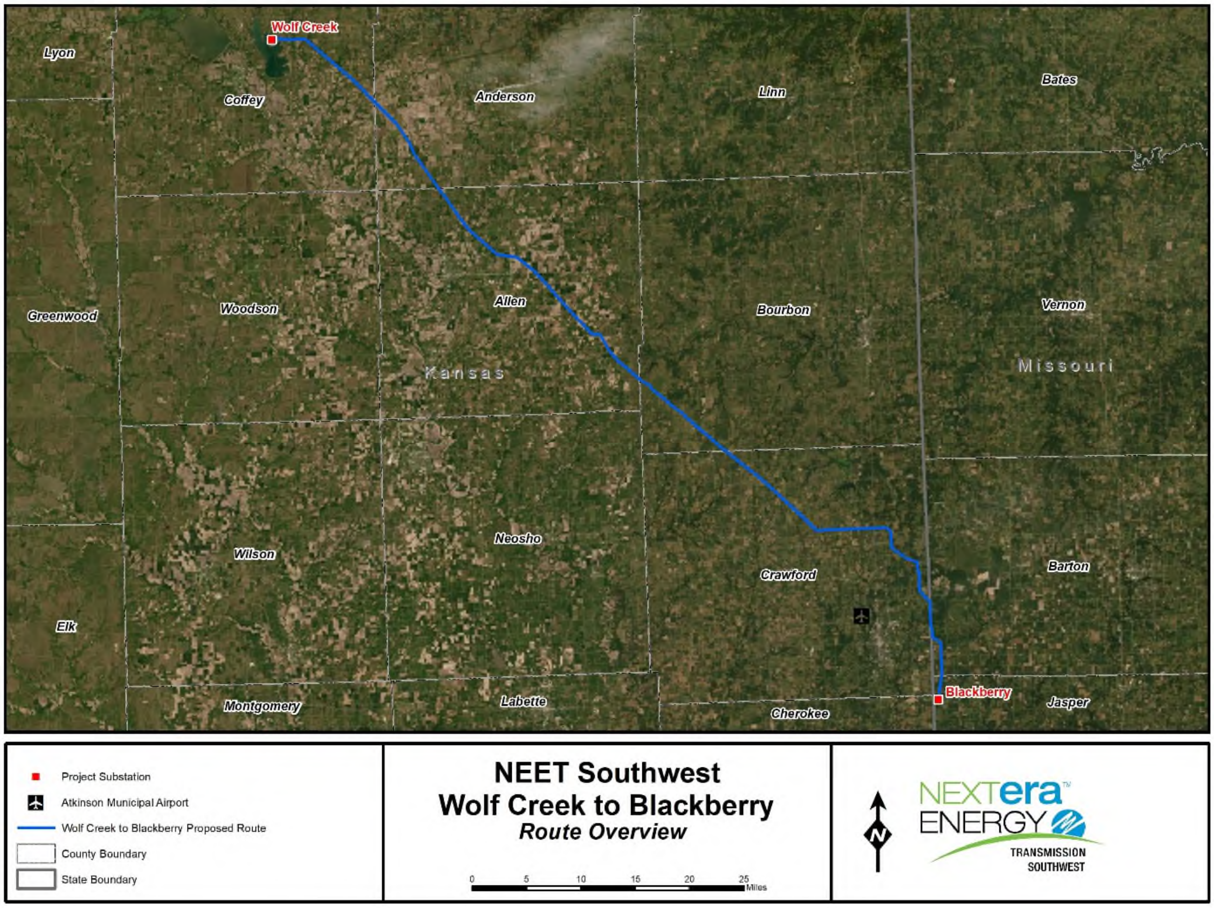

Wolf Creek
Lyon
Coffey
Anderson
Linn
Bates
Greenwood
Woodson
Allen
Bourbon
Vernon
Kansas
Missouri
Wilson
Neosho
Crawford
Barton
Elk
Montgomery
Labette
Cherokee
Blackberry
Jasper
Project Substation
Atkinson Municipal Airport
Wolf Creek to Blackberry Proposed Route
County Boundary
State Boundary
NEET Southwest
Wolf Creek to Blackberry
Route Overview
0 5 10 15 20 25 Miles
N
NEXTera ENERGY
TRANSMISSION SOUTHWEST

Exhibit BW-3

2019 INTEGRATED TRANSMISSION PLANNING ASSESSMENT REPORT

SPP Engineering
Version 1.0
Published 11/06/2019

SPP Southwest Power Pool

REVISION HISTORY

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION	COMMENTS
08/22/2019 v0.1	SPP Staff	Initial Draft Report	Posted for stakeholder review
09/17/2019 v0.2	SPP Staff	Full Draft Report	Posted for ESWG/TWG review
09/27/2019 v0.3	SPP Staff	Final Draft Report	Posted for ESWG/TWG approval
09/30/2019 v0.4	SPP Staff	Updated Final Draft Report: • Marginal energy losses zonal numbers updated (Table 8.9 updated) • ATRR number updated (Tables 8.5, 8.10, 8.11, 8.12 and 8.13 updated) • Infographic updated in Executive Summary	• Table 8.9: Marginal energy losses - zonal numbers updated to align correctly with each zone (regional numbers correct) • ATRR number updated; resulted in updates to the benefit summary tables 8.10, 8.11, 8.12 and 8.13. ATRR update impacted mandated reliability for the cost of reliability projects; resulted in update to Table 8.5

10/01/2019 v.0.5	SPP Staff	Updated Final Draft Report:
		• NTC Recommendations table corrected to match Section 9.1
		• ATRR number updated (Tables 8.12 and 8.13 updated)
			Updated Final Draft Report:
			• Added to NTC Recommendations in Executive Summary table:
			  ○ Replace 21 breakers at Riverside Station 138 kV
			  ○ Replace eight breakers at Southwestern Station 138 kV
			• ATRR number updated (Tables 8.12 and 8.13 updated)

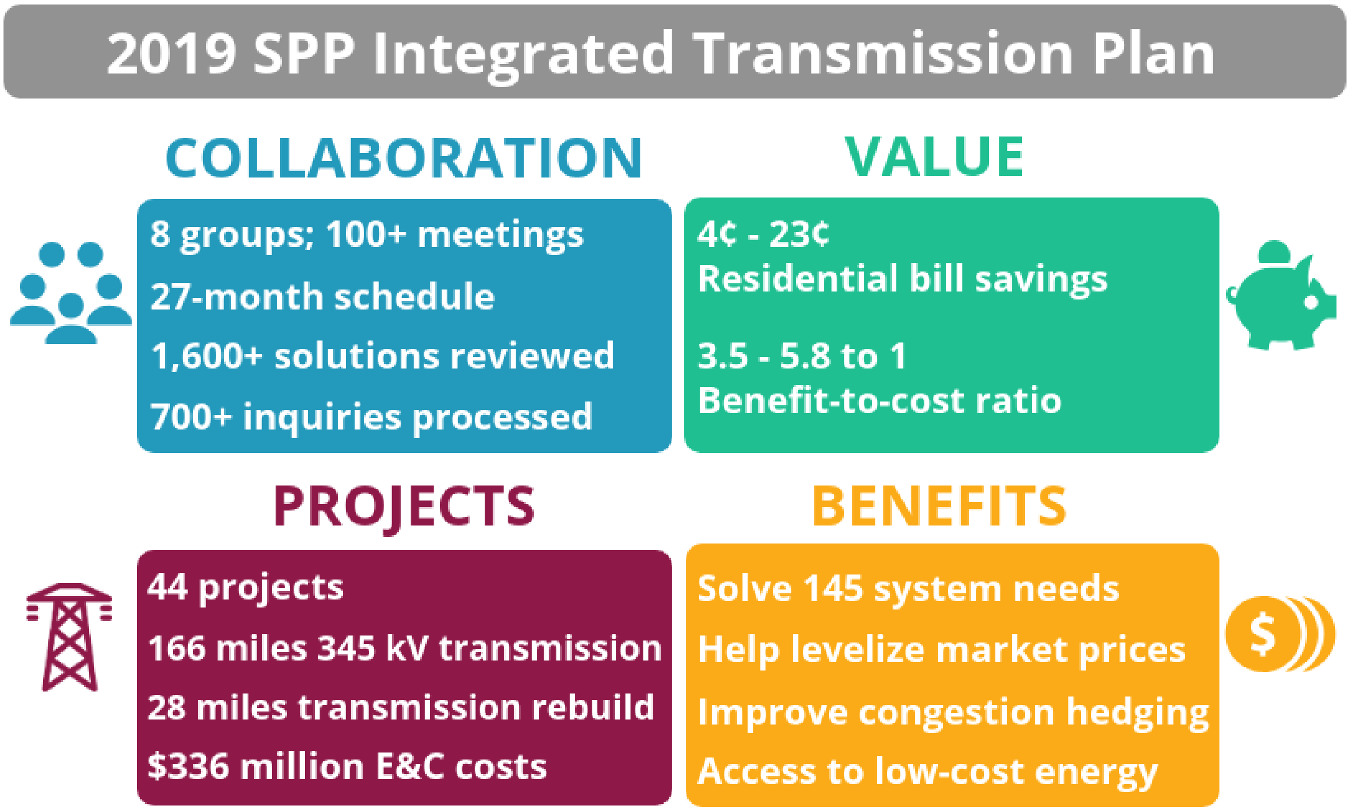
10/01/2019 v0.5	SPP Staff	Final Report	Approved by ESWG/TWG
10/15/2019 v0.5	SPP Staff	Final Report	Approved by MOPC
10/29/2019 v1.0	SPP Staff	Final Report	Approved by SPP Board of Directors

CONTENTS

FIGURES

TABLES

EXECUTIVE SUMMARY



The 2019 Integrated Transmission Plan (ITP) looks ahead 10 years to ensure the SPP region can deliver energy reliably and economically, achieve public policy objectives and maximize benefits to end-use customers. Over 27 months, SPP and its member organizations worked together to forecast and analyze the regional transmission system's economic, reliability, operational and public policy needs. More than 1,600 solutions were evaluated. The analysis resulted in the recommendation to approve 44 transmission projects, including 166 miles of new extra-high-voltage transmission and 28 miles of rebuilt high-voltage infrastructure.

The consolidated portfolio is expected to provide a 40-year benefit-to-cost ratio ranging from 3.5 for Future 1 to 5.8 for Future 2. The net impact to ratepayers is a savings of $0.04 to $0.23 on the average retail residential monthly bill.

This portfolio will mitigate 145 system issues. Reliability projects allow the region to meet compliance requirements and keep the lights on through loading relief, voltage support and system protection. In addition to the reliability projects, the portfolio contains economic projects that help improve the locational marginal price (LMP) levelization, increase of auction revenue right (ARR) awards, and provides access to low-cost energy.

Enabling delivery of low cost renewable resources is a main driver of the EHV projects. Another project driver is reducing price separation in the SPP marketplace, which is caused by congestion on the transmission grid. Rapid renewable expansion has caused increasing pricing disparity between the western and eastern portions of the SPP system. These disparities have created higher average costs for eastern load centers because of congestion and lack of access to less expensive generation. Price differences have only been marginally delayed by new interconnections seeking opportunity in the east. The recommended EHV projects will reduce separation between generator and load locational marginal prices across the region and create reliable transfer capability that will allow the system to realize benefits from low-cost generation.

Previous ITP assessments have been conservative in forecasting the amount of renewable generation expected to interconnect to the grid. When the studies were completed, installed amounts had nearly surpassed 10-year forecasts. Overly conservative forecasts can lead to delayed transmission investment, contributing to persistent congestion. For example, the 2019 economic needs assessment identified five of the ten highest congested flowgates from the 2018 Annual State of the Market Report. For the 2019 ITP assessment, more in-depth analysis was conducted to better forecast renewables development, which will allow the region to proactively build the infrastructure needed to alleviate congestion and provide access to less expensive energy.

Three distinct scenarios were considered to account for variations in system conditions over 10 years. These scenarios consider requirements to support firm deliverability of capacity for reliability (Base Reliability) while exploring rapidly evolving technology that may influence the transmission system and energy industry (Future 1/Future 2). The scenarios included varied wind projections, utility-scale and distributed solar, generation retirements and electric vehicles.

The assessment focused on two target areas in southeast Kansas/southwest Missouri and central/eastern Oklahoma that experience economic congestion. The 2019 ITP consolidated portfolio will address this congestion in addition to improving these areas' steady-state reliability margins, transient stability concerns and unresolved transmission limits.

Project	Area	Type	Project Cost (2019$)	Miles	NTC/ NTC-C
Pryor Junction 138/115 kV transformer	AEPW	R	$9,155,167	-	NTC
Tulsa SE-21 St Tap 138 kV rebuild	AEPW	R	$1,307,802	1.48	NTC
Tulsa SE-S Hudson 138 kV rebuild	AEPW	R	$6,724,237	1.97	NTC
Firth 15MVAR 115 kV capacitor bank	NPPD	R	$3,370,000	-	NTC
Cleo Corner-Cleo Junction 69 kV terminal equipment	WFEC	R	$16,602	-	NTC
Rocky Point-Marietta 69 kV terminal equipment	OKGE/ WFEC	R	$100,000	-	NTC
Bushland-Deaf Smith 230 kV terminal equipment	SPS	R	$1,185,094	-	No
Carlisle-LP Doud Tap 115 kV terminal equipment	SPS	R	$88,924	-	No

Project	Area	Type	Project Cost (2019$)	Miles	NTC/ NTC-C
Deaf Smith-Plant X 230 kV terminal equipment	SPS	R	$1,185,094	-	No
Lubbock South-Jones 230 kV circuit 1 terminal equipment	SPS	R	$88,924	-	No
Lubbock South-Jones 230 kV circuit 2 terminal equipment	SPS	R	$88,924	-	No
Moore-RB-S&S 115 kV terminal equipment	SPS	R	$158,742	-	No
Plains Interchange-Yoakum 115 kV terminal equipment	SPS	R	$158,742	-	No
Potter Co-Newhart 230 kV terminal equipment	SPS	R	$1,185,094	-	No
Marshall County-Smittyville-Baileyville-South Seneca 115 kV rebuild	WERE	R	$17,636,022	16.19	NTC
Getty East-Skelly 69 kV terminal equipment	WERE	R	$114,821	-	NTC
Gypsum 12MVAR 69 kV capacitor bank	WFEC	R	$490,093	-	NTC
Replace 21 breakers at Riverside Station 138 kV	AEPW	R	$16,288,000	-	NTC
Replace eight breakers at Southwestern Station 138 kV	AEPW	R	$4,421,345	-	NTC
Replace one breaker at Craig 161 kV	KCPL	R	$254,000	-	NTC
Replace two breakers at Leeds 161 kV	KCPL	R	$440,000	-	NTC
Replace two breakers at Midtown 161 kV	KCPL	R	$440,000	-	NTC
Replace four breakers at Southtown 161 kV	KCPL	R	$880,000	-	NTC
Replace one breaker at Moore 13.8 kV tertiary bus	NPPD	R	$510,000	-	NTC
Replace two breakers at Hastings 115 kV	NPPD	R	$550,000	-	NTC
Replace five breakers at Canaday 115 kV	NPPD	R	$2,600,000	-	NTC
Replace two breakers at Westmoore 138 kV	NPPD	R	$271,289	-	NTC
Replace three breakers at Santa Fe 138 kV	NPPD	R	$406,935	-	NTC
Replace one breaker at Carlsbad Interchange 115 kV	SPS	R	$552,668	-	NTC
Replace three breakers at Denver City North and South 115 kV	SPS	R	$5,526,680	-	NTC
Replace three breakers at Hale County Interchange 115 kV	SPS	R	$1,658,004	-	NTC
Replace one breaker at Washita 69 kV	WFEC	R	$52,400	-	NTC
Replace 12 breakers at Mooreland 138/69 kV	WFEC	R	$835,850	-	NTC
Replace three breakers at Anadarko 138 kV	WFEC	R	$228,500	-	NTC
Gracemont-Anadarko 138 kV rebuild	WFEC	E	$2,850,000	5.09	NTC
Kingfisher-East Kingfisher Tap 138 kV rebuild	WFEC	E	$1,000,000	2.03	NTC

Project	Area	Type	Project Cost (2019$)	Miles	NTC/ NTC-C
Spearman-Hansford 115 kV terminal equipment	SPS	E	$828,359	1.2	NTC
Lawrence EC-Midland 115 kV terminal equipment	WERE	E	$30,939	-	NTC
New Wolf Creek-Blackberry 345 kV line, new Butler 138 kV phase-shifting transformer	WERE	E	$162,649,008	105.1	**Line**: NTC-C **PST**: No
New Sooner-Wekiwa 345 kV line, Sheffield Steel-Sand Springs 138 kV terminal equipment	AEPW/ OKGE	E	$85,948,123	60.6	NTC-C
Cimarron-Northwest-Matthewson 345 kV terminal equipment	OKGE	E	$369,869	-	NTC
Arnold-Ransom 115 kV terminal equipment, Pile-Scott City-Setab 115 kV terminal equipment	SUNC	E	$3,652,000	-	NTC
Sundown-Amoco Tap 115 kV terminal equipment	SPS	E	$358,281	-	NTC
		Total	**$336,656,532**[1]		

Table 0.1: 2019 ITP Consolidated Portfolio

[1] These costs represent engineering and construction cost provided during the study by SPP stakeholders or its third-party cost estimator.

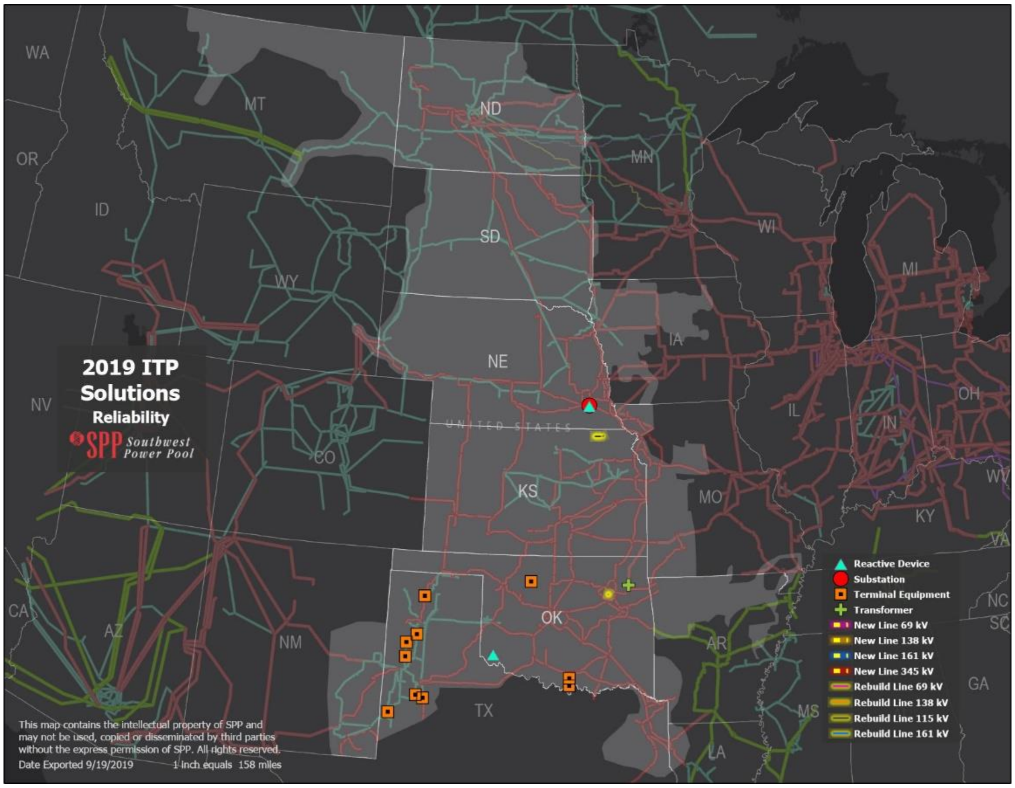


Figure 0.1: 2019 ITP Portfolio – Reliability

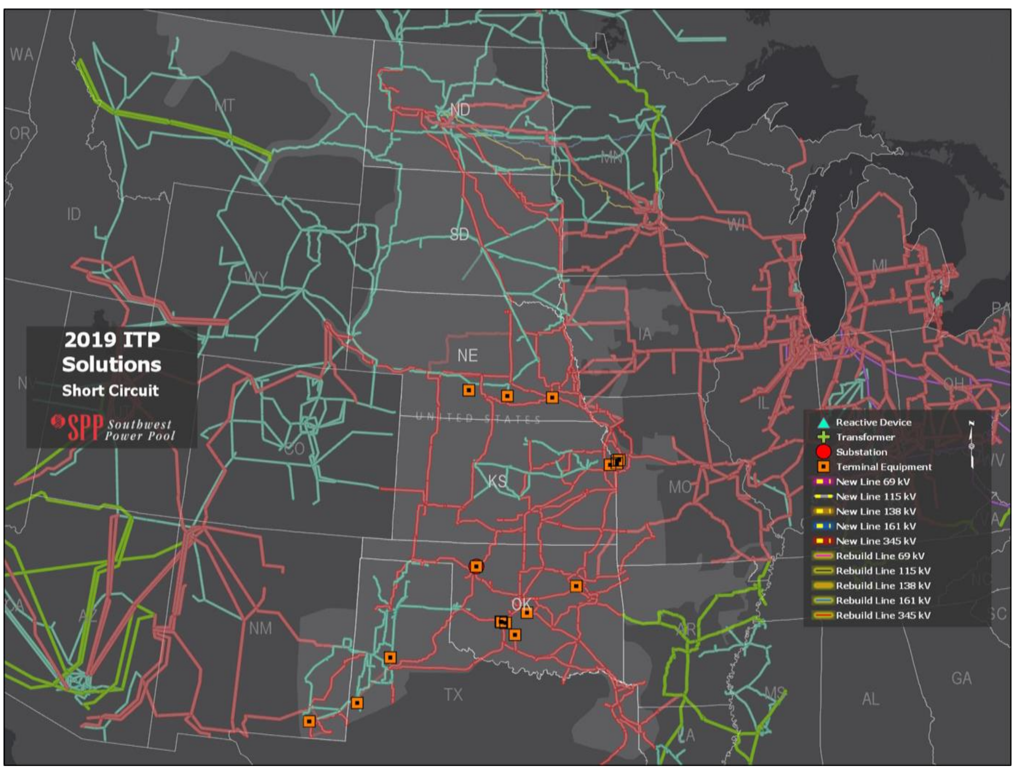


Figure 0.2: 2019 ITP Portfolio - Short Circuit

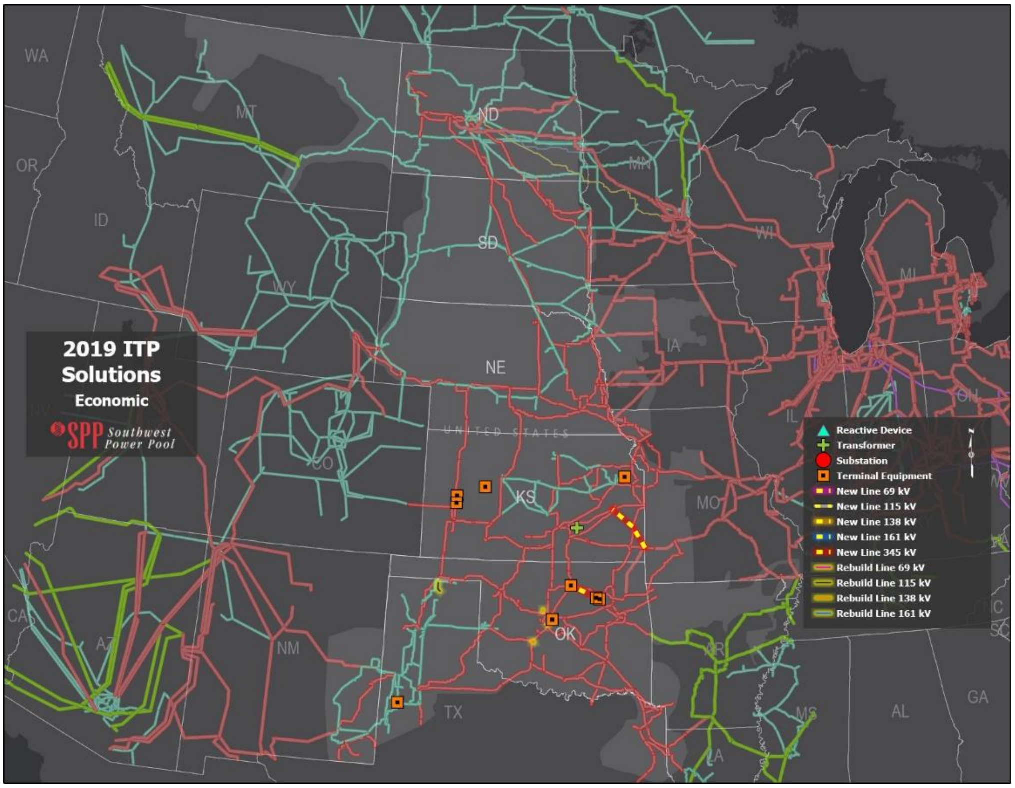


Figure 0.3: 2019 ITP Portfolio - Economic

1 INTRODUCTION

1.1 THE ITP ASSESSMENT

The SPP integrated transmission planning (ITP) process promotes transmission investment to meet near- and long-term reliability, economic, public policy and operational transmission needs[2]. The ITP process coordinates solutions with ongoing compliance, local planning, interregional planning and tariff service[3] processes. The goal is to develop a 10-year regional transmission plan that provides reliable and economic energy delivery and achieves public policy objectives, while maximizing benefits to the end-use customers.

The 2019 ITP assessment is guided by requirements defined in Attachment O to the SPP Open Access Transmission Tariff (tariff), the ITP Manual, and the 2019 ITP Scope. The 2019 ITP is the first completed assessment using the improved ITP process designed by the Transmission Planning Improvement Task Force.

The ITP process is open and transparent, allowing for stakeholder input throughout the assessment. Study results are coordinated with other entities, including those embedded within the SPP footprint and neighboring first-tier entities.

The objectives of the ITP are to:

- Resolve reliability criteria violations.
- Improve access to markets.
- Improve interconnections with SPP neighbors.
- Meet expected load-growth demands.
- Facilitate or respond to expected facility retirements.
- Synergize with the Generator Interconnection (GI), Aggregate Transmission Service Studies (ATSS), and Attachment AQ processes.
- Address persistent operational issues as defined in the scope.
- Facilitate continuity in the overall transmission expansion plan.
- Facilitate a cost-effective, responsive, and flexible transmission network.

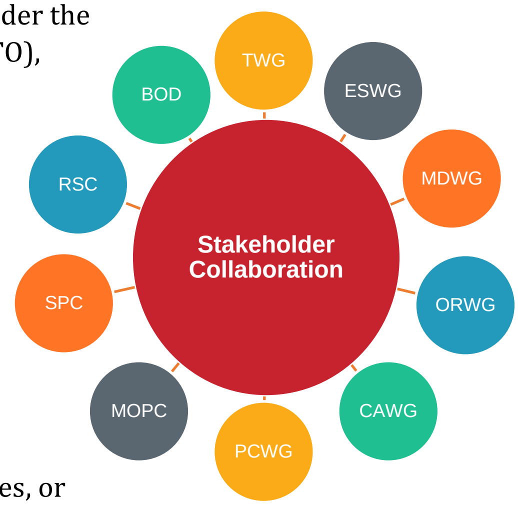
1.2 REPORT STRUCTURE

This report describes the ITP assessment of the SPP transmission system for a 10-year horizon, focusing on years 2021, 2024 and 2029. These years were evaluated with a baseline reliability scenario and two future market scenarios (futures). Sections Model Development and Benchmarking summarize modeling inputs and address the concepts behind this study's approach, key procedural steps in analysis development, and overarching study assumptions. Sections Needs Assessment through Project Recommendations address

[2] The highway/byway cost allocation approving order is Sw. Power Pool, Inc., 131 FERC ¶ 61,252 (2010). The approving order for ITP is Sw. Power Pool, Inc., 132 FERC ¶ 61,042 (2010).
[3] Tariff services include the SPP Aggregate Transmission Service Studies (ATSS) for long-term firm transmission service, Attachment AQ studies for delivery point changes (AQ), and Generator Interconnection (GI) studies for new generator interconnections.

specific results, describe projects that merit consideration, and contain portfolio recommendations, benefits and costs.

Within this study, any reference to the SPP footprint refers to the set of legacy Balancing Authorities (BAs) and transmission owners (TOs) whose transmission facilities are under the functional control of the SPP regional transmission organization (RTO), unless otherwise noted.



The study was guided by the 2019 ITP Scope and SPP ITP Manual, version 2.4. All reports and documents referenced in this report are available on SPP.org. A mapping of supplemental documentation for each section is located in the Appendix of this report.

SPP and its stakeholders frequently exchange proprietary information in the course of any study, and such information is used extensively for ITP assessments. This report does not contain confidential marketing data, pricing information, marketing strategies, or other data considered not acceptable for release into the public domain. This report does disclose planning and operational matters, including the outcome of certain contingencies, operating transfer capabilities, and plans for new facilities that are considered non-sensitive data.

1.3 STAKEHOLDER COLLABORATION

Stakeholders developed the 2019 ITP assessment assumptions and procedures in meetings throughout 2017, 2018, and 2019. Members, liaison members, industry specialists and consultants discussed the assumptions and facilitated a thorough evaluation.

The following SPP organizational groups were involved:

- Transmission Working Group (TWG)
- Economic Studies Working Group (ESWG)
- Model Development Working Group (MDWG)
- Operating Reliability Working Group (ORWG)
- Cost Allocation Working Group (CAWG)
- Project Cost Working Group (PCWG)
- Markets and Operations Policy Committee (MOPC)
- Strategic Planning Committee (SPC)
- Regional State Committee (RSC)
- Board of Directors (Board)

SPP staff served as facilitators for these groups and worked closely with each working group's chairman to ensure all views were heard and considered consistent with the SPP value proposition.

These working groups tendered policy-level considerations to the appropriate organizational groups, including the MOPC and Strategic Planning Committee (SPC). Stakeholder feedback was instrumental in the refinement of the 2019 ITP.

1.3.1 PLANNING SUMMITS

In addition to the standard working group meetings and in accordance with Attachment O of the tariff, SPP held multiple transmission planning summits to elicit further input and provide stakeholders with additional opportunities to participate in the process of discussing and addressing planning topics.

2 MODEL DEVELOPMENT

2.1 BASE RELIABILITY MODELS

2.1.1 GENERATION AND LOAD

Generation and load data in the 2019 ITP base reliability models was incorporated based on specifications documented in the ITP Manual. For items not specified in the ITP Manual, SPP followed the MDWG Procedure Manual. Figure 2.1 and Figure 2.2 below provide a visual for the years two, five, and 10 summer peak and winter peak generation dispatch and load amounts. The generation dispatch amounts are provided by fuel type for all base reliability models that are part of the ITP assessment. Renewable dispatch amounts are based on historical averages for resources with long-term firm transmission service for the summer and winter seasons. For the light load models, all wind resources with long-term firm transmission service were dispatched, with remaining generation needs coming from conventional resources. In the base reliability models, all entities are required to meet their non-coincident peak demand with firm resources.

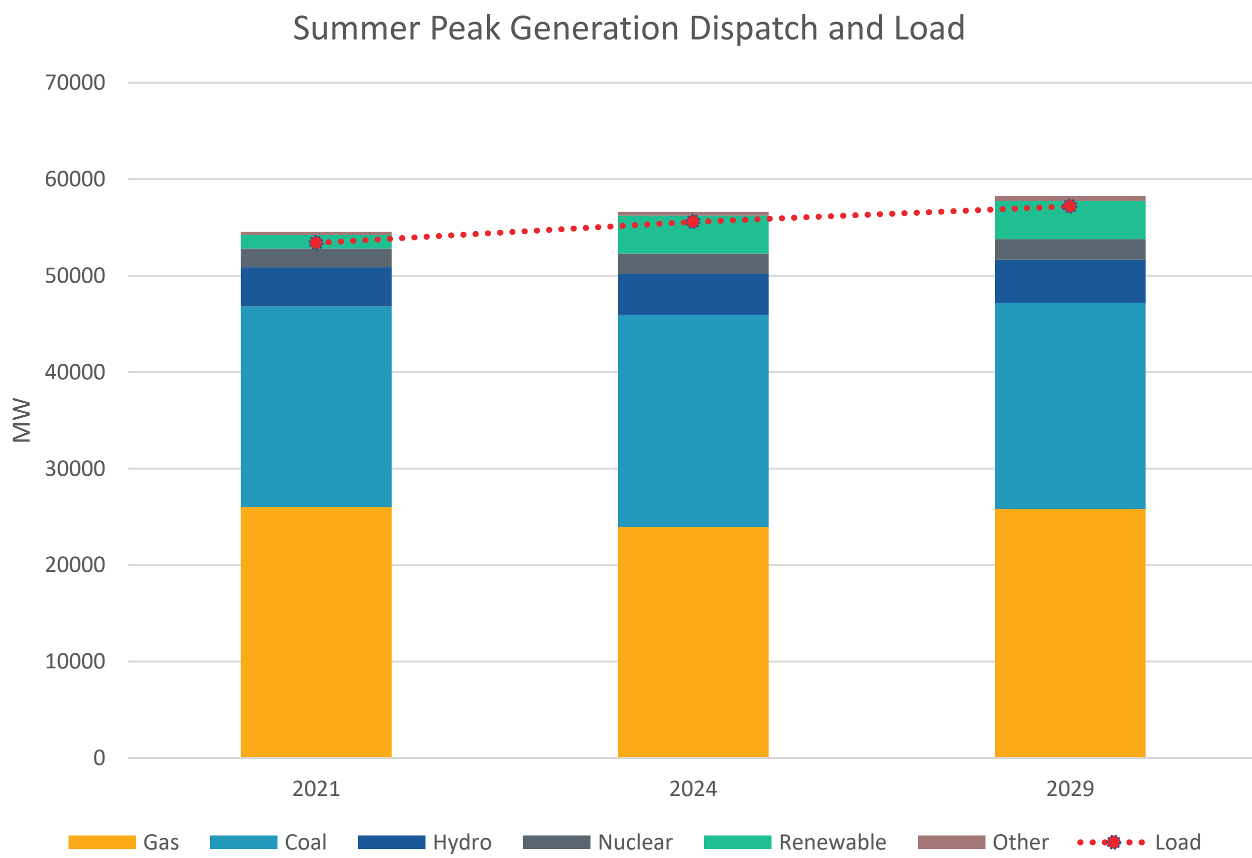


Figure 2.1: 2019 ITP Base Reliability Summer Generation Dispatch and Load

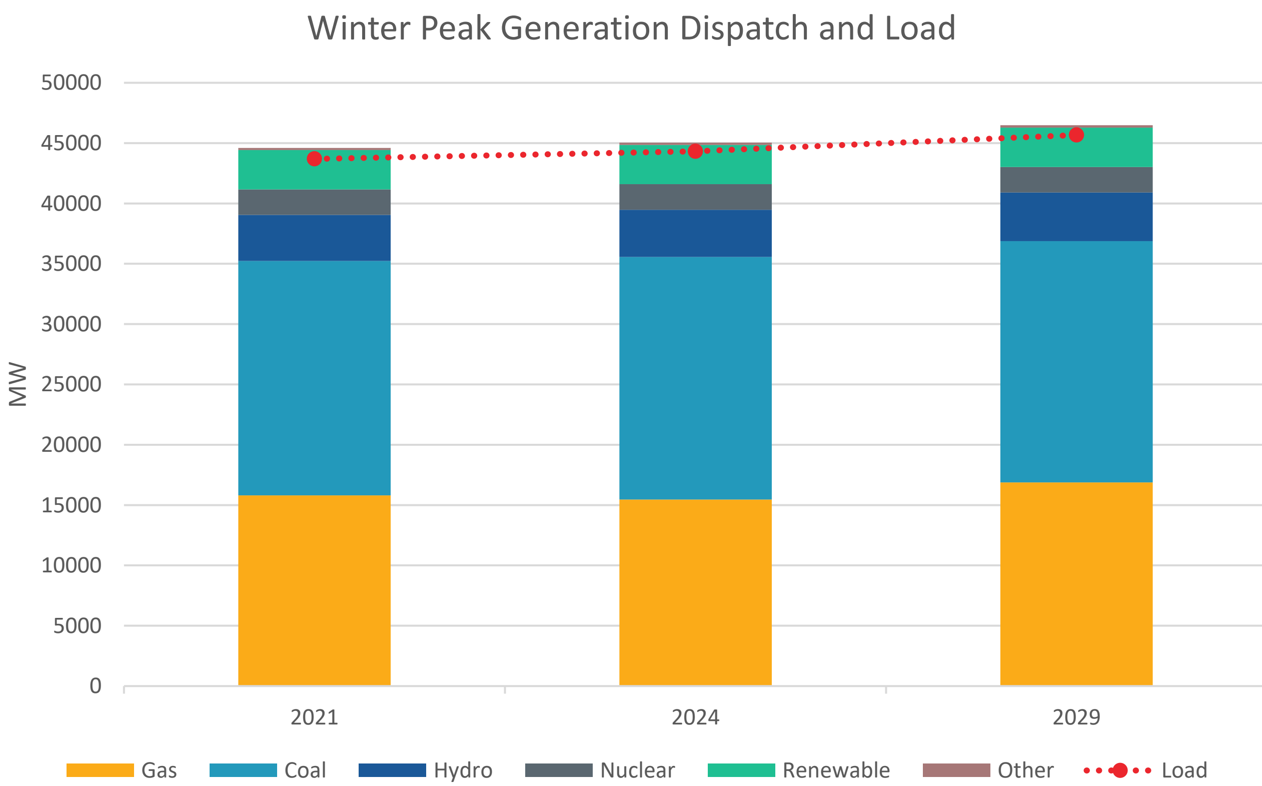


Figure 2.2: 2019 ITP Base Reliability Winter Generation Dispatch and Load

2.1.2 TOPOLOGY

Topology data in the 2019 ITP base reliability models was incorporated based on specifications documented in the ITP Manual. For items not specified in the ITP Manual, SPP followed the MDWG Procedure Manual. The topology for areas external to SPP were consistent with the 2017 Eastern Interconnection Reliability Assessment Group (ERAG) Multi-regional Modeling Working Group (MMWG) model series.

2.1.3 SHORT-CIRCUIT MODEL

A year-two, summer peak, short-circuit model was developed for short-circuit analysis. This short-circuit model has all modeled generation and transmission equipment in service to simulate the maximum available fault current. This model was analyzed in consideration of the North American Electric Reliability Corporation (NERC) TPL-001 standard.

2.2 MARKET ECONOMIC MODEL

2.2.1 MODEL ASSUMPTIONS AND DATA

2.2.1.1 Futures Development

The SPC gave the ESWG policy-level direction on developing the ITP futures, which the ESWG incorporated into discussion of detailed drivers, forming the basis of the potential futures.

The ESWG and additional stakeholders developed a list of drivers and assumed the probability of each driver's occurrence. The list and probabilities were based on each participant's own expectation of future trends and their potential impact to the energy industry and transmission planning efforts. The initial drivers considered for this analysis were:

- Wind and solar capacity additions
- Peak and energy demand growth rates
- Natural gas prices
- Coal prices
- Emissions prices
- Generator retirements
- Environmental regulations
- Demand response
- Distributed generation
- Energy efficiency
- Renewable exports
- Increased renewable capacity factors
- Storage

This initial list of drivers was categorized by description and model implementation synergies to create six potential futures to be studied. SPP staff worked with the ESWG to build a proposal for the reference case and two additional candidate futures[4]: emerging technologies and renewables. These futures were further refined by the ESWG, with input from the SPC and TWG, into two futures to be assessed. The MOPC approved both futures in October 2017.

2.2.1.1.1 Future 1: Reference Case

The reference case future reflects the continuation of current industry trends and environmental regulations. Generally, coal and gas-fired generators over the age of 60 were assumed to be retired, but SPP stakeholders gave input on exceptions to that criteria. Long-term industry forecasts were used for natural gas and coal prices. Solar and wind additions exceeded renewable portfolio standards (RPS) due to economics, public appeal, and the anticipation of potential policy changes.

2.2.1.1.2 Future 2: Emerging Technologies

The assumptions that electric vehicles, distributed generation, demand response, and energy efficiency will impact energy growth rates drove the emerging technologies future. Coal and gas-fired generators over the age of 60 were assumed to be retired. As in the reference case future, this future assumed no changes to current environmental regulations and leveraged long-term industry forecasts for natural gas and coal prices. This future assumes higher solar and wind additions than the reference case due to advances in technology that decrease capital costs and increase energy conversion efficiency.

Table 2.1 summarizes the drivers and how they were considered in each future.

[4] Other futures discussed but not chosen: clean energy, robust economy, and low demand.

	Drivers				
Key Assumptions	**Reference Case**			**Emerging Technologies**	
	2021	**2024**	**2029**	**2024**	**2029**
Peak Demand Growth Rates	As submitted in load forecast	As submitted in load forecast		As submitted in load forecast	
Energy Demand Growth Rates	As submitted in load forecast	As submitted in load forecast		Increase due to electric vehicle growth	
Natural Gas Prices	Current industry forecast	Current industry forecast		Current industry forecast	
Coal Prices	Current industry forecast	Current industry forecast		Current industry forecast	
Emissions Prices	Current industry forecast	Current industry forecast		Current industry forecast	
Fossil Fuel Retirements	Age-based 60+, subject to stakeholder input	Age-based 60+, subject to stakeholder input		Age-based, 60+	
Environmental Regulations	Current regulations	Current regulations		Current regulations	
Demand Response[5]	As submitted in load forecast	As submitted in load forecast		As submitted in load forecast	
Distributed Generation (Solar)	As submitted in load forecast	As submitted in load forecast		+300MW	+500MW
Energy Efficiency	As submitted in load forecast	As submitted in load forecast		As submitted in load forecast	
Export Lines	No	No		No	
New/Re-Powered Renewables	Increased capacity factor	Increased capacity factor		Increased capacity factor	
Storage	None	None		None	
Total Renewable Capacity					
Solar (GW)	0.25	3	5	4	7
Wind (GW)	18.8	24.2	24.6	27	30

Table 2.1: Future Drivers

[5] As defined in the MDWG Model Development Procedure Manual

2.2.1.2 Load and Energy Forecasts

The 2019 ITP load review focused on load data through 2029. The load data was derived from the base reliability model set, and stakeholders were asked to identify/update the following parameters:

- Forecasted system peak load (MW)
- Annual energy (GWh) consumed[6]
- Loss factors
- Load factors
- Load demand group assignments

The ESWG- and TWG-approved load review was used to update the load information in the market economic models. Figure 2.3 shows the total coincident peak load for all study years. Figure 2.4 shows the monthly energy per future for all study years (2021, 2024, and 2029).

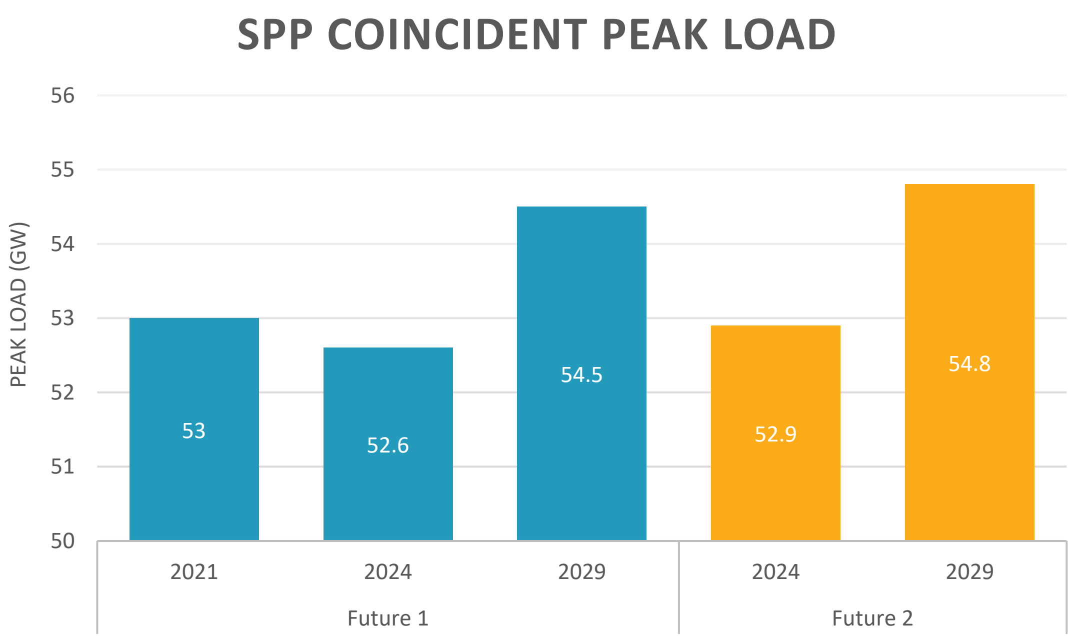


Figure 2.3: Coincident Peak Load

[6] Base annual energy requirements for both futures were reviewed via load factor percentages only. Additional annual energy amounts projected for Future 2 energy growth assumptions were reviewed by stakeholders.

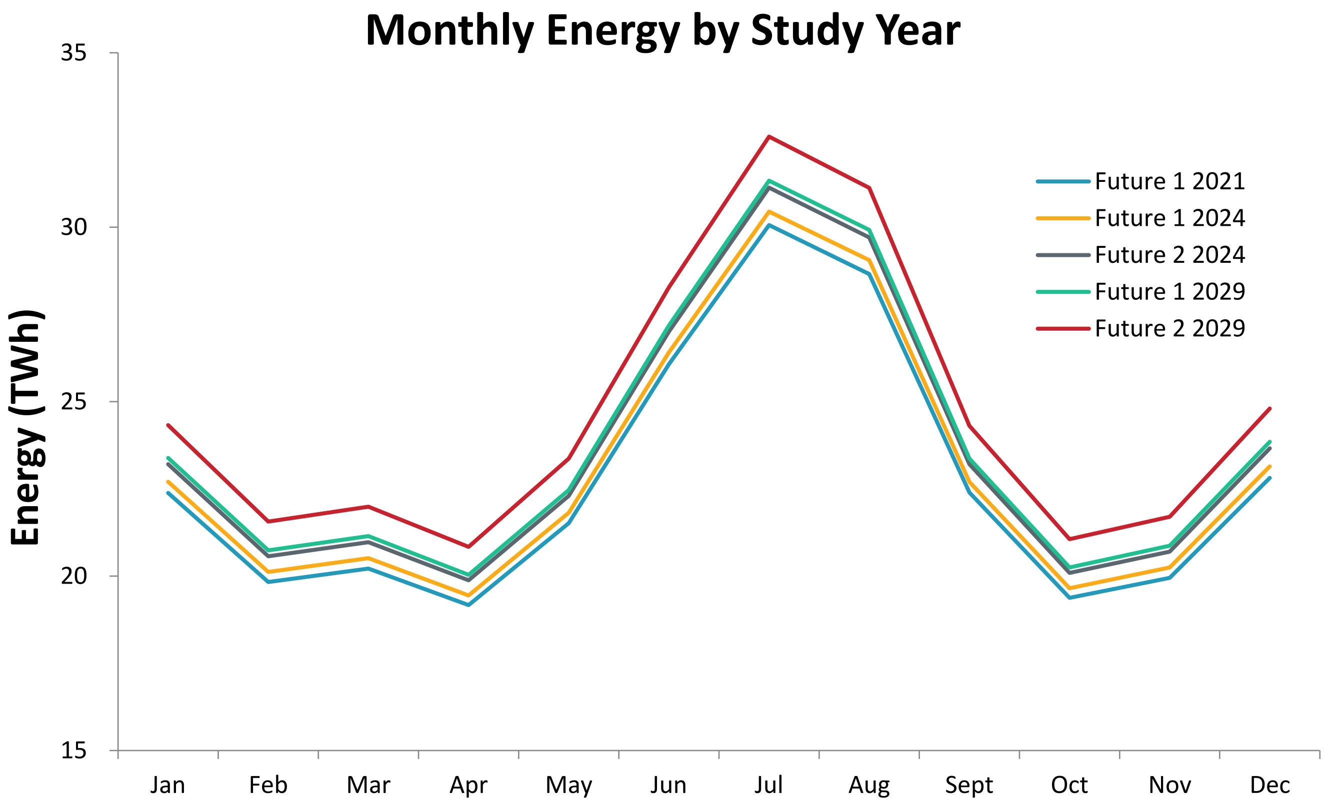


Figure 2.4: 2019 ITP Annual Energy

2.2.1.3 Renewable Policy Review

Renewable policy requirements enacted by state laws, public power initiatives and courts are the only public policy initiatives considered in this ITP via the renewable policy review. These requirements are defined as percentages and outlined in the ITP manual. The 2019 ITP renewable policy review focused on renewable requirements through 2029.

2.2.1.4 Generation Resources

Existing generation data originated from the ABB Strategist (generation expansion software) fall 2016 reference case and was supplemented with SPP stakeholder information provided through the SPP Model on Demand (MOD) tool and the generation review.

Figure 2.5 and Figure 2.6 detail the annual energy and nameplate capacity by unit type for 2021.

In addition to resources accepted in the base reliability models, stakeholders were given the chance to request additional generation resources in the ITP models through the Resource Additional Request (RAR) process. As a result of the RAR process, 860 MW of wind generation was added to the market economic models; 660 MW of the additional wind was included in the Year-two model.

Generator operating characteristics, such as operating and maintenance (O&M) costs, heat rates, and energy limits were also provided for stakeholders to review.

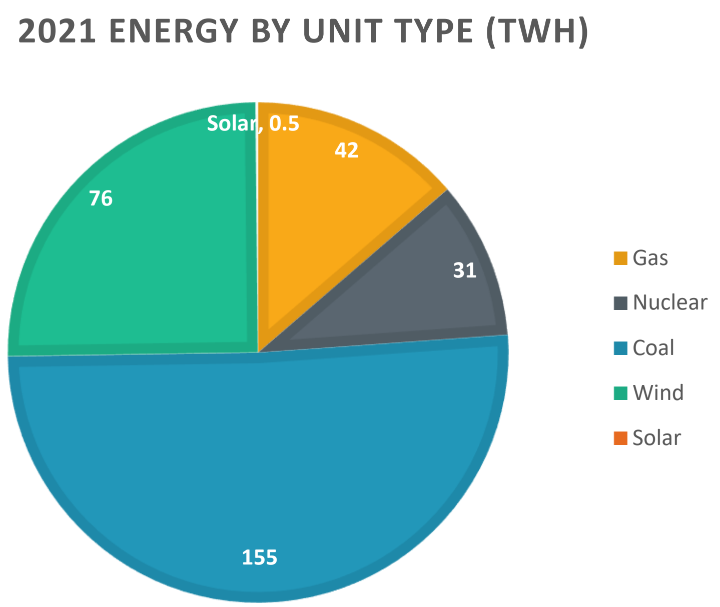


Figure 2.5: 2021 Energy by Unit Type

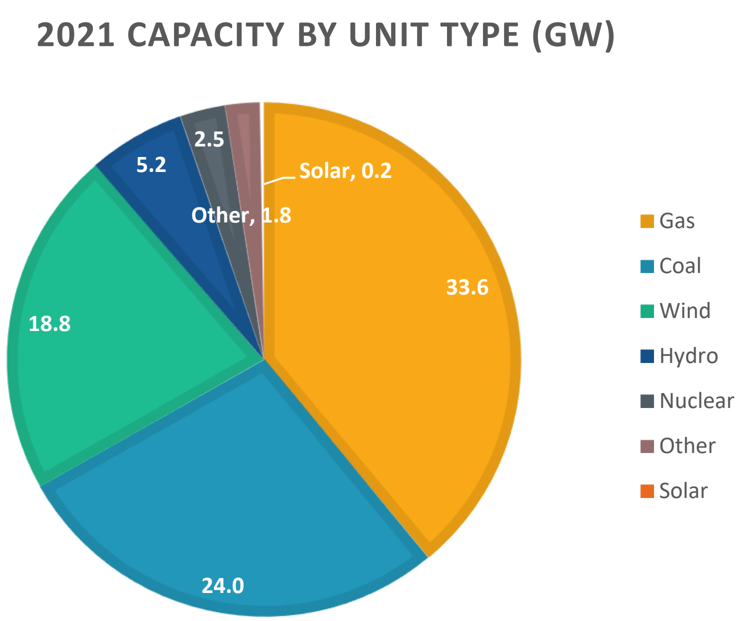


Figure 2.6: 2021 Capacity by Unit Type

Figure 2.7 identifies the amount of retired generation based upon the reference case provided by ABB. The figure reflects both real world retirement not yet included in in the ABB reference case as well as the retirements due to the assumptions within each future.

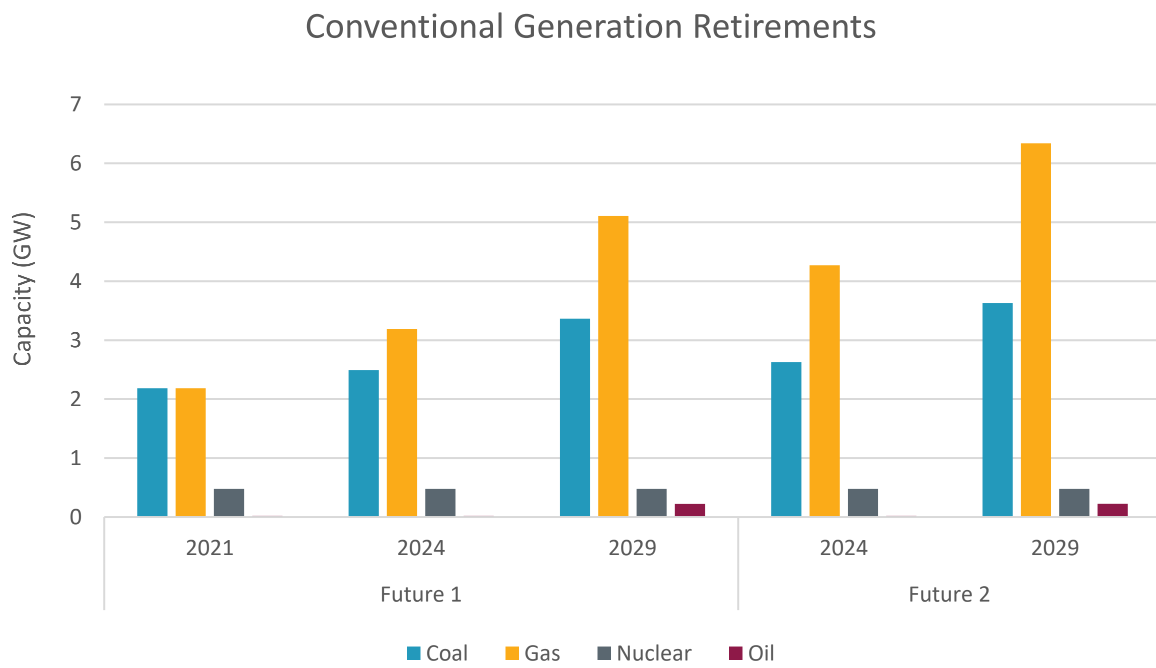


Figure 2.7: Conventional Generation Retirements

2.2.1.5 Fuel Prices

The ABB Strategist fall 2016 reference case and ABB Strategist natural gas fundamental forecast (for long-term price projections) were utilized for the fuel price forecasts. Figure 2.8 shows the annual average natural gas and coal prices for the study horizon. Between 2020 and 2029, these prices increase from \$3.14 to \$5.07 (~5.5% compound average escalation), \$2.20 to \$2.80 (~2.7% compound average escalation) and \$2.20 to \$2.80 (~2.7% compound average escalation) for natural gas and coal, respectively.

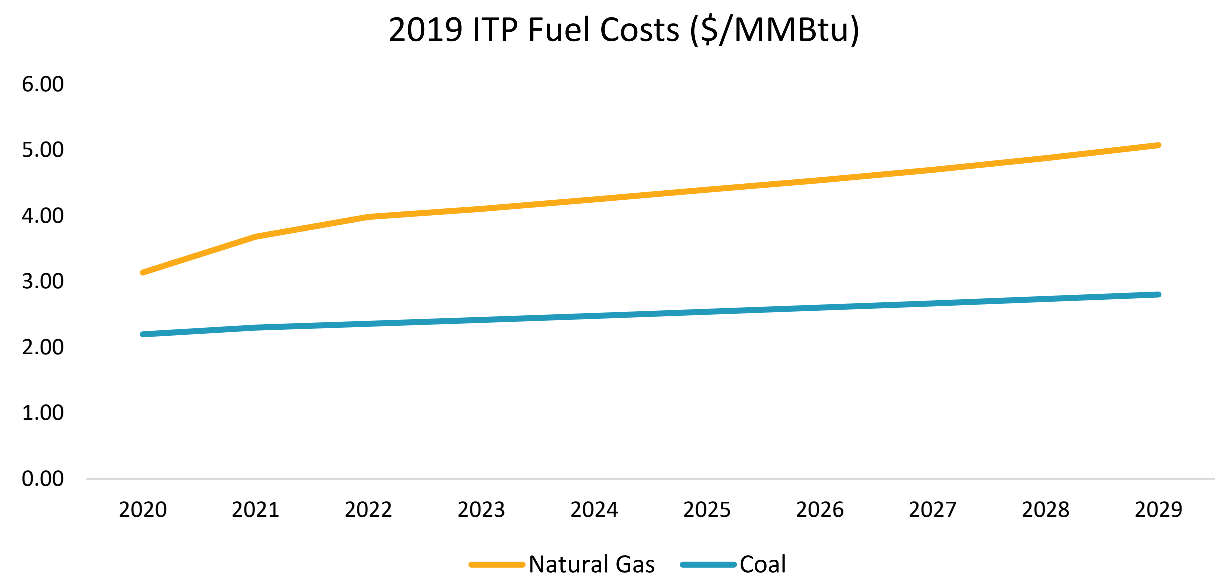


Figure 2.8: ABB Fuel Annual Average Fuel Price Forecast

2.2.2 RESOURCE PLAN

A key component of evaluating the transmission system for a 10-year horizon is to identify the resource outlook for each future. Due to changing load forecasts, resource retirements and a fast-changing mix of resource additions, the SPP generation portfolio will not be the same in 10 years as it is today. SPP staff developed renewable and conventional resource expansion plans for each future and study year to meet projected policy mandates and goals, expected renewable and emerging technology projections as approved in the 2019 ITP futures, and resource reserve margin requirements.

2.2.2.1 Renewable Resource Expansion Plan

The renewable resource expansion plan involves qualitatively forecasting the renewable levels to be included in the assessment; this was accomplished while developing the 2019 ITP scope with stakeholders. For utility-scale solar, the projections for the assessment are consistent with National Renewable Energy Laboratory's *2016 Annual Technology Baseline* standard scenario projections, specific member's integrated resource plan projections, SPP generation interconnection (GI) requests for utility-scale solar, and SPP stakeholder expectations that solar will be added in the future based on its accredited capacity value.

Wind projections in the near term are consistent with historic installation trends (when production tax credits are active), SPP's GI requests for wind, and specific member's public wind addition announcements. The wind projections after the expiration of production tax credits are consistent with wind development growth rates of 1% for Future 1, keeping pace with load growth rates. A wind development growth rate of 2% for Future 2Future 2 marginally outpaces load growth rates.

Each utility was analyzed to determine if the assumed renewable mandates and goals identified by the renewable policy review could be met with existing generation and initial resource projections for 2024 and 2029. If a utility was projected to be unable to meet requirements, additional resources were assigned to the utilities from the total projected renewable amounts to meet the levels specified above. For states with an RPS that could be met by either wind or solar generation, a ratio of 80% wind additions to 20% solar additions was utilized. This split is representative of the active GI queue requests for wind and solar resources.

The incremental renewables assigned to meet renewable mandates and goals in the SPP footprint by 2029 were 212 MW in Future 1 and 222 MW in Future 2. Figure 2.9 shows renewable generation added in each future and study year.

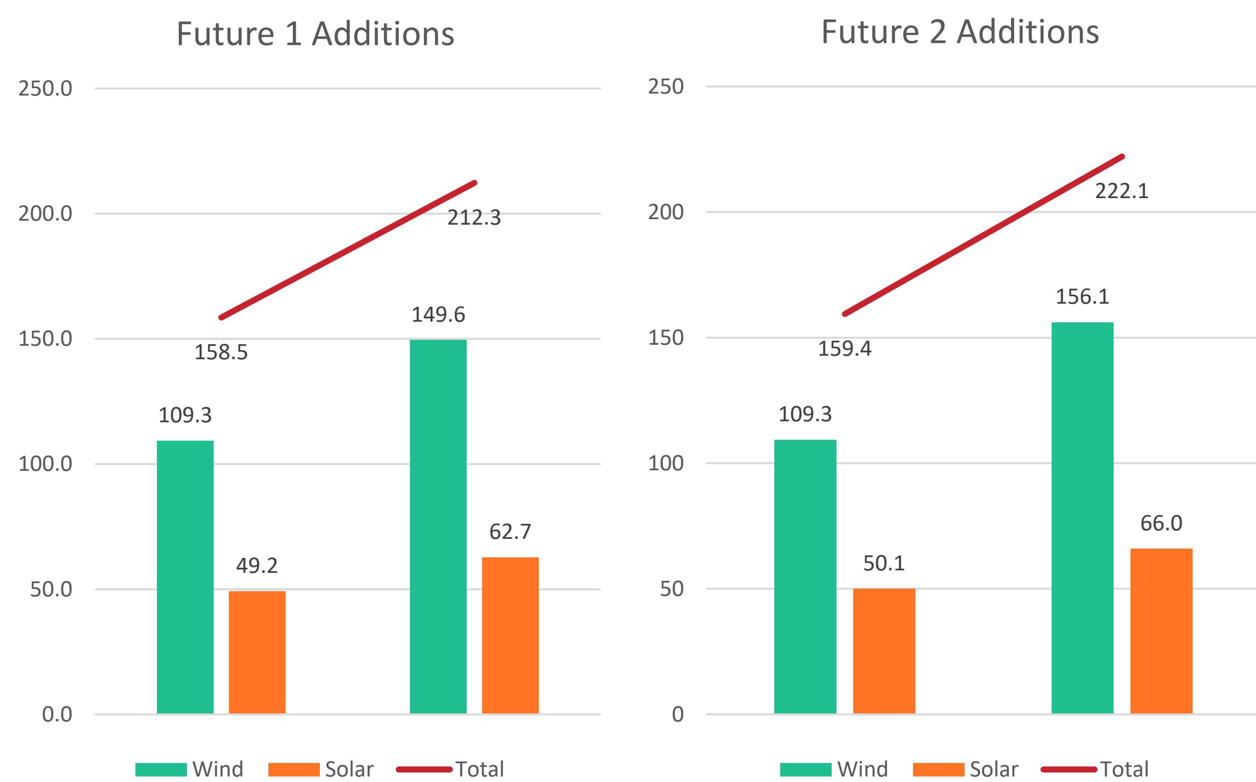


Figure 2.9: SPP Renewable Generation Assignments to meet Mandates and Goals

After ensuring mandates and goals are met by allocating renewables, SPP staff further assigned ownership and allocated the 2019 ITP projected renewable capacity to each pricing zone.

Projected solar additions were assigned based on the load-to-ratio share for each pricing zone. Projected wind additions were allocated to deficient zones to maximize the available accreditation of renewables for each zone, up to the zonal renewable cap defined in the study scope. The order in which resources were accredited was:

- Existing generation
- Policy wind and solar additions
- Projected solar additions
- Projected wind additions
- Conventional additions

2.2.2.2 *Conventional Resource Expansion Plan*

The renewable resource expansion plan for each future was utilized as an input to the corresponding conventional resource expansion plan to ensure appropriate resource adequacy within the SPP footprint. ABB Strategist software was used to develop the conventional resource expansion plan for each future, assessing a 20-year horizon.

After using expected renewables and emerging technologies, conventional resource expansion plans were developed to meet the 12% reserve margin requirement set by SPP Planning Criteria[7]. Projected reserve margins were calculated for each pricing zone using existing generation, projected renewable generation, and load projections through 2039. Resource expansion plans for capacity requirements aggregated to a pricing zone level achieves an appropriate level of assumed power purchase agreements (PPAs) and joint ownership of resources between load-serving entities. Each zone that was not yet meeting its minimum reserve requirement was assigned conventional resources in 2024 and 2029 of both futures.

Nameplate conventional generation capacity assigned to utilities is counted toward each zone's capacity margin requirement. Wind and solar capacity, being intermittent resources, were included at a percentage of nameplate capacity, in accordance with the calculations in SPP Planning Criteria 7.1.5.3. SPP stakeholders were surveyed for feedback on accreditation percentages for existing renewable capacity.

In the analysis of future conventional capacity needs, available resource options were combined cycle (CC) units, fast-start combustion turbine (CT) units, and reciprocating engines. Generic resource prototypes from Lazard's Levelized Cost of Energy Analysis – Version 10.0[8] were utilized. These resource prototypes define operating parameters of specific generation technologies to determine the optimal generation mix to add to the region.

CTs were the primary technology selected in Futures 1 and 2 to meet capacity requirements. Future 1 included the addition of one reciprocating engine.

While both futures represent normal load growth, more resource additions are needed in future two due to the additional unit retirements and increased energy demand growth rates.

Table 2.2 shows the total nameplate generation additions by future and study year to meet futures definitions and resource adequacy requirements. Figure 2.10 shows the nameplate generation additions by future, study year, and capacity type for the SPP region.

	Future 1	Future 2
2024	9.5 GW	11.5 GW
2029	17.0 GW	22.7 GW

Table 2.2: Total Nameplate Generation Additions by Future and Study Year

[7] SPP Planning Criteria
[8] Lazard's Levelized Cost of Energy Analysis - Version 10.0

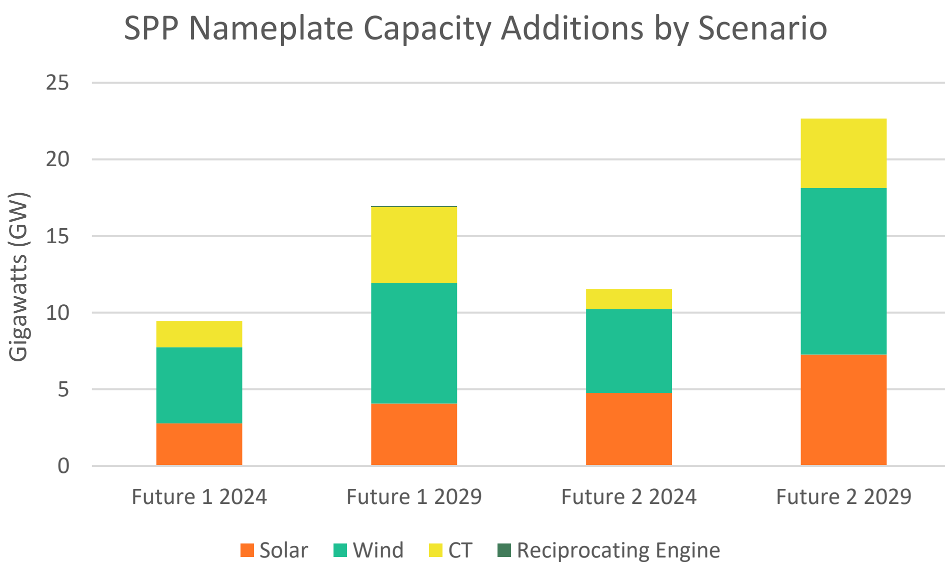


Figure 2.10: Nameplate Capacity Additions by Future and Year

Table 2.3 shows the total accredited generation additions by future and study year. Figure 2.11 shows accredited generation additions by future, study year, and technology for the SPP region.

	Future 1	Future 2
2024	4.7 GW	5.7 GW
2029	9.4 GW	11.3 GW

Table 2.3: Total Accredited Generation Additions by Future and Study Year

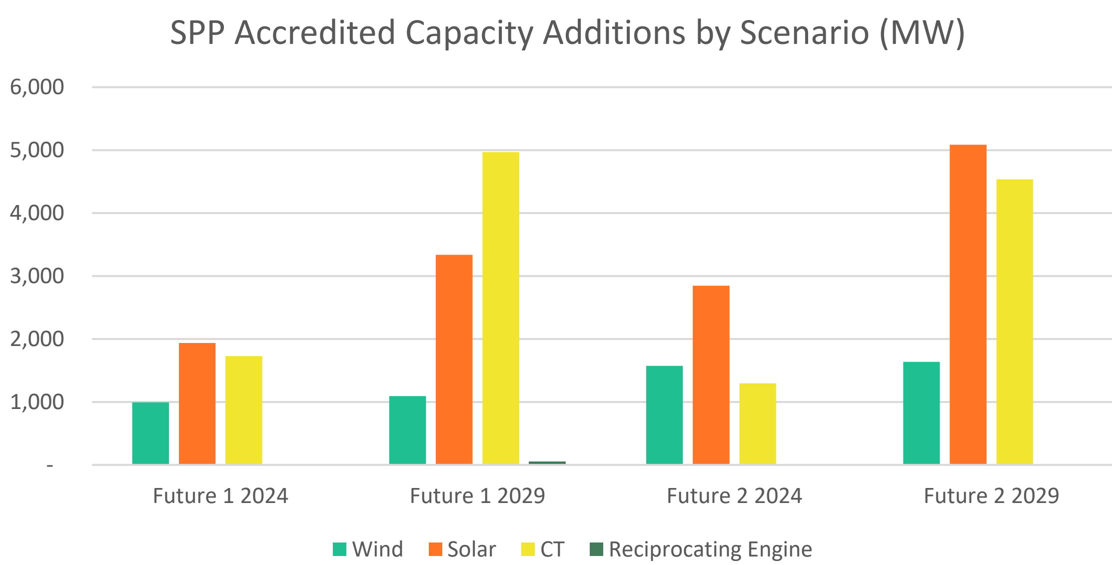


Figure 2.11: Accredited Capacity Additions by Scenario

2.2.2.3 Siting Plan

SPP sited projected renewable and conventional resources according to various site attributes for each technology[9].

Distributed solar generation, an assumption in Future 2 only, was allocated to the top 10% of load buses for each load area on a pro rata basis utilizing load review data. SPP stakeholder feedback was considered in the selection of sites for this technology. Figure 2.12 and Figure 2.13 show the selected sites and allocation of distributed solar capacity across the SPP footprint.

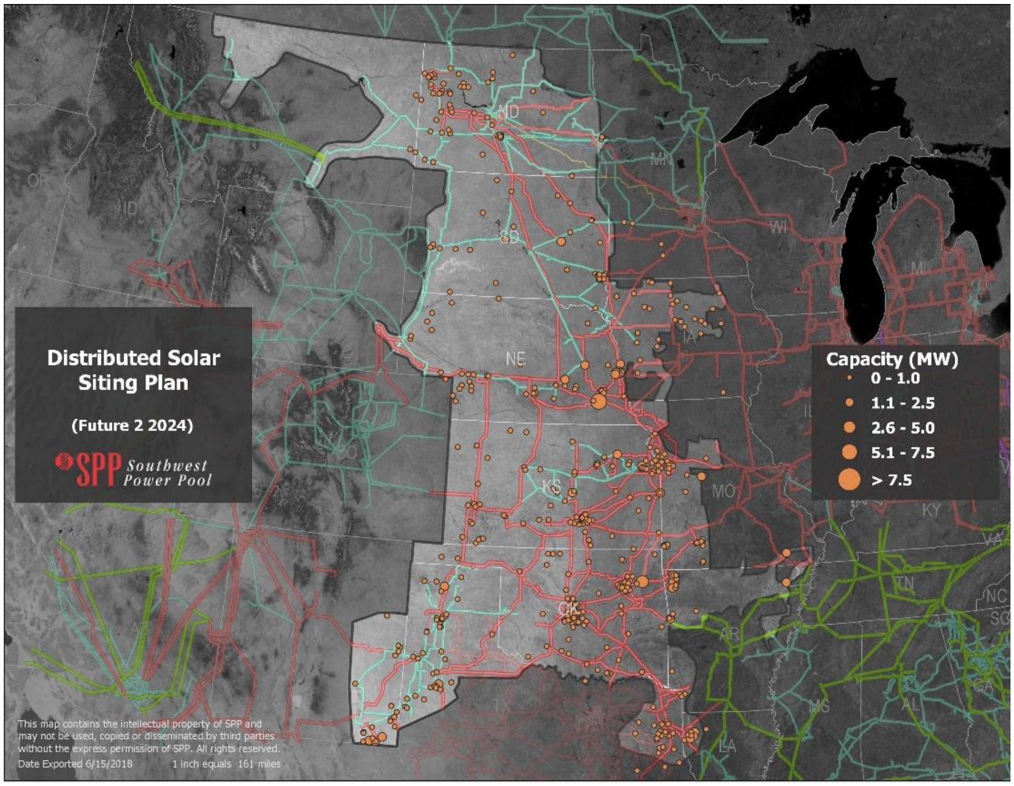


Figure 2.12: 2024 Future 2 Distributed Solar Siting Plan

[9] Documented in the ITP Resource Siting Manual

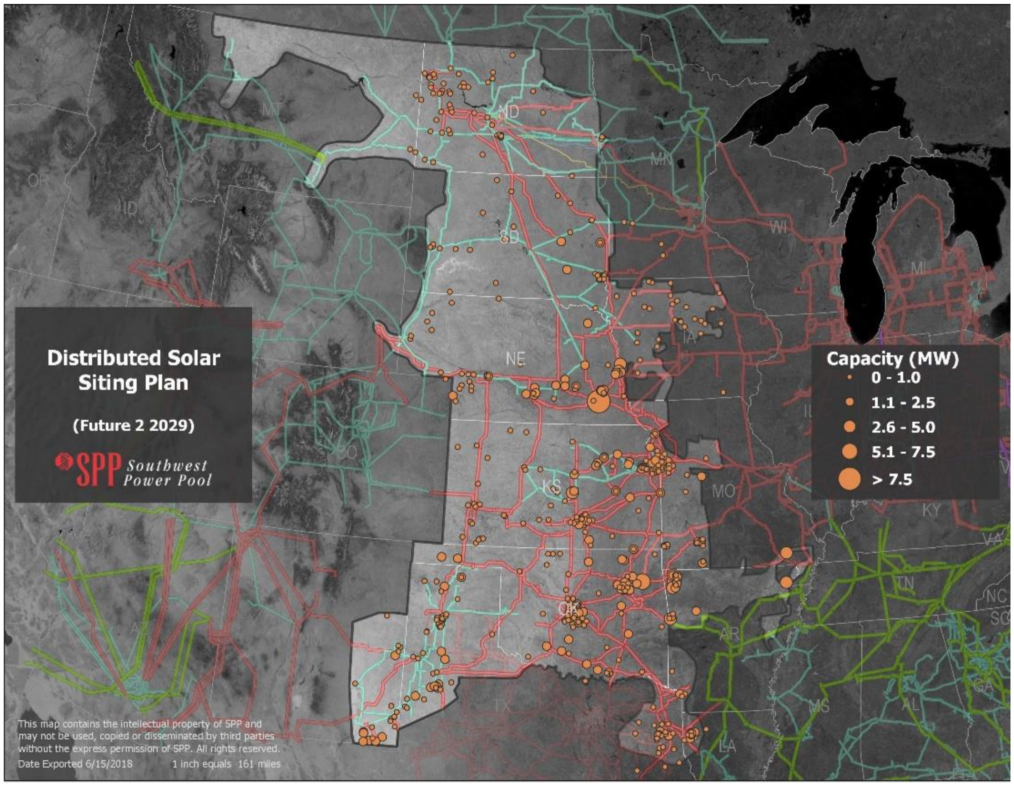


Figure 2.13: 2029 Future 2 Distributed Solar Siting Plan

Utility-scale solar was sited according to:

- Ownership by zone or by state.
- Data Source (given preference in the following order)
  - SPP and Integrated System (IS) and GI queue requests.
  - Stakeholder submitted sites.
  - Previous ITP sites.
  - Other National Renewable Energy Laboratory (NREL) conceptual sites.
- Capacity factor.
- Generator transfer capability of the potential sites.

Following the implementation of this ranking criteria, stakeholders could request exceptions to the results. The ESWG reviewed and approved the exceptions. Figure 2.14 through Figure 2.17 show the selected sited and allocation of utility solar capacity across the SPP footprint.

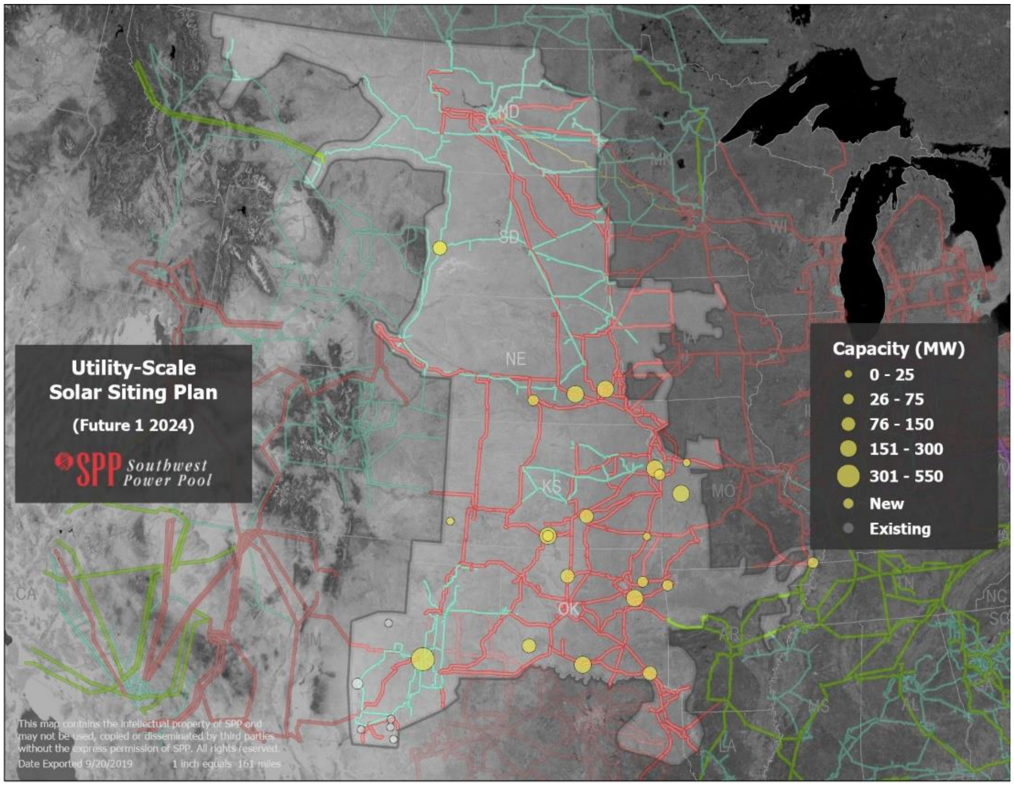


Figure 2.14: 2024 Future 1 Utility-Scale Solar Siting Plan

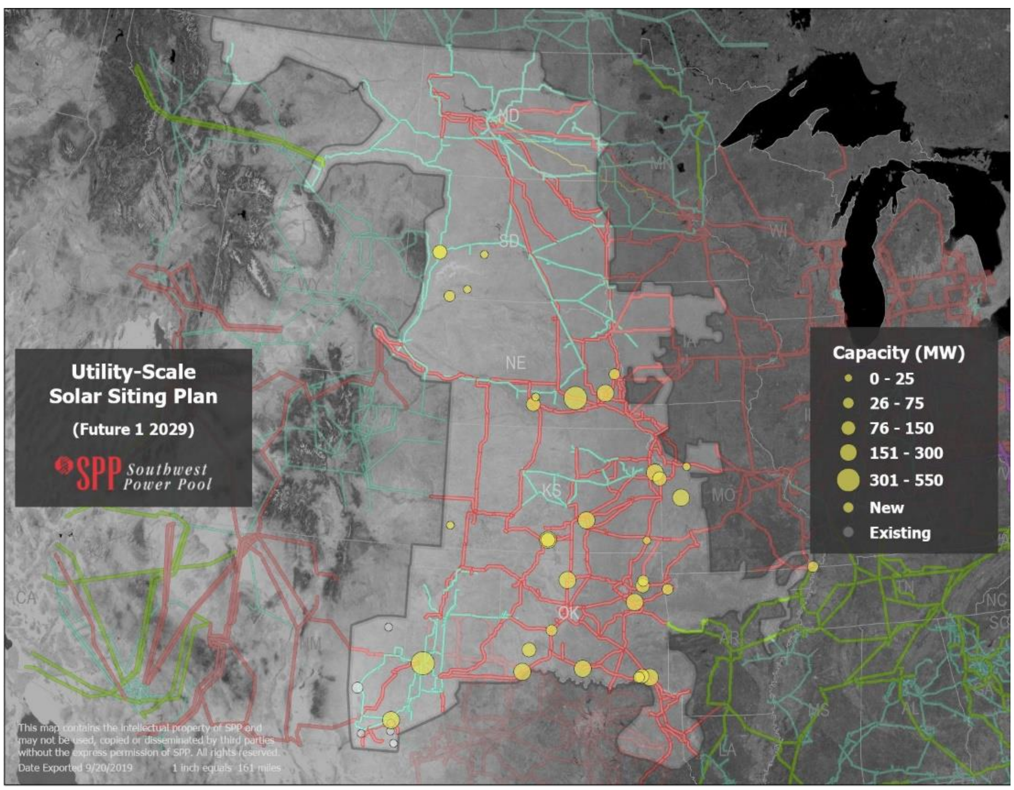


Figure 2.15: 2029 Future 1 Utility-Scale Solar Siting Plan

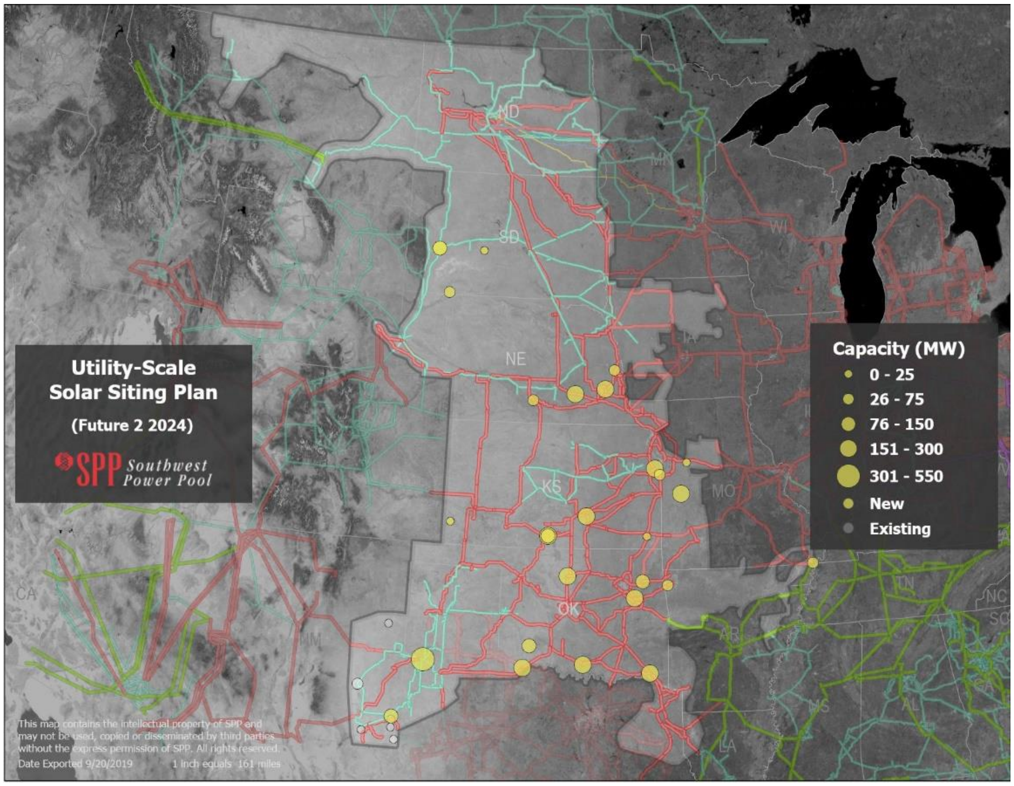


Figure 2.16: 2024 Future 2 Utility-Scale Solar Siting Plan

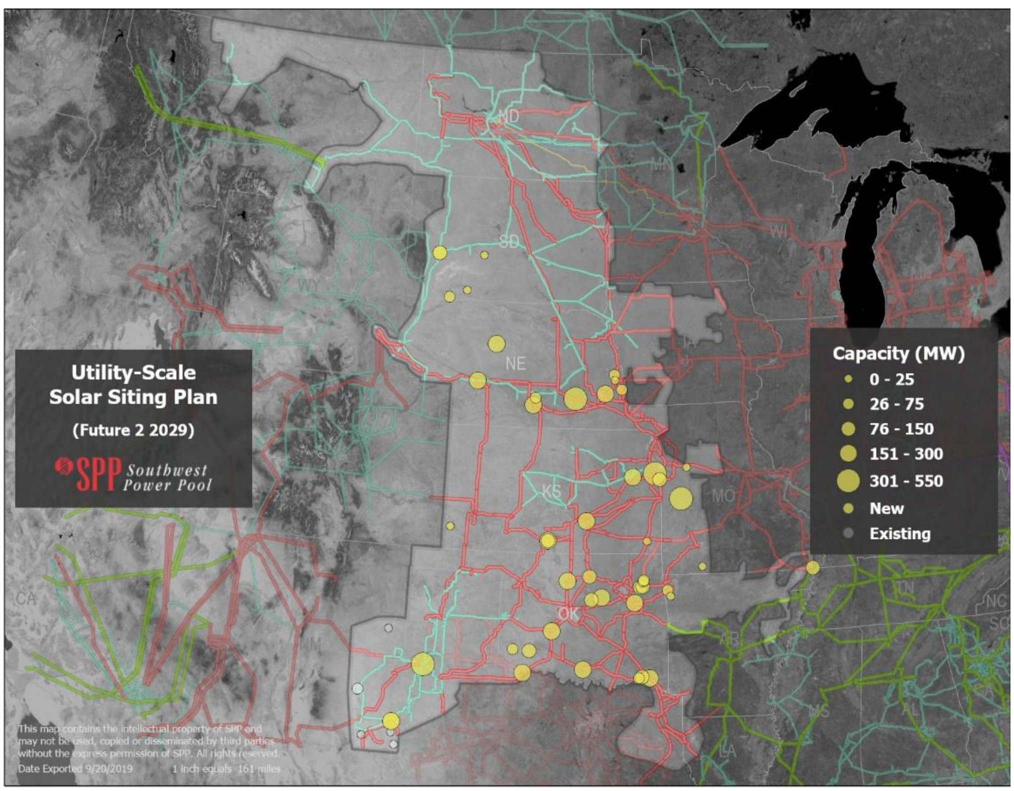


Figure 2.17: 2029 Future 2 Utility-Scale Solar Siting Plan

Wind sites were selected from GI queue requests that required the lowest total interconnection cost[10] per MW of capacity requested, taking into consideration the following:

- Potentially directly-assigned upgrade needed.
- Unknown third-party system impacts.
- Required generator outlet facilities (GOF).
- GI agreement (GIA) suspension status.

GI queue requests that did not have costs assigned were also considered with respect to their generator outlet capability, scope of related GOFs needed, and relation to recurring issues within the GI grouping.

Following implementation of this ranking criteria, stakeholders could request exceptions to these results. The ESWG reviewed and approved exception requests. Figure 2.18 through Figure 2.21 show the selected siting and allocation of wind capacity across the SPP footprint.

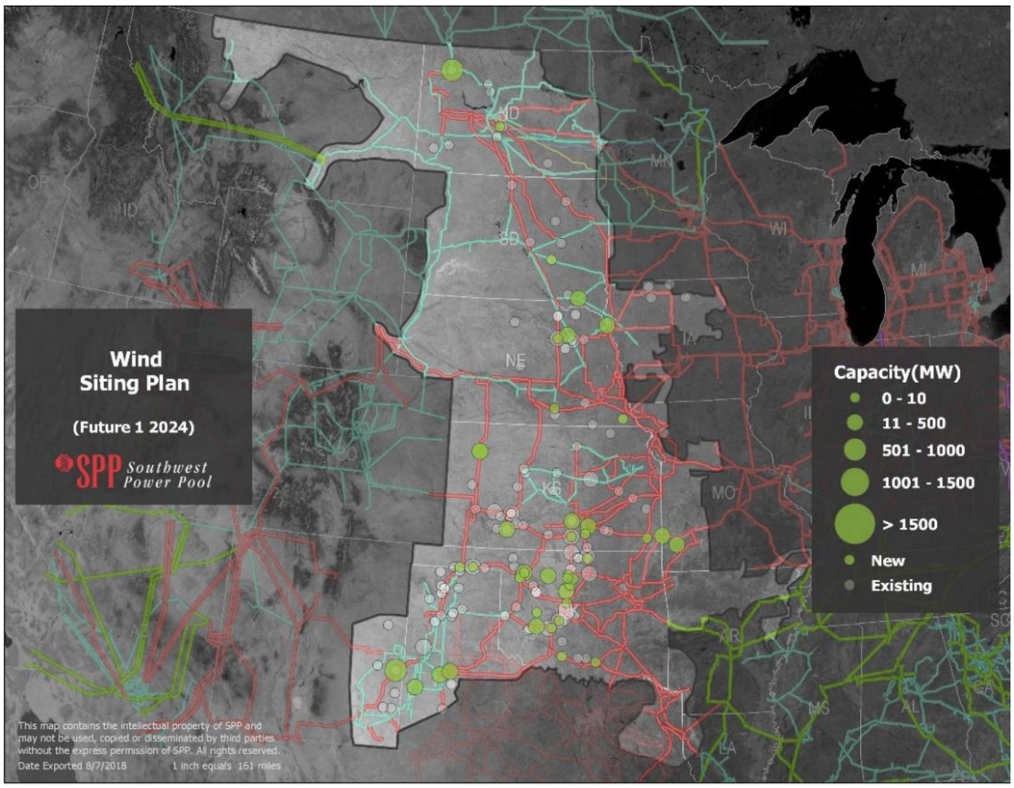


Figure 2.18: 2024 Future 1 Wind Siting Plan

[10] Includes assigned interconnection and network upgrade costs

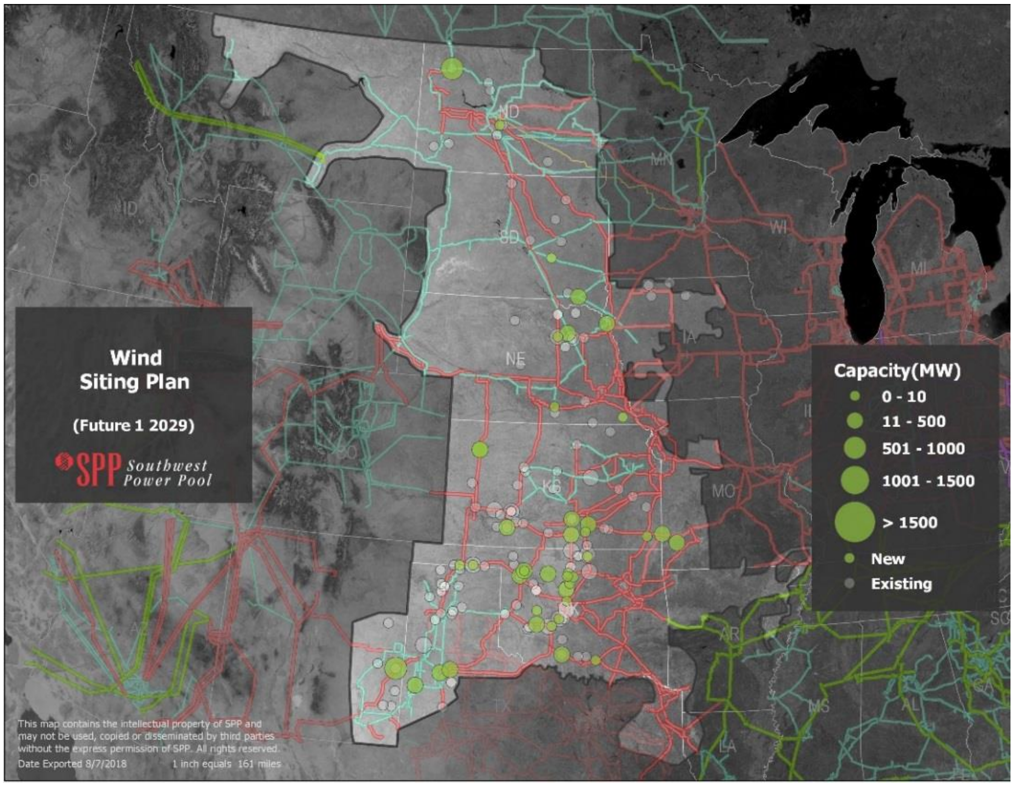


Figure 2.19: 2029 Future 1 Wind Siting Plan

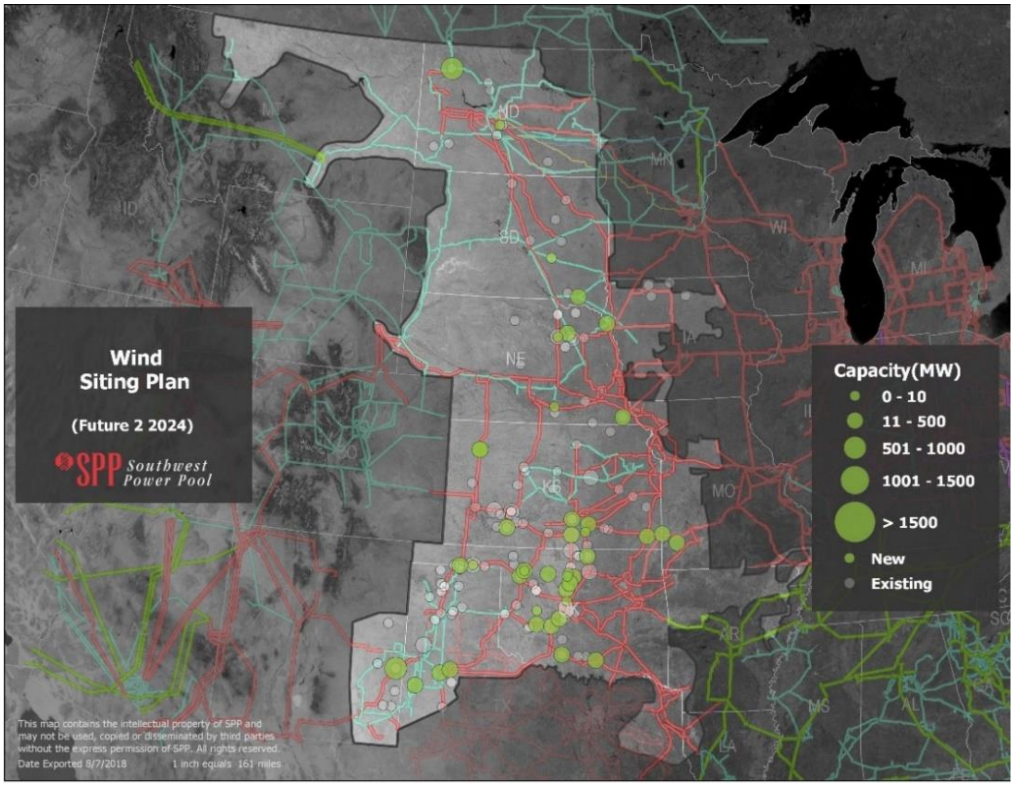


Figure 2.20: 2024 Future 2 Wind Siting Plan

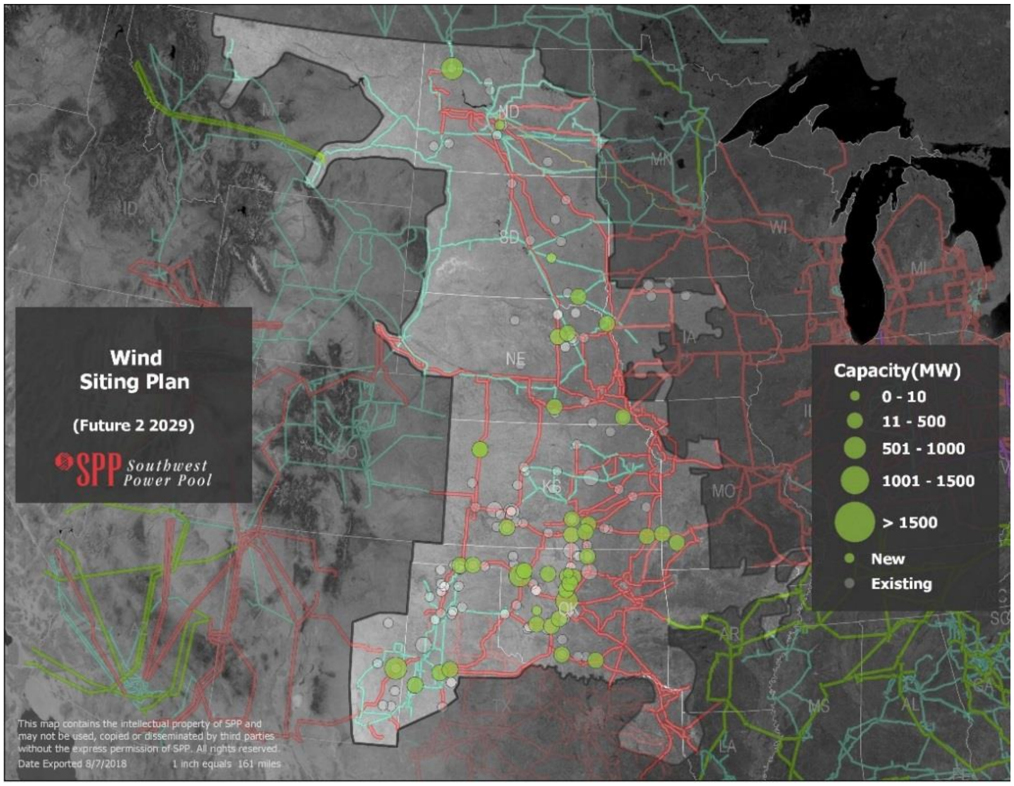


Figure 2.21: 2029 Future 2 Wind Siting Plan

Conventional generation was sited according to the zone of majority ownership, stakeholder preferences, generator outlet capability, scope of GOFs needed, and preference for existing and assumed retirement sites over previous ITP sites. Total conventional capacity at a given site (including existing) was limited to 1,500 MW. Following implementation of this ranking criteria, stakeholders could request exceptions to these results. The ESWG reviewed and approved exception requests. Figure 2.22 through Figure 2.25 show the selected sites for conventional generation across the SPP footprint.

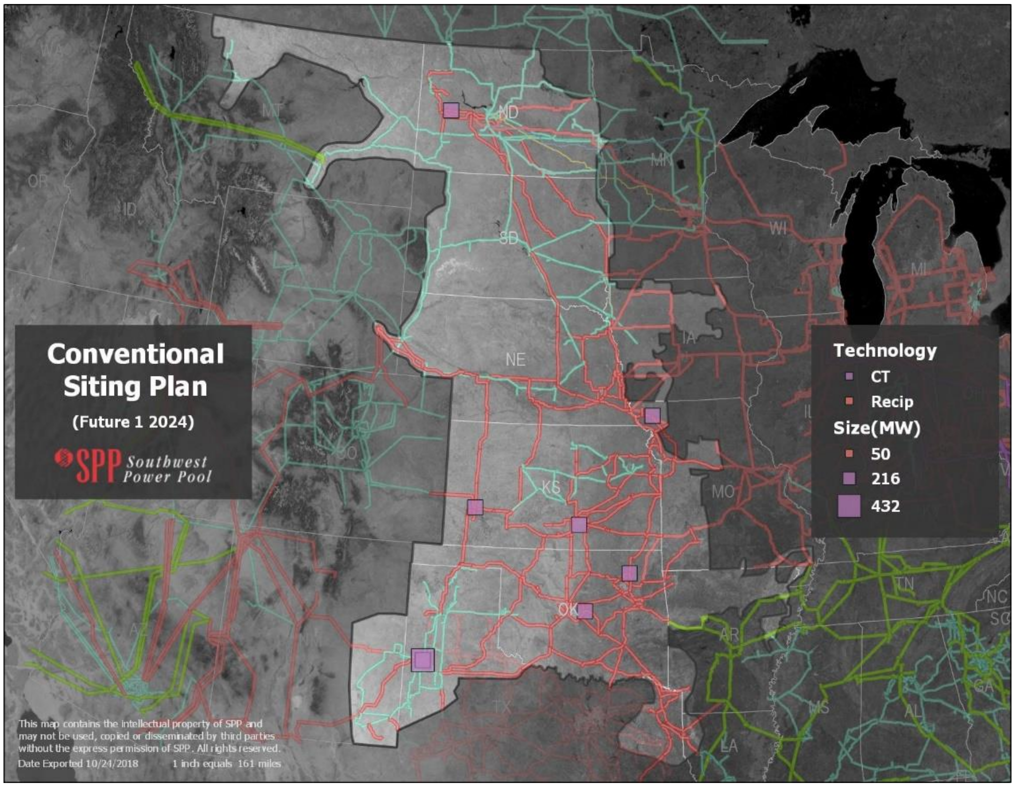


Figure 2.22: 2024 Future 1 Conventional Siting Plan

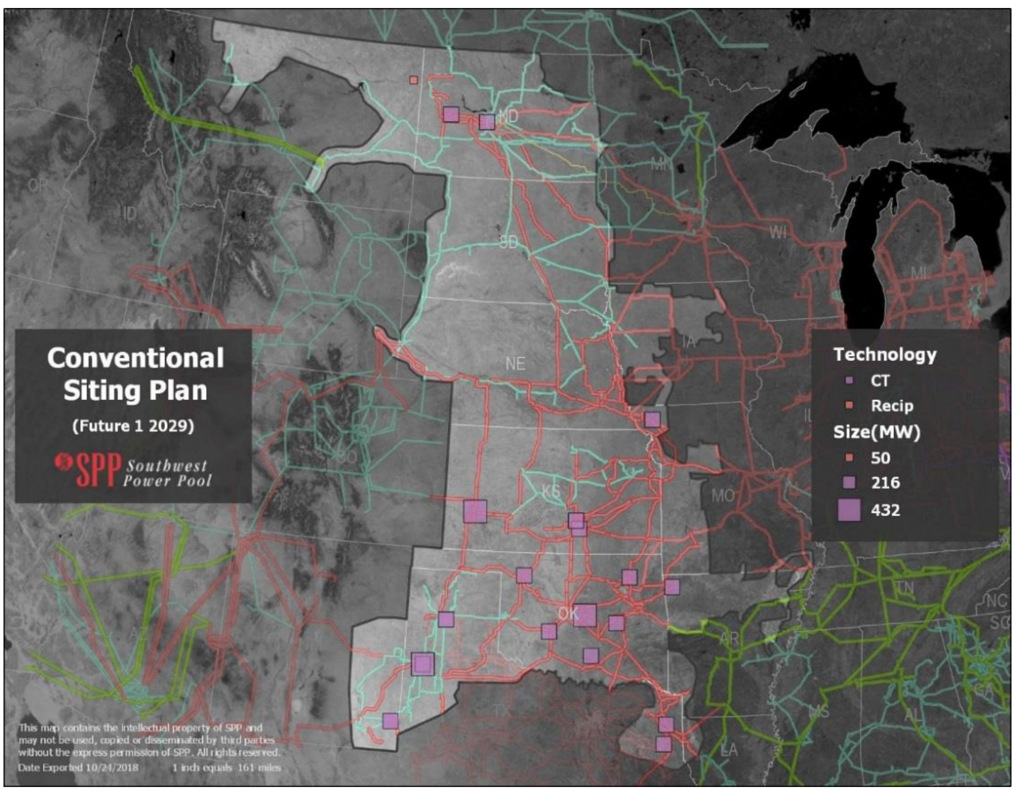


Figure 2.23: 2029 Future 1 Conventional Siting Plan

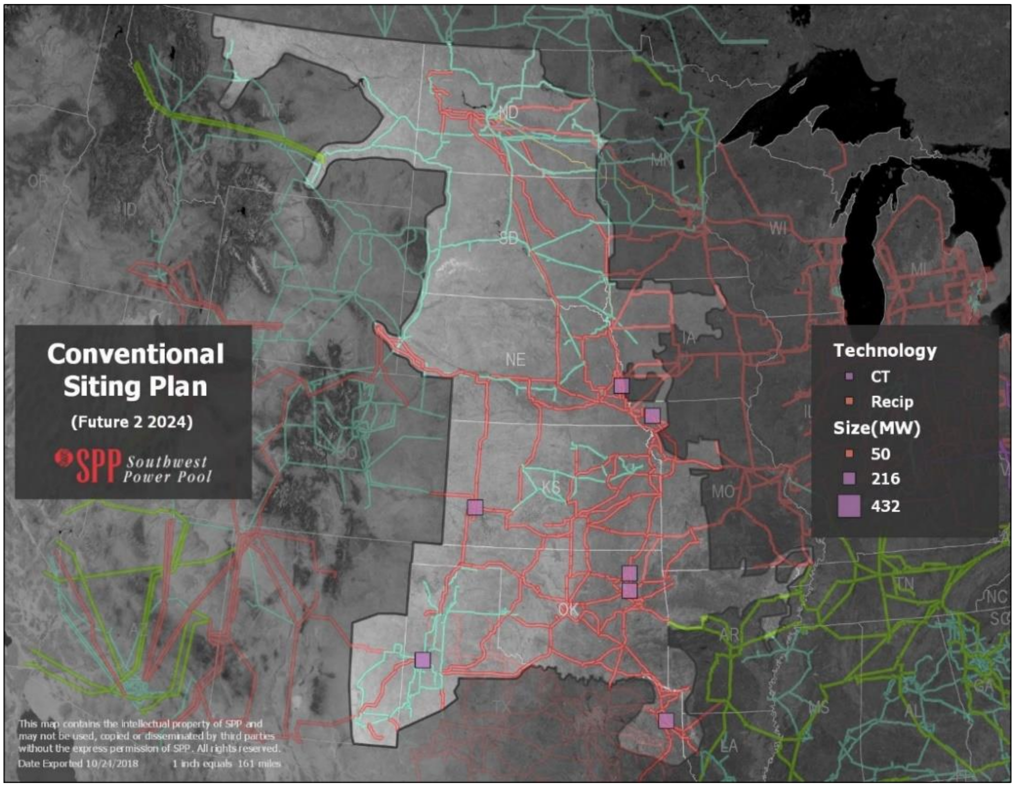


Figure 2.24: 2024 Future 2 Conventional Siting Plan

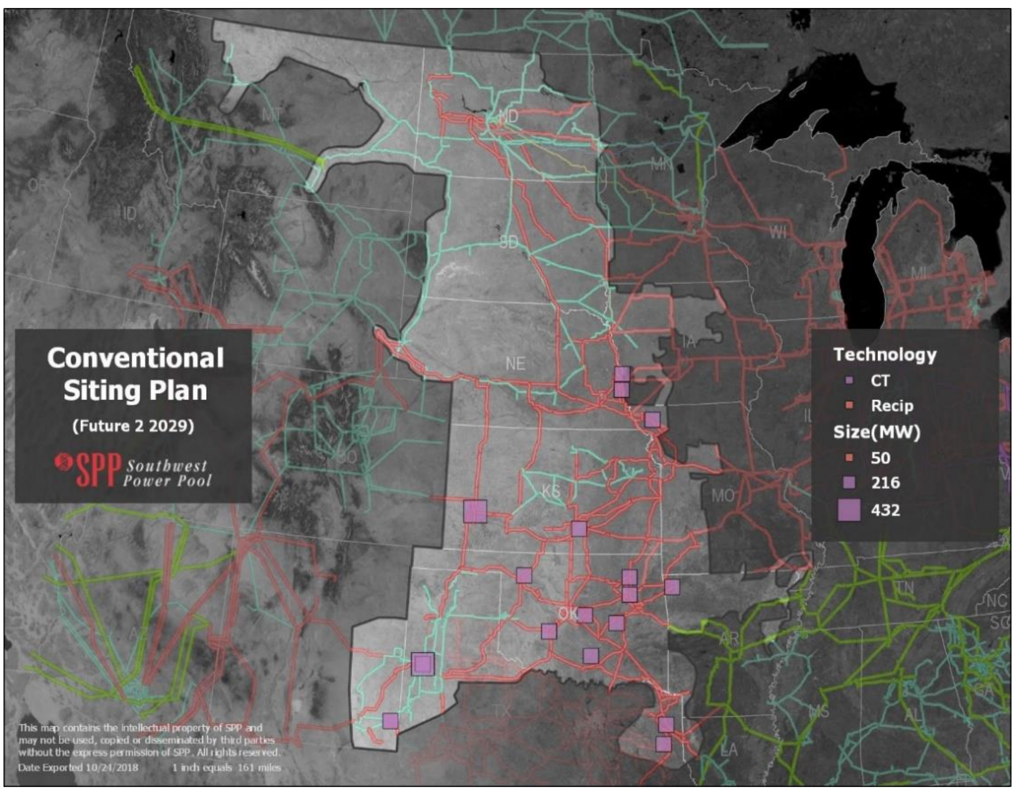


Figure 2.25: 2029 Future 2 Conventional Siting Plan

2.2.2.4 Generator Outlet Facilities (GOF)

The GOFs necessary to interconnect resources at individual sites were critical to the siting of resources. For sites with an executed GIA identifying a necessary upgrade, the upgrade included in the GIA was included as a GOF. For other instances, the site-specific results of a transfer analysis[11] conducted on all potential sites were assessed to determine if a site was capable of reliably allowing a resource to dispatch to the SPP system. The results of the GOF analysis determined the upgrades shown in Table 2.4.

GOF Description	Site	MW Sited	GOF Source
Second Tande-Neset 230 kV line New Neset 230/115 kV transformer	Tande 345 kV	604	Siting Availability
Cleo Corner-Cleo Tap 138 kV line terminal equipment	Cleo Corner 138 kV	200	GI Queue
Carl Junction-Asbury Plant-Purcell 161 kV line terminal equipment	Asbury Plant 161 kV	250	Siting Availability
Carthage SW-Carthage-La Russell-Monett 161 kV line terminal equipment	La Russell Energy Center 161 kV	250	Siting Availability
Second Tolk 345/230 kV transformer	Crossroads 345 kV	522	GI Queue
Eddy County-Crossroads 345 kV line terminal equipment Eddy County-Tolk 345 kV line terminal equipment	Crossroads 345 kV	522	Siting Availability

Table 2.4: GOFs

2.2.2.5 External Regions

When developing renewable resource plans, SPP did not directly consider renewable policy requirements for external regions. However, the Midcontinent Independent System Operator (MISO) and Tennessee Valley Authority (TVA) renewable resource expansion and siting plans were based on the 2018 MISO Transmission Expansion Planning (MTEP18) continued fleet change (CFC) and distributed and emerging technologies (DET) futures. Associated Electric Cooperative Inc. (AECI) renewable resource expansion plans were based on the SPP resource plan assumptions and feedback from the ESWG and AECI.

Conventional resource plans were incorporated for external regions included in the market simulations. Each region was surveyed for load and generation and assessed to determine the capacity shortfall. The MISO and TVA resource expansion and siting plans were based on the MTEP18 CFC and DET futures, while AECI resource expansion and siting plans were based on the SPP resource plan assumptions and feedback from the ESWG and AECI. Figure 2.26 and Figure 2.27 show the cumulative capacity additions by unit type of these external regions for Futures 1 and 2.

[11] First-contingency incremental transfer capability (FCITC) analysis

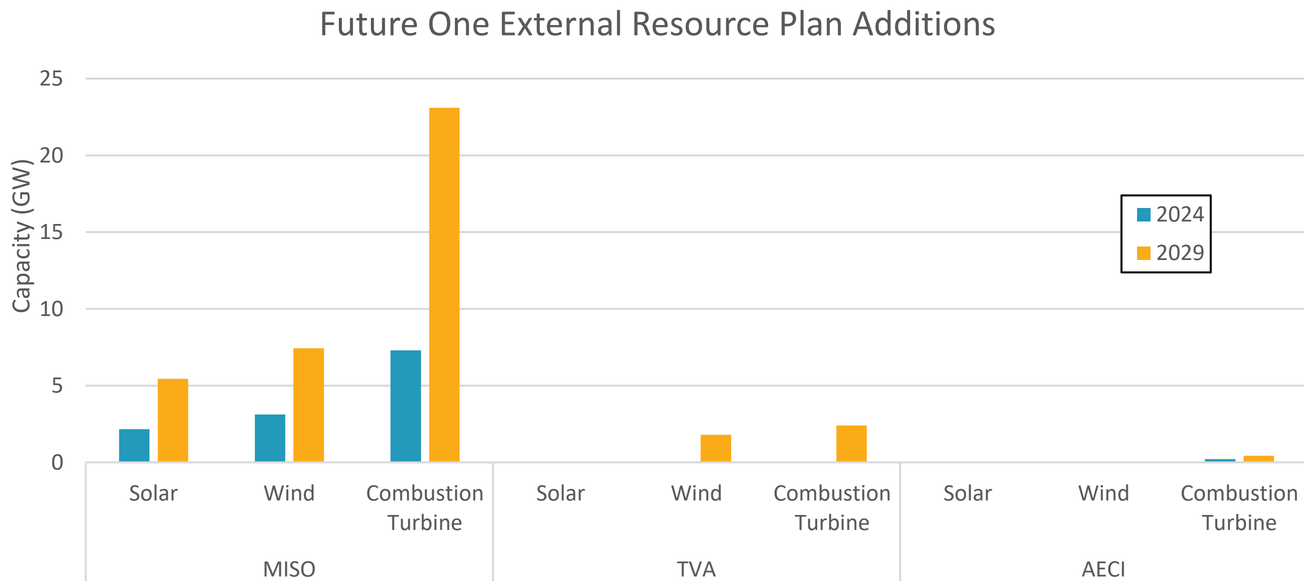


Figure 2.26: Capacity Additions by Unit Type – Future 1

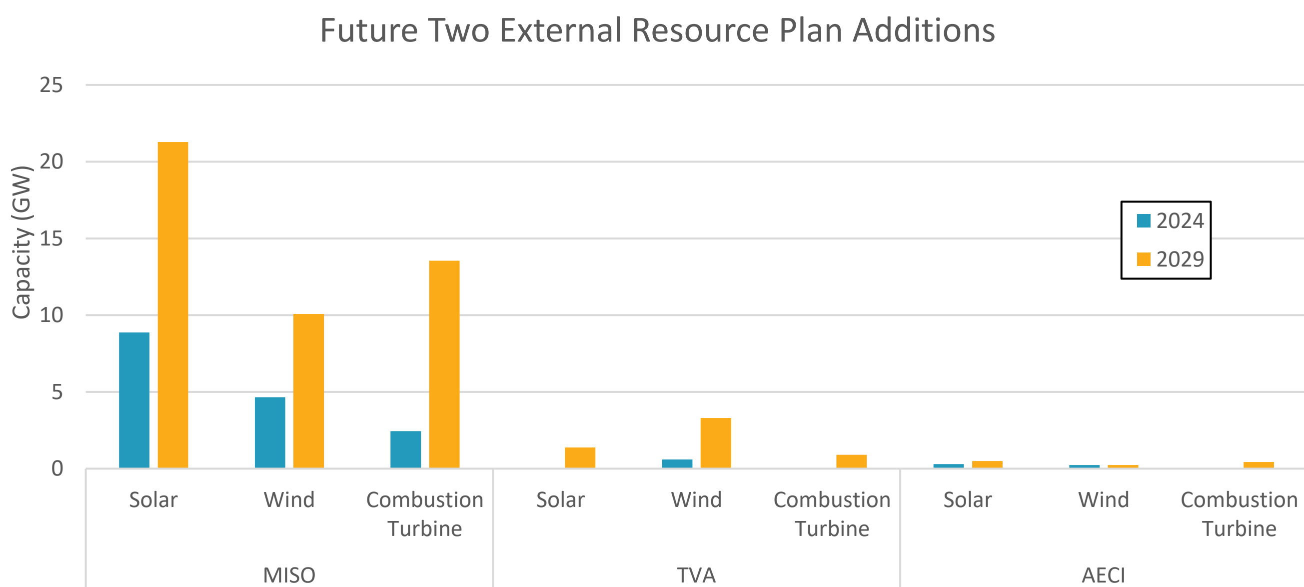


Figure 2.27: Capacity Additions by Unit Type – Future 2

2.2.3 CONSTRAINT ASSESSMENT

SPP considers transmission constraints when reliably managing, in the least-costly manner, the flow of energy across physical bottlenecks on the transmission system. Developing these study-specific constraints plays a critical part in determining transmission needs, as the constraint assessment identifies future bottlenecks and fine-tunes the market economic models.

SPP conducted an assessment to develop the list of transmission constraints used in the security-constrained unit commitment (SCUC) and security-constrained economic dispatch (SCED) analysis for all futures and study years. The TWG reviewed and approved elements identified in this assessment as limiting the incremental transfer of power throughout the transmission system, both under system intact and contingency situations. SPP staff defined the initial list of constraints leveraging the SPP permanent flowgate list[12], which consists of NERC-defined flowgates that are impactful to modeled regions and recent temporary flowgates identified by SPP in real-time.

MTEP18 constraints were used to help evaluate and validate constraints identified within MISO and other neighboring areas. Constraints identified in neighboring areas were considered for inclusion as a part of the ITP study constraint list.

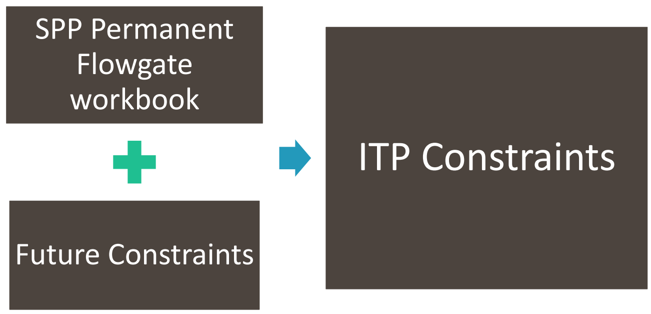


Figure 2.28: Constraint Assessment Process

2.3 MARKET POWERFLOW MODEL

The economic dispatch from each market economic model is used to develop market powerflow model snapshots representing stressed conditions on the SPP transmission system. Table 2.5 shows the SPP coincident peak (peak) and highest wind-to-load ratio (off-peak) reliability hours from each future and year of the market economic model simulations chosen for the market powerflow models.

	Off-Peak Hour	Wind Penetration[13]	Peak Hour	SPP Load (MW)
Future 1 2021	April 4 at 4:00 AM	79.5%	August 3 at 5:00 PM	52,958
Future 1 2024	April 1 at 3:00 AM	100.9%	July 30 at 4:00 PM	52,642
Future 1 2029	April 1 at 4:00 AM	100.9%	August 1 at 4:00 PM	54,470
Future 2 2024	April 1 at 3:00 AM	111.3%	July 16 at 4:00 PM	52,882
Future 2 2029	April 1at 4:00 AM	122.2%	July 17 at 4:00 PM	54,844

Table 2.5: Market Powerflow Reliability Hours

[12] Posted on SPP OASIS
[13] Does not include curtailments

3 BENCHMARKING

3.1 POWERFLOW MODEL

Powerflow model benchmarking for this assessment was performed on models from the 2018 ITP near-term (ITPNT) and 2019 ITP assessments. Model comparisons were conducted to ensure the accuracy of the powerflow model results, including:

- Comparison of the summer and winter year two load totals between the 2018 ITPNT scenario zero models and the 2019 ITP base reliability models. See Figure 3.1 and Figure 3.2.
- Comparison of the summer and winter years two, five, and 10 generation dispatch totals between the 2018 ITPNT scenario zero and base reliability models (summer only), and the 2019 ITP base reliability models. See Figure 3.3 and Figure 3.4.
- The summer and winter year 10 generator removals in the 2019 ITP base reliability models. See Figure 3.5.

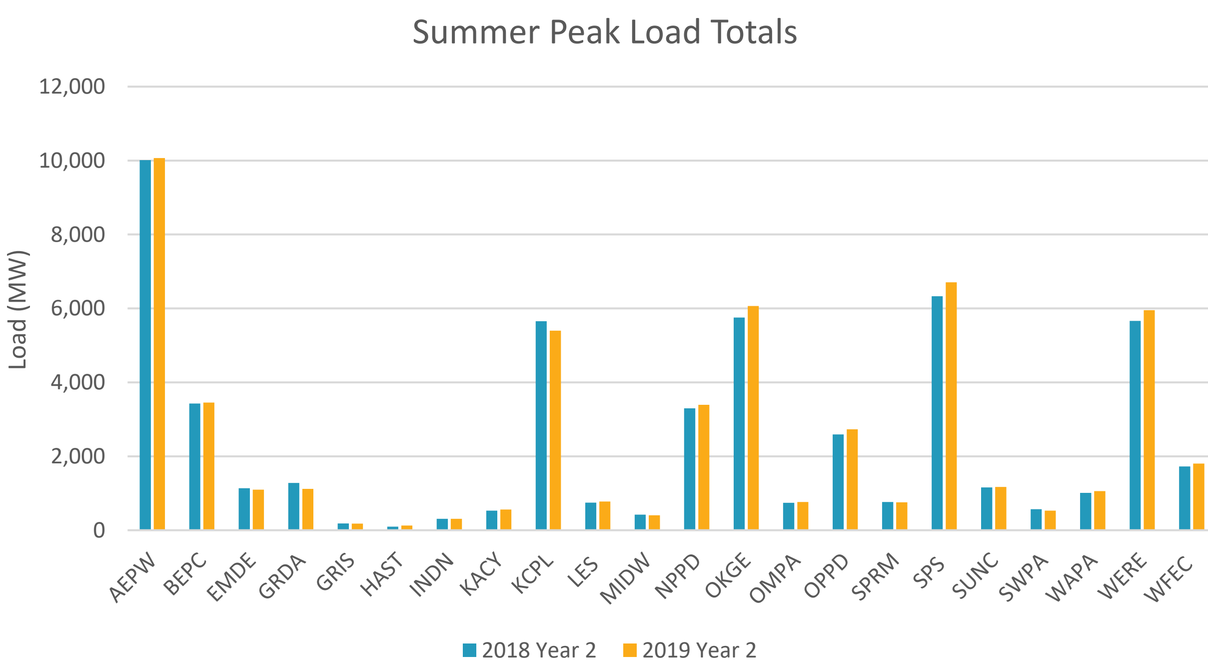


Figure 3.1: Summer Peak Year Two Load Totals Comparison

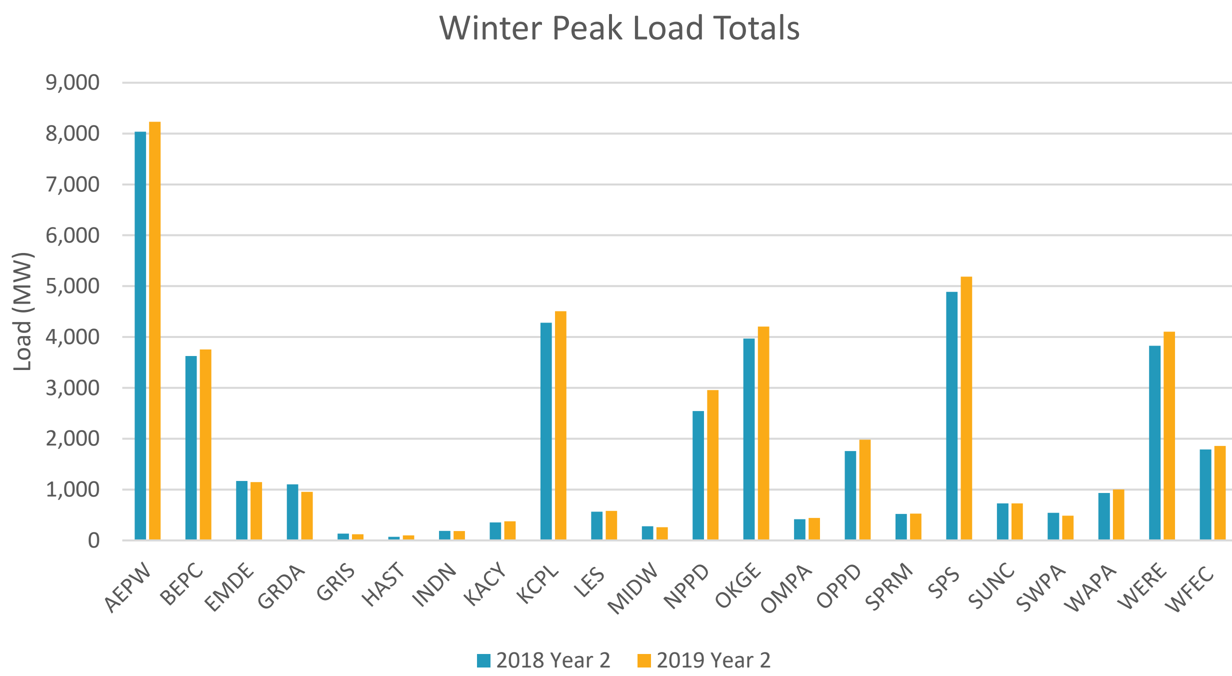


Figure 3.2: Winter Peak Year 2 Load Totals Comparison

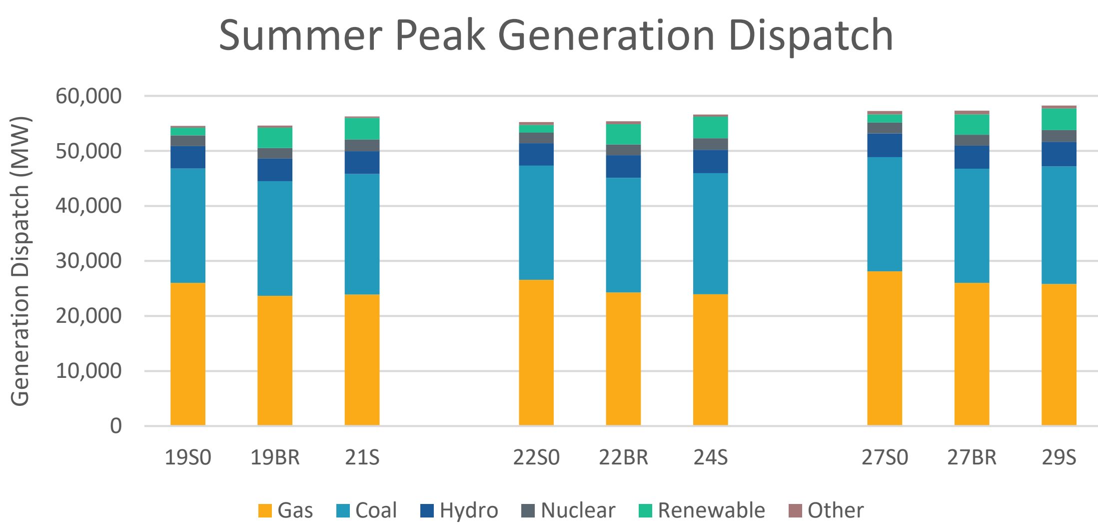


Figure 3.3: Summer Peak Years 2, 5, and 10 Generation Dispatch Comparison

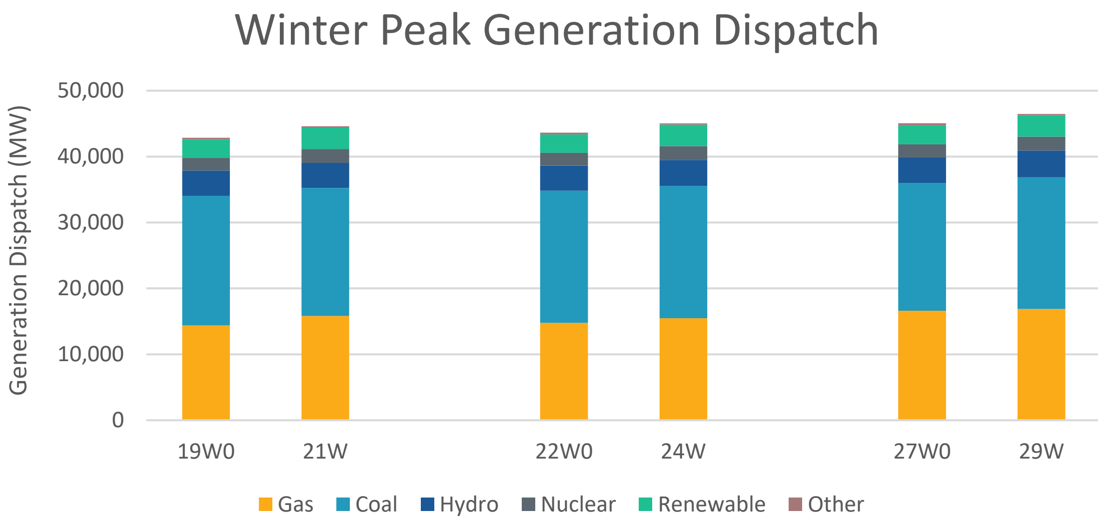


Figure 3.4: Winter Peak Years 2, 5, and 10 Generation Dispatch Comparison

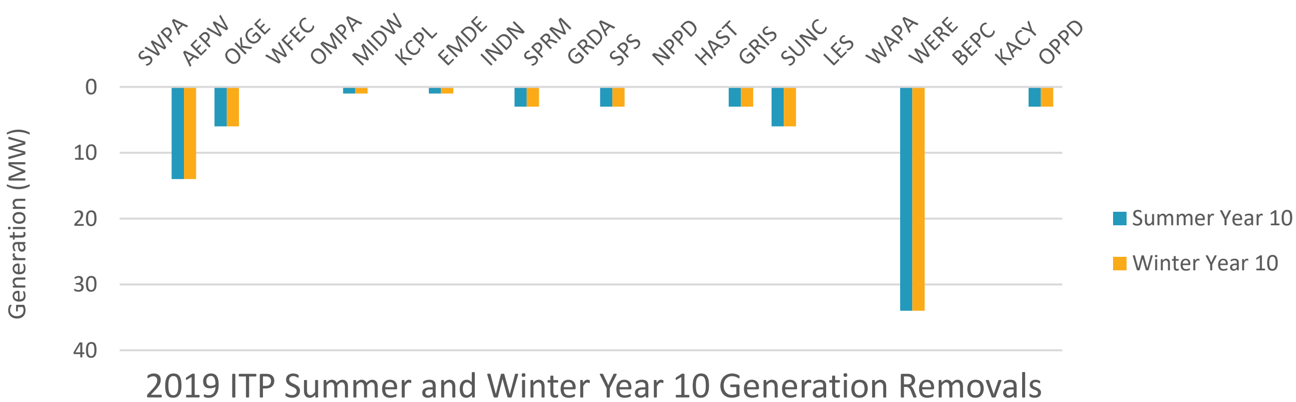


Figure 3.5: 2019 ITP Summer and Winter Year 10 Generation Removals

Operational model benchmarking for this assessment was performed on the year one model from the 2019 ITP base reliability models and August 2019 state estimator operational model (actual data). Model comparisons were conducted to ensure the accuracy of the powerflow model results, including:

- Comparison of the summer and winter load totals between the August 2019 state estimator operational model and 2019 ITP base reliability summer and winter year one model, as shown in Figure 3.6
- Comparison of the summer and winter generation dispatch totals between the August 2019 state estimator operational model and 2019 ITP base reliability summer and winter year one model, as shown in Figure 3.7 and Figure 3.8

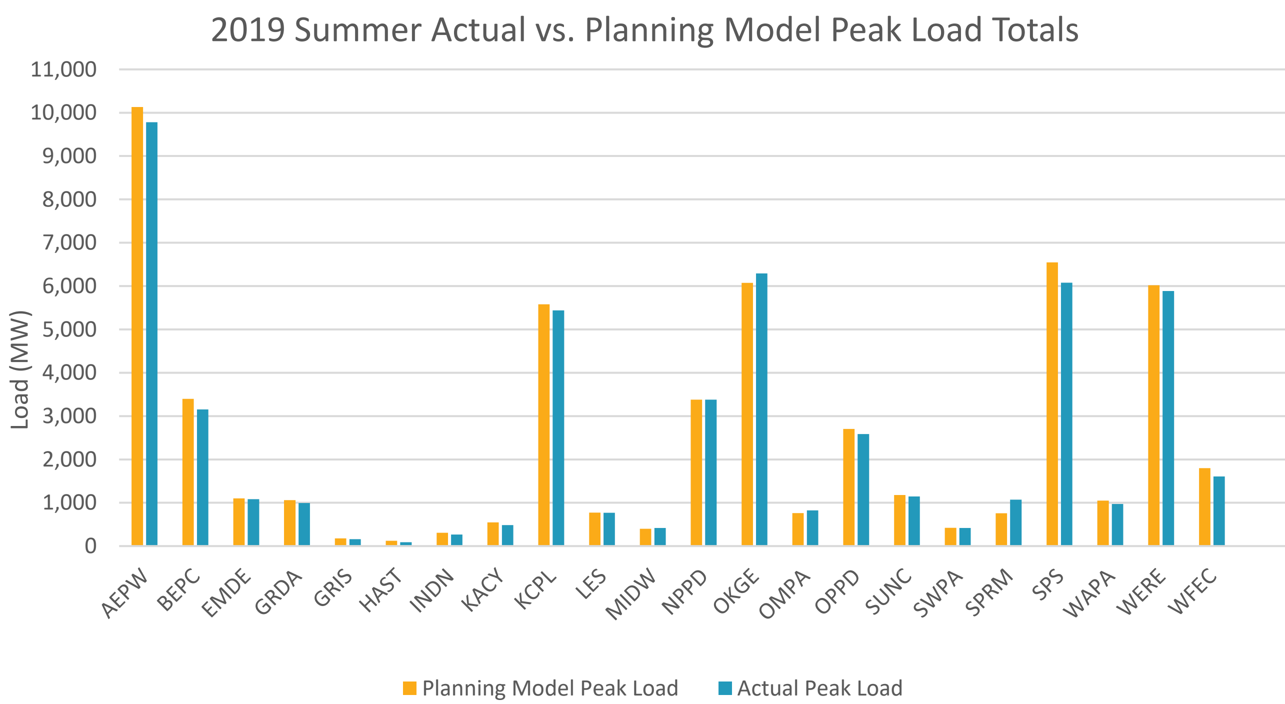


Figure 3.6: 2019 Summer Actual vs. Planning Model Peak Load Totals

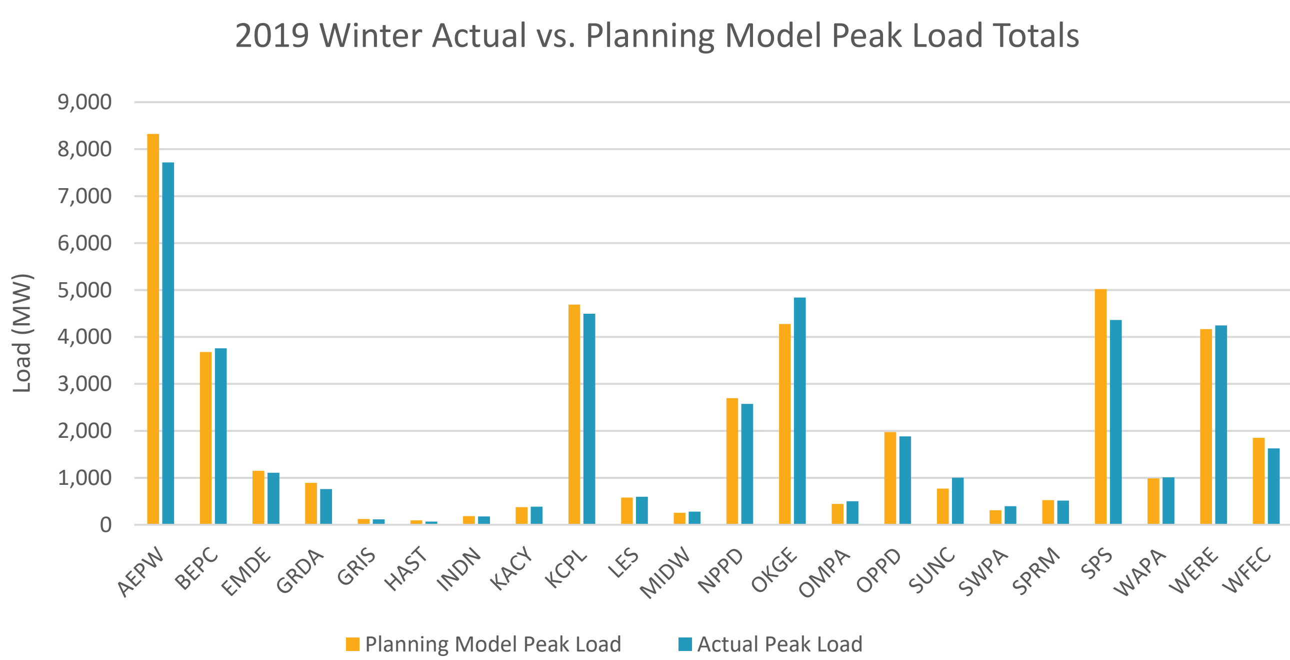


Figure 3.7: 2019 Winter Actual vs. Planning Model Peak Load Totals

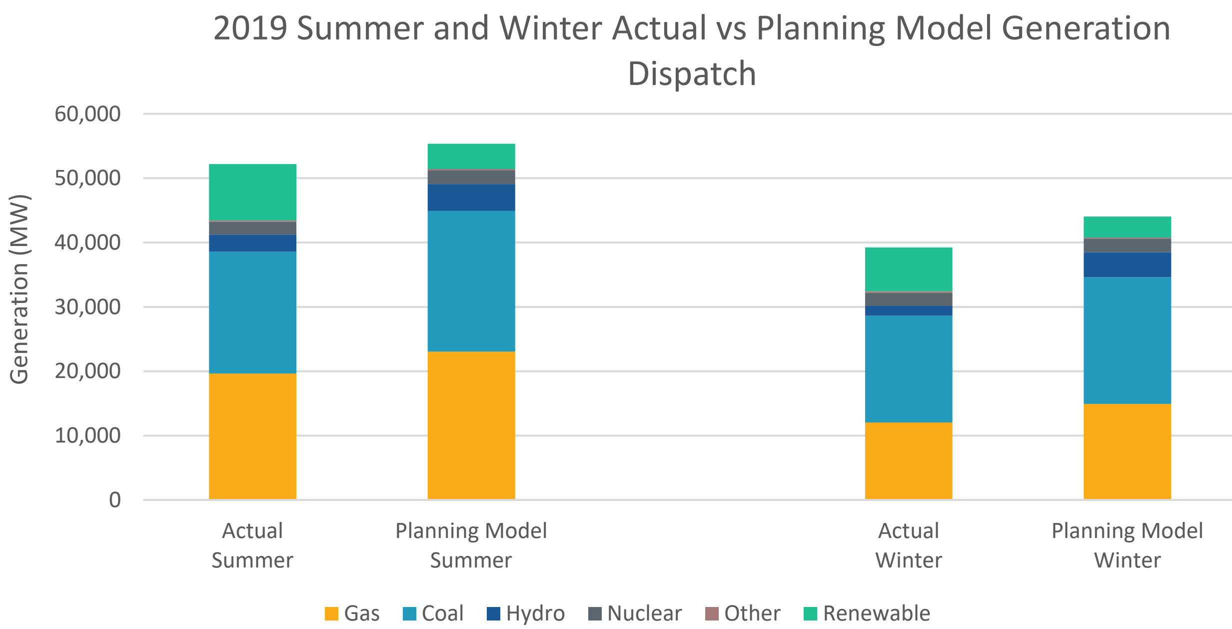


Figure 3.8: 2019 Actual vs. Planning Model Generation Dispatch Comparison

3.2 MARKET ECONOMIC MODEL

Market economic model benchmarking for this study was performed on the Year 2021 Future 1 market economic model. For the benchmarking process to provide the most value, it was important to compare the current study model against previous ITP modeling outputs and historical SPP real-time data. Numerous benchmarks were conducted to ensure the accuracy of the market economic modeling data, including:

- Comparing the 2019 ITP generation capacity factors with the U.S. Energy Information Administration (EIA) data, simulated maintenance outages to SPP real-time data, and operating and spinning reserve capacities to SPP Criteria; and
- Comparing the capacity factors, generating unit average cost, renewable generation profiles, system LMPs, APC, and interchange between the 2019 ITP and the 2017 ITP 10-year assessment (ITP10)[14].

3.2.1 GENERATOR OPERATIONS

3.2.1.1 Capacity Factor by Unit Type

Comparing capacity factors is a method for measuring the similarity in planning simulations and historical operations. This benchmark provides a quality control check of differences in modeled outages and assumptions regarding renewable, intermittent resources.

When compared with capacity factors reported to the EIA for 2014 and 2016 and resulting from the 2017 ITP10 study, the capacity factors for conventional generation units fell near the expected values. The

[14] The 2019 ITP Future 1 (reference case) and 2021 market economic model outputs were compared to the 2017 ITP10, Future 3 (reference case), 2020 market economic model outputs.

difference in capacity factors between the datasets is attributed to the fuel and load forecasts and the difference in generation mix.

	Average Capacity Factor			
Unit Type	**2014 EIA**	**2016 EIA**	**2017 ITP10 Future 3 2020**	**2019 ITP Future 1 2021**
Nuclear	92%	92%	89%	93%
Combined Cycle	50%	55%	32%	41%
CT Gas	5%	8%	3%	3%
Coal	60%	53%	78%	61%
ST Gas	10%	12%	2%	3%
Wind	34%	35%	46%	46%
Solar	26%	25%	20%	23%

Table 3.1: Generation Capacity Factor Comparison

3.2.1.2 Average Energy Cost

Examining the average cost per MWh by unit type gives insight into what units will be dispatched first (without considering transmission constraints). Overall, the average cost per MWh is lower in the 2019 ITP than in the 2017 ITP10 due to the fuel and load forecasts and the difference in generation mix.

	Average Energy Cost ($/MWh)	
Unit Type	**2017 ITP10 Future 3 2020**	**2019 ITP Future 1 2021**
Nuclear	$15	$15
Combined Cycle	$48	$31
CT Gas	$76	$44
Coal	$27	$24
ST Gas	$72	$41

Table 3.2: Average Energy Cost Comparison

3.2.1.3 Generator Maintenance Outages

Generator maintenance outages in the simulations were compared to SPP real-time data. These outages have a direct impact on flowgate congestion, system flows and the economics of serving load.

The curves from the historical data and the market economic model simulations complemented each other very well in shape. Although the market economic model simulation outages do not have as high a magnitude as the historical outages provided by SPP operations, the outage rates in the 2019 ITP are very similar to previous ITP assessments. The operations data includes outage types, such as “economic outages” that are difficult to exclude from the dataset and cannot be replicated in these planning models. The difference in magnitude between the real-time data and the market economic simulated outages is due to the additional operational outages beyond those required by annual maintenance or driven by forced (unplanned) conditions.

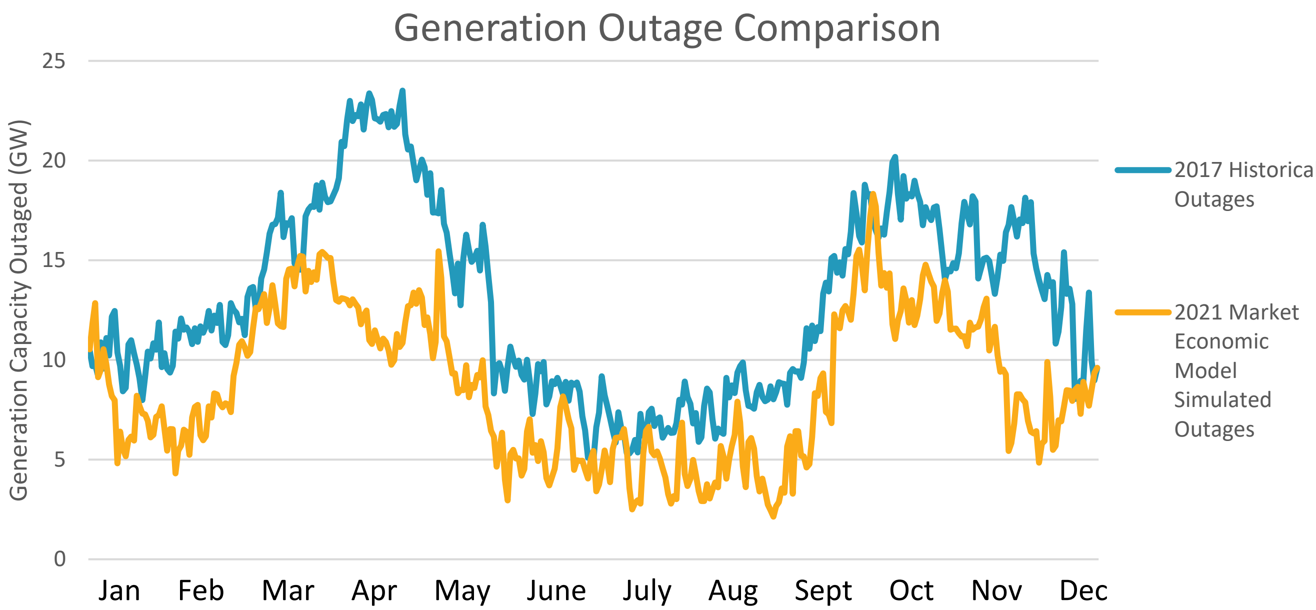


Figure 3.9: Generator Outage Comparison

3.2.1.4 Operating and Spinning Reserve Adequacy

Operational reserve is an important reliability requirement that is modeled to account for capacity that might be needed in the event of unplanned unit outages. According to SPP Criteria, operating reserves should meet a capacity requirement equal to the sum of the capacity of largest unit in SPP and half of the capacity of the next largest unit in SPP. At least half of this requirement must be fulfilled by spinning reserve.

The operating reserve capacity requirement was modeled at 1,646 MW and spinning reserve capacity requirement was modeled at 823 MW. SPP met its reserve requirements in the market economic model.

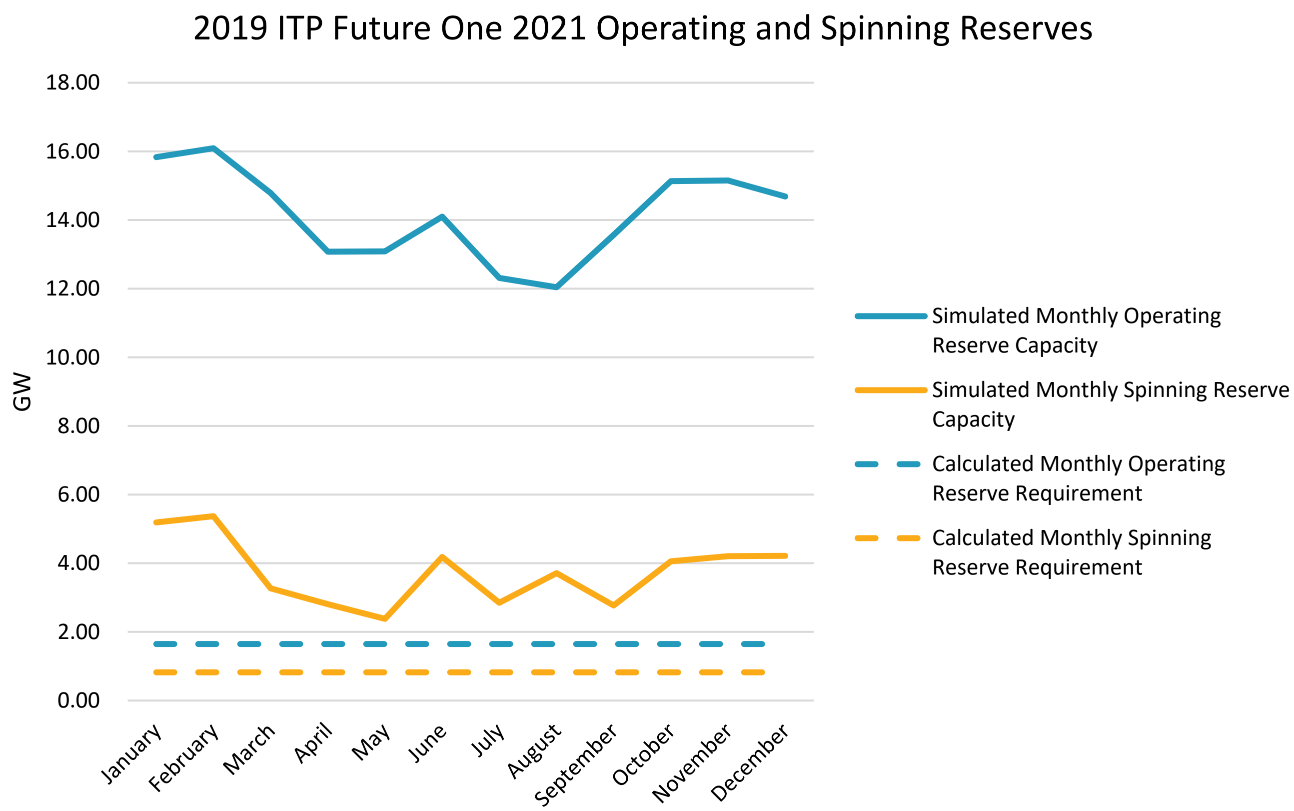


Figure 3.10: 2019 ITP Future 1 2021 Operating and Spinning Reserves

3.2.1.5 Renewable Generation

Wind energy output is overall greater in the 2019 ITP than the 2017 ITP10. In the 2017 ITP10, wind energy includes resource plan additions; however, a greater amount of wind is projected to be in-service by 2021 in the 2019 ITP model.

Solar energy is lower in the 2019 ITP than in the 2017 ITP10 because solar resource plan additions were modeled in the 2017 ITP10 model. The 2020 solar projection in the 2017 ITP10 is higher than solar in the 2019 ITP model for 2021. The solar energy for 2021 in the 2019 ITP model represents existing solar in the SPP footprint.

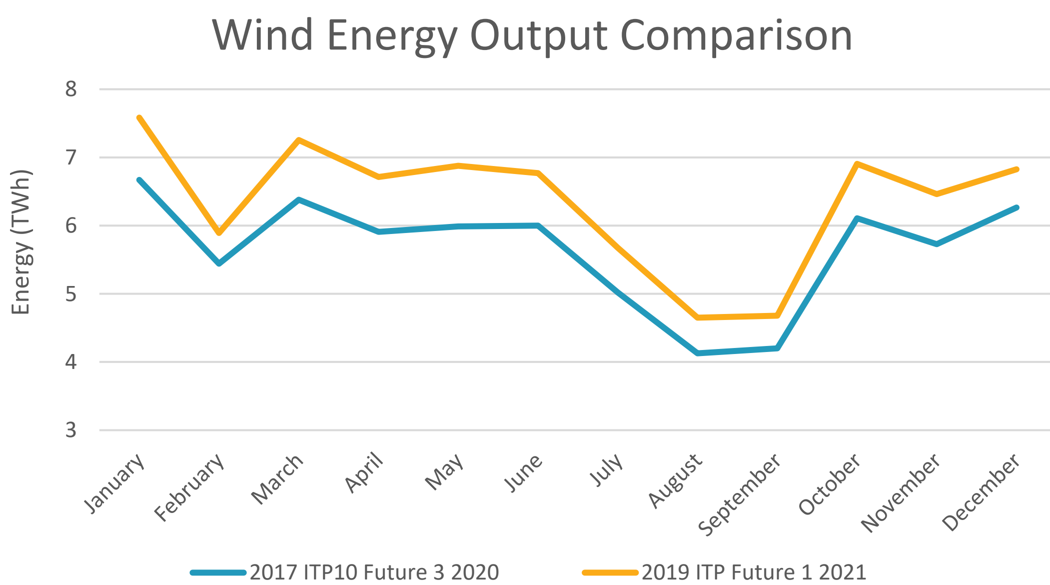


Figure 3.11: Wind Energy Output Comparison

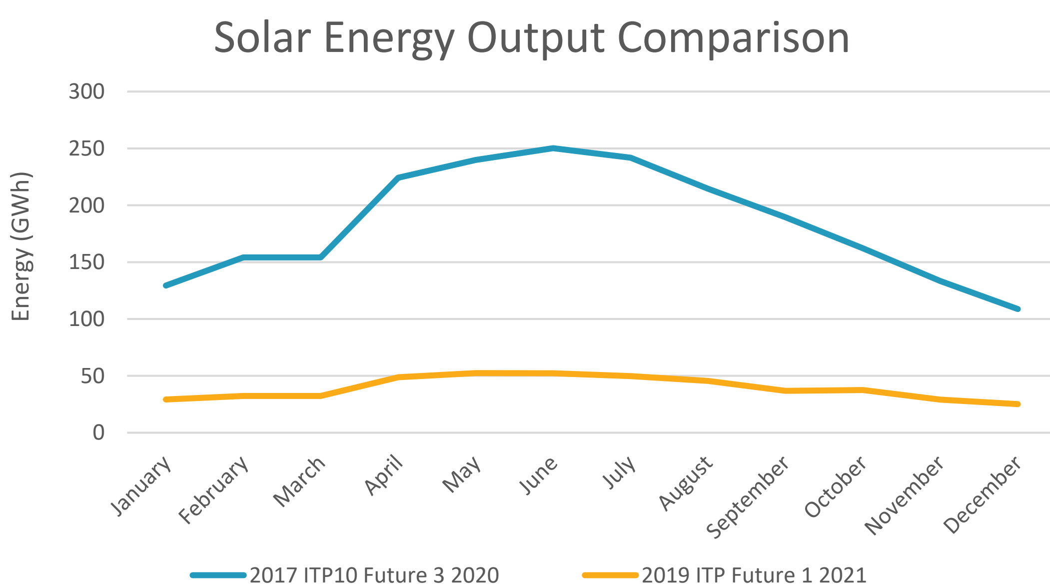


Figure 3.12: Solar Energy Output Comparison

When compared with capacity factors from the 2017 ITP10, the 2019 ITP capacity factors for renewable generation units fell near the expected values. The wind unit capacity factors in the 2017 ITP10 and 2019 ITP are very similar. The amount of wind energy is relatively similar between both models, and both models utilized the 2012 NREL dataset for hourly profile data. The solar capacity factors in the 2019 ITP are slightly higher than in the previous study due to utilizing the 2012 NREL dataset instead of the 2006 NREL dataset for hourly profile data.

	Average Capacity Factor			
Unit Type	2014 EIA	2016 EIA	2017 ITP10 Future 3 2020	2019 ITP Future 1 2021
Wind	34%	35%	46%	46%
Solar	26%	25%	20%	23%

Table 3.3: Renewable Generation Capacity Factor Comparison

3.2.2 SYSTEM LOCATIONAL MARGINAL PRICE (LMP)

Simulated LMPs were benchmarked against simulated LMPs from the 2017 ITP10. This data was compared on an average monthly value-by-area basis. Figure 3.13 portrays the results of the benchmarking model for the SPP system and the difference in the two curves. The decrease in LMPs since the 2017 ITP10 is due to the change in fuel and load forecasts between studies.

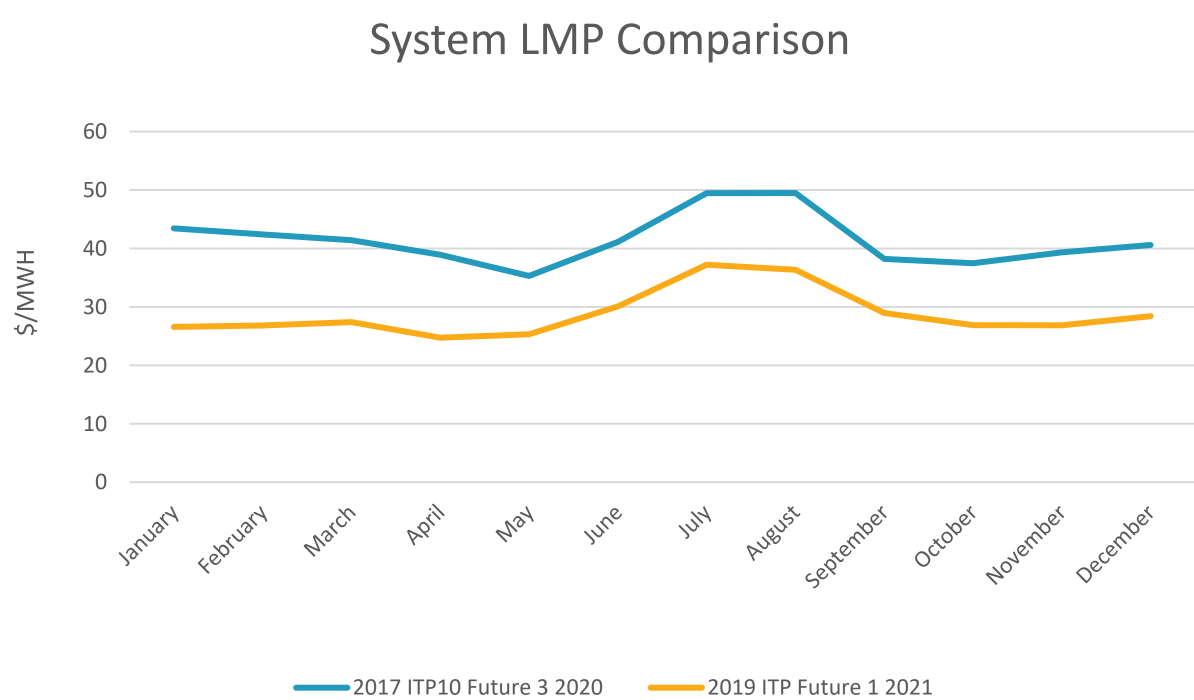


Figure 3.13: System LMP Comparison

3.2.3 ADJUSTED PRODUCTION COST (APC)

Examining the APC provides insight to which entities generally purchase generation to serve their load and which entities generally sell their excess generation. APC results for SPP zones were overall lower in the 2019 ITP than in the 2017 ITP10 due to the change in fuel and load forecasts.

The APC for all zones in SPP decreased except for the Nebraska Public Power District (NPPD) and the Omaha Public Power District (OPPD). These anomalies are attributed to the retirement of the Fort Calhoun nuclear unit since the 2017 ITP10 model build and the different ownership assignment of wind in the 2019

ITP. Overall, each modeled region's APC results decreased between the two models, as expected from the increase in renewable forecasts. See Figure 3.14 and Figure 3.15 for a summary of regional APC results.

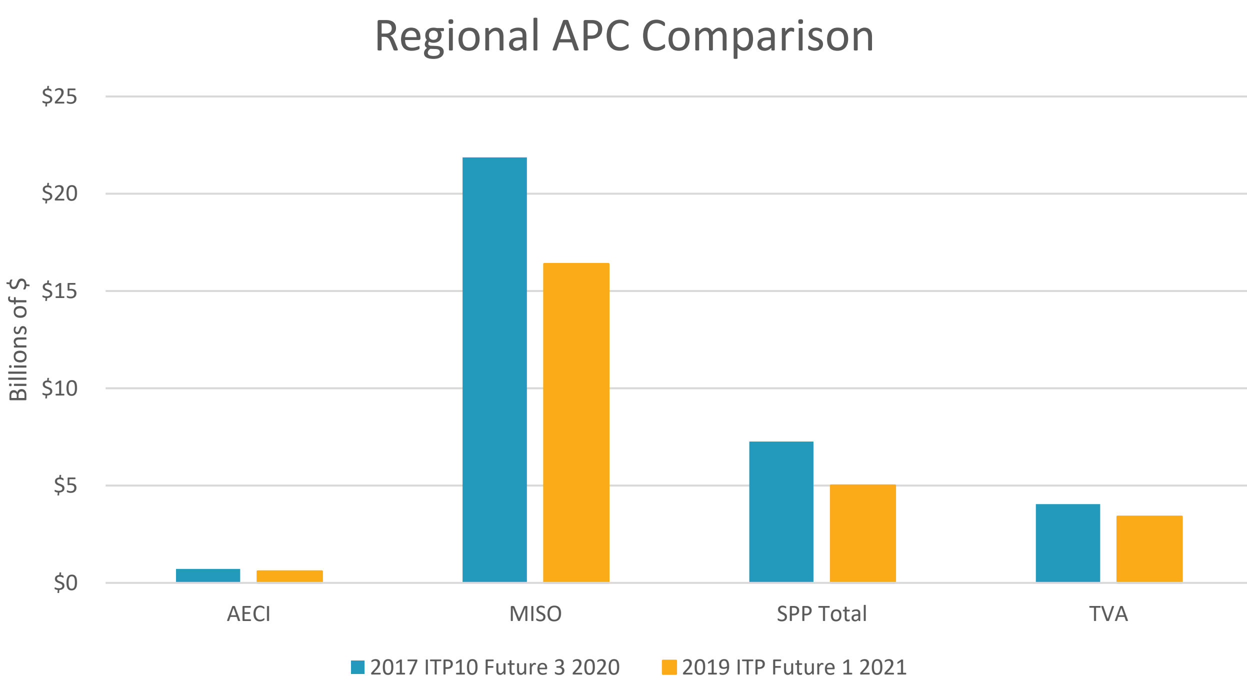


Figure 3.14: Regional APC Comparison

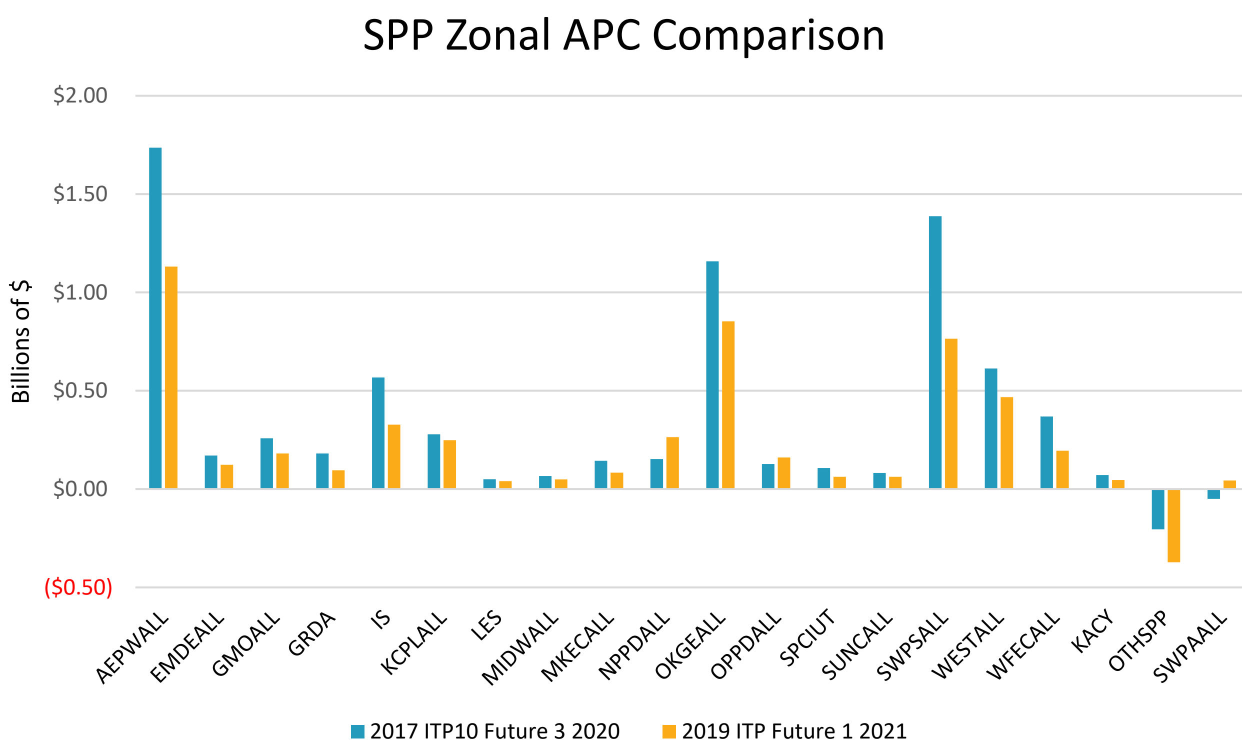


Figure 3.15: SPP Zonal APC Comparison

3.2.4 INTERCHANGE

Hurdle rate and interchange tests were implemented to validate the interchange in the 2019 ITP model. To test the behavior of both models with different hurdle rates, the previous study's hurdle rates were applied to the current study model and the current study hurdle rates were applied to the previous study model. The 2017 ITP10 hurdle rates increased overall exports in the 2019 ITP model. The 2019 ITP hurdle rates decreased overall exports in the 2017 ITP10 model. The 2019 ITP model interchange was validated against current SPP operations data. When compared to the SPP net scheduled interchange in 2017, the 2019 ITP model is similar in shape and magnitude. Overall, exports are lower in the 2019 ITP than in the 2017 ITP10.

Based on all interchange testing, the 2019 ITP model interchange is an acceptable representation of exports seen in the SPP Integrated Marketplace.

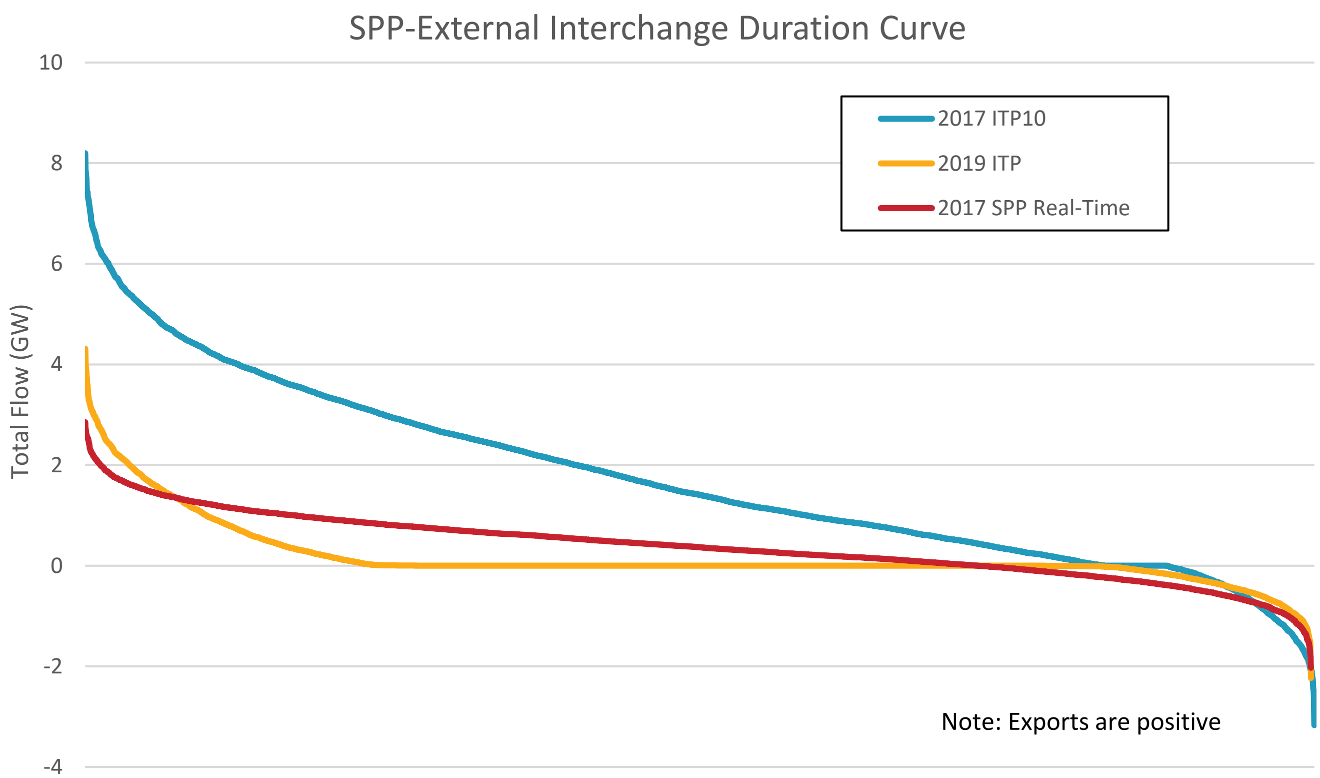


Figure 3.16: Interchange data comparison

4 NEEDS ASSESSMENT

4.1 ECONOMIC NEEDS

SPP determines its economic needs based on the congestion score associated with a constraint (monitored element/contingent element pair). The congestion score is calculated by multiplying the number of hours a constraint is congested in the model by the average shadow price of that constraint. Constraints with a calculated congestion score greater than 50k are considered an economic need. Additional constraints were identified that did not meet the 50k score because they were heavily related to a previous constraint. The economic needs identified per future are shown in Figure 4.1 and Figure 4.2, and Table 4.1 and Table 4.2.

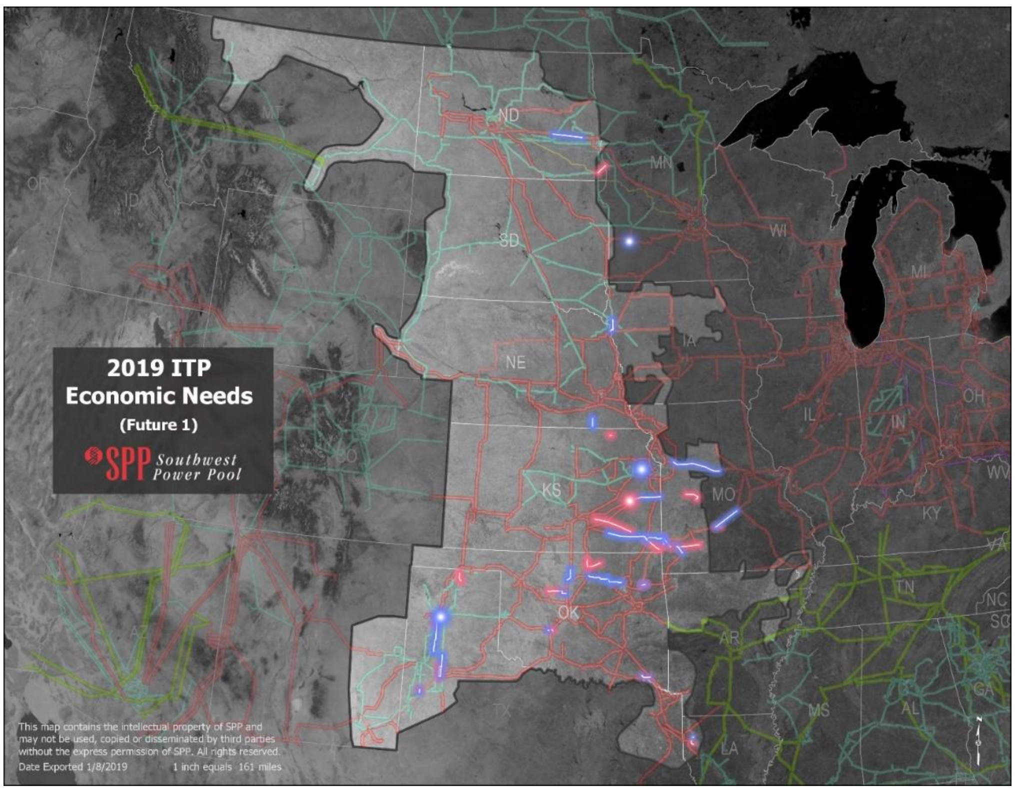


Figure 4.1: Future 1 Economic Needs

Rank	Constraint	2021 Congestion Score	2024 Congestion Score	2029 Congestion Score
1	Butler-Altoona 138 kV for the loss of Caney River-Neosho 345 kV	258,542	434,827	1,034,322
2	Cleveland AECI-Cleveland GRDA 138 kV for the loss of Cleveland-Tulsa North 345 kV	189,616	532,356	382,685
3	Lawrence Energy Center-Midland 115 kV for the loss of Lawrence Hill 230/115 kV transformer	95,537	195,517	384,195
4	Kerr-Maid 161 kV circuit 2 for the loss of Kerr-Maid 161 kV circuit 1	285,494	190,263	183,892
5	Clinton-Trumann 161 kV for the loss of Overton-Sibley 345 kV	0	151,398	212,899
6	Hankinson-Wahpeton 230 kV for the loss of Buffalo-Jamestown 345 kV	100	64,893	171,568
7	Hale County-Tuco 115 kV for the loss of Swisher-Tuco 230 kV	158,719	19,394	21,718
8	Kingfisher-East Kingfisher Tap 138 kV for the loss of Dover-Dover Switchyard 138 kV	0	86,104	113,196
9	South Shreveport-Wallace Lake 138 kV for the loss of Fort Humbug-Trichel Street 138 kV	0	3,157	187,532
10	Kildare-White Eagle 138 kV for the loss of Woodring-Hunter 345 kV	99,902	41,743	40,217
11	La Russell-Springfield 161 kV for the loss of La Russell-Monett 161 kV	7	53,855	118,064
12	Marshall County-Smittyville 115 kV for the loss of Harbine-Steele City 115 kV	90,957	39,535	36,040
13	Sundown-Amoco Tap 115 kV for the loss of Sundown-Amoco S.S. 230 kV	513	71,766	93,533
14	Dover-Okeene 138 kV for the loss of Watonga Switch-Okeene 138 kV	85,312	26,835	49,230
15	Gracemont-Anadarko 138 kV for the loss of Washita-Southwestern Station 138 kV	12,144	54,147	91,421
16	Spearman County-Hansford 115 kV for the loss of Potter County 345/230 kV transformer	49,403	42,800	59,943
17	Carthage SW-Purcell SW 161 kV for the loss of Ashbury-Carl Junction 161 kV	0	67,898	75,884
18	Potter County-Bushland 230 kV for the loss of Potter County-Newhart 230 kV	48,635	34,040	55,451
19	Asbury-Carl Junction 161 kV for the loss of Asbury-Purcell SW 161 kV	6,708	60,301	62,562

Rank	Constraint	2021 Congestion Score	2024 Congestion Score	2029 Congestion Score
20	Wolf Creek 345/69 kV transformer for the loss of Waverly-La Cygne 345 kV	19,451	50,981	49,484
21	Neosho-Riverton 161 kV for the loss of Blackberry/RP2POI02-Neosho 345 kV	49,364	40,233	29,788
22	Sioux City SC2-Sioux City 230 kV for the loss of Raun-Sioux City 345 kV	-	26,403	20,521
23	Coffman-Huben 161 kV for the loss of Franks-Huben 345 kV	-	13,830	9,257
24	Granite Falls-Marshall Tap 115 kV for the loss of Lyon Co 345/115 kV transformer	13,656	45,034	59,782
25	Webb City Tap-Osage 138 kV for the loss of Sooner-Cleveland 345 kV	4,407	41,416	54,125
27	Northwest-Matthewson 345 kV for the loss of Cimarron-Northwest 345 kV	6,176	9,687	77,171
28	Waverly-La Cygne 345 kV for the loss of Caney River-Neosho 345 kV	14,910	20,241	17,047

Table 4.1: Future 1 Economic Needs

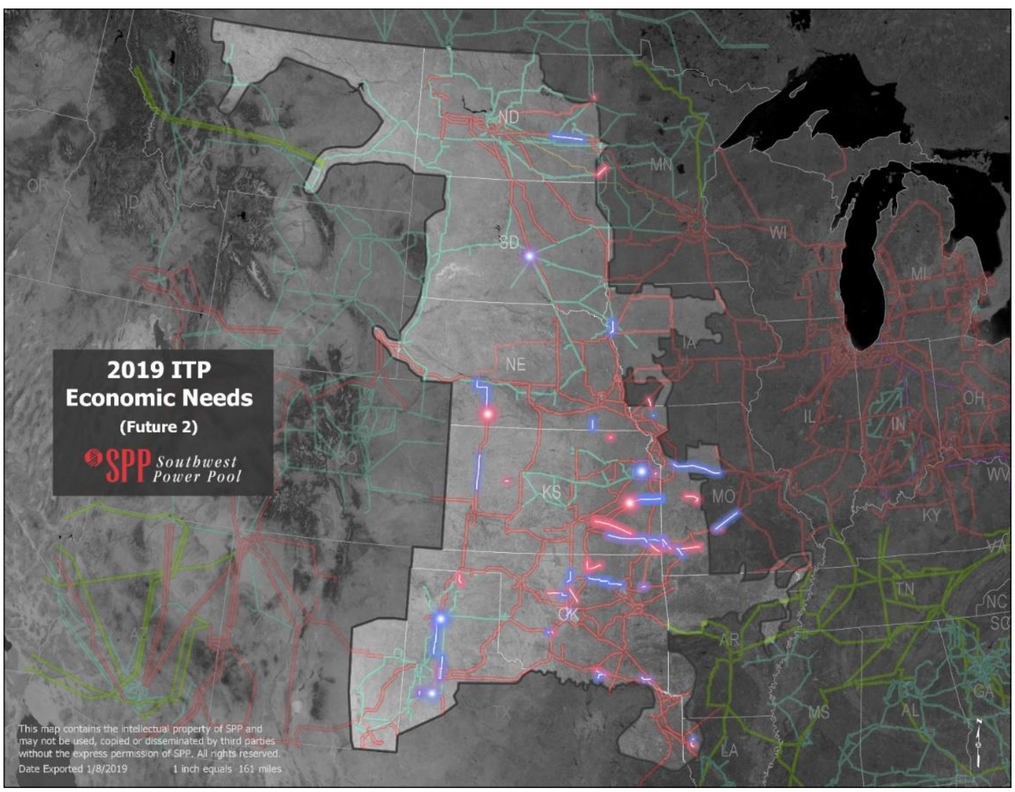


Figure 4.2: Future 2 Economic Needs

Rank	Constraint	2024 Congestion Score	2029 Congestion Score
1	Butler-Altoona 138 kV for the loss of Caney River-Neosho 345 kV	704,406	1,188,264
2	Cleveland AECI-Cleveland GRDA 138 kV for the loss of Cleveland-Tulsa North 345 kV	701,946	533,105
3	Lawrence Energy Center-Midland 115 kV for the loss of Lawrence Hill 230/115 kV transformer	234,634	622,429
4	Kerr-Maid 161 kV circuit 2 for the loss of Kerr-Maid 161 kV circuit 1	229,440	302,129
5	Hankinson-Wahpeton 230 kV for the loss of Buffalo-Jamestown 345 kV	92,405	419,129
6	South Brown-Russett 138 kV for the loss of Caney Creek-Little City 138 kV	157,255	349,052
7	Clinton-Trumann 161 kV for the loss of Overton-Sibley 345 kV	126,369	154,273
8	South Shreveport-Wallace Lake 138 kV for the loss of Fort Humbug-Trichel Street 138 kV	5,334	256,002
9	Sundown-Amoco Tap 115 kV for the loss of Sundown-Amoco S.S. 230 kV	114,173	136,720
10	La Russell-Springfield 161 kV for the loss of La Russell-Monett 161 kV	76,292	143,344
11	Kingfisher-East Kingfisher Tap 138 kV for the loss of Dover-Dover Switchyard 138 kV	136,687	77,642
12	Gracemont-Anadarko 138 kV for the loss of Washita-Southwestern Station 138 kV	87,638	125,272
13	Wolf Creek 345/69 kV transformer for the loss of Waverly-La Cygne 345 kV	84,733	101,602
14	Sioux City SC2-Sioux City 230 kV for the loss of Raun-Sioux City 345 kV	57,710	107,454
15	Spearman County-Hansford 115 kV for the loss of Potter County 345/230 kV transformer	97,186	67,820
16	Hugo-Valliant 138 kV for the loss of Valliant-Hugo 345 kV	40,891	94,244
17	Neosho-RP2POI10 345 kV for the loss of Waverly-La Cygne 345 kV	46,601	71,507
17	Neosho-Riverton 161 kV for the loss of Blackberry/RP2OI02-Neosho 345 kV	43,235	43,677
18	Cottonwood Creek-RP2POI11 138 kV system intact	0	115,784
19	Coffman-Huben 161 kV for the loss of Franks-Huben 345 kV	66,999	47,148
20	Red Willow 345/115 kV transformer for the loss of Gerald Gentleman-Red Willow 345 kV	60,143	53,895

Rank	Constraint	2024 Congestion Score	2029 Congestion Score
21	Grand Forks-Falconer 115 kV for the loss of Drayton-Prairie 230 kV	7,259	105,277
22	Carthage SW-Purcell SW 161 kV for the loss of Ashbury-Carl Junction 161 kV	52,511	56,931
23	Arnold-Ransom 115 kV for the loss of Mingo-Setab 345 kV	43,993	59,143
24	Ft. Thompson 345/230 kV transformer #2 for the loss of Ft. Thompson 345/230 kV transformer #1	20,415	82,596
25	Dover-Okeene 138 kV for the loss of Watonga Switch-Okeene 138 kV	31,598	67,870
26	Northwest-Matthewson 345 kV for the loss of Cimarron-Northwest 345 kV	8,735	90,442
27	Potter County-Bushland 230 kV for the loss of Potter County-Newhart 230 kV	40,973	54,835
28	Asbury-Carl Junction 161 kV for the loss of Asbury-Purcell SW 161 kV	49,042	46,588
29	Carlisle-LP-Doud 115 kV for the loss of Wolfforth 230/115 kV transformer	19,067	68,274
30	Craig-Lenexa 161 kV circuit 2 for the loss of Craig-Lenexa 161 kV circuit 1	11,679	60,043
31	Maryville-Clarinda 161 kV for the loss of Maryville E-Maryville 161 kV	0	58,191
32	Webb City Tap-Osage 138 kV for the loss of Sooner-Cleveland 345 kV	16,574	24,090
33	Waverly-La Cygne 345 kV for the loss of Caney River-Neosho 345 kV	12,412	6,813

Table 4.2: Future 2 Economic Needs

4.1.1 TARGET AREAS

As part of the economic needs assessment, two target areas were identified for the assessment to focus analysis efforts of staff and stakeholders. Drivers for these target areas included:

- Unresolved transmission limits identified in previous ITP assessments.
- Operational evaluation(s).
- Historical and projected congested flowgates in area.
- Steady-state reliability violations.
- Parallel and in-series relationships between flowgates/transmission corridors.
- Impacted heavily by critical EHV contingencies.
- Transient stability concerns for existing generators.

4.1.1.1 Southeast Kansas/Southwest Missouri Target Area (Target Area 1)

Southeast Kansas/southwest Missouri was identified as Target Area 1, requiring additional analysis for several reasons. The area has been the site of historic and projected congestion on the EHV system and has had unresolved transmission limits identified in multiple studies, most recently in the 2018 ITPNT. By defining this corridor as a target area in the 2019 ITP, SPP is able to address the TWG's direction to provide a path forward for the area to properly evaluate and resolve the issues present in day-to-day operations and in the planning horizon.

Continued integration of wind generation on the western side of the SPP system has contributed to diminishing transmission capacity capable of supporting bulk power transfers to the east. This has led to declining transient stability margins at the Wolf Creek nuclear plant. The Butler-Altoona 138 kV line in southeast Kansas, already known for its advanced age, was identified by NERC as having one of the highest outage rates for its voltage class. It regularly experiences high system flows during times of elevated wind output. The Neosho-Riverton 161 kV line to the south is also a common issue in real-time operations. The Wolf Creek 345/69 kV transformer, which supplies the 69 kV network of loads between Wolf Creek and Neosho, frequently experiences heavy congestion and loading when the Waverly-La Cygne line is outaged in both reliability and economic analyses.

Supplemental information posted in the needs assessment[15] outlined additional analysis needed to quantify the benefits of a comprehensive regional solution and to aid stakeholders in solution submittals.

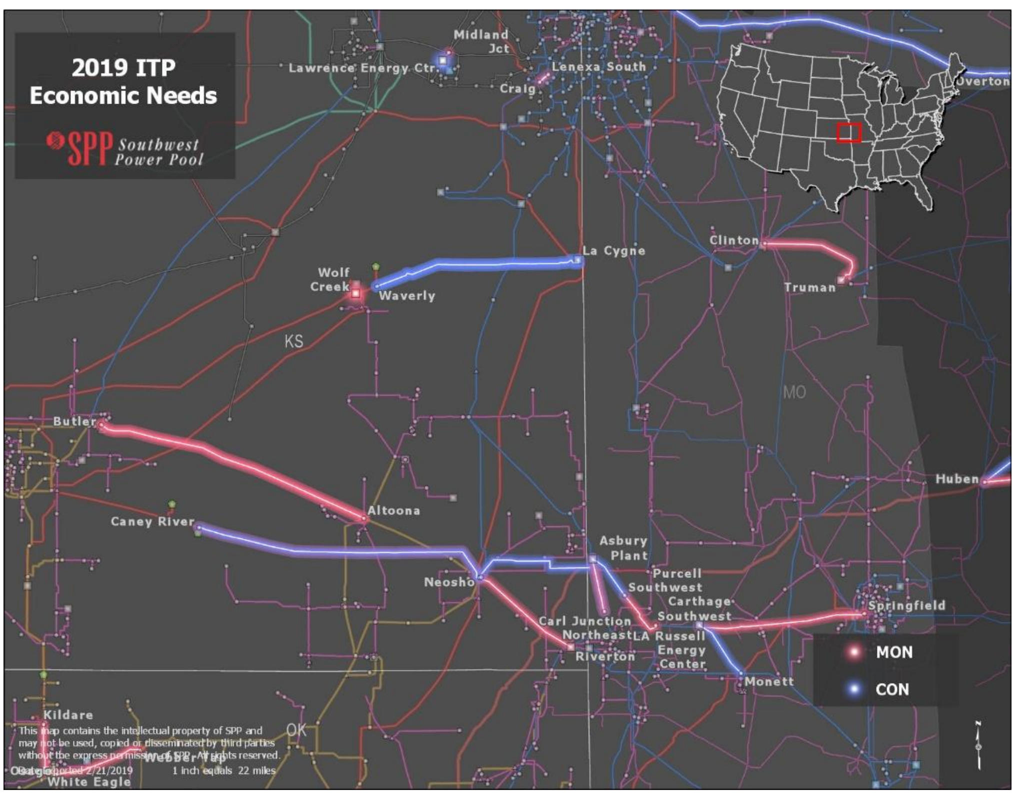


Figure 4.3: Southeast Kansas/Southwest Missouri Target Area Flowgates

[15] https://www.spp.org/documents/59347/2019_itp_needs_assessment_supplemental_information_(1.14.2019).pdf

Impactful Target Area 1 Constraints
Butler-Altoona 138 kV for the loss of Caney River-Neosho 345 kV
LaRussell-Springfield 161 kV for the loss of LaRussell-Monett 161 kV
Carthage SW-Purcell SW 161 kV for the loss of Ashbury-Carl Junction 161 kV
Asbury-Carl Junction 161 kV for the loss of Asbury-Purcell SW 161 kV
Wolf Creek 345/69 kV transformer for the loss of Waverly-La Cygne 345 kV
Neosho-Riverton 161 kV for the loss of Blackberry/RP2POI02-Neosho 345 kV
Neosho-RP2POI10 345 kV for the loss of Waverly-La Cygne 345 kV
Waverly-La Cygne 345 kV for the loss of Caney River-Neosho 345 kV

Table 4.3: Southeast Kansas/Southwest Missouri Target Area Flowgates

4.1.1.2 Central/Eastern Oklahoma Target Area (Target Area 2)

Central/eastern Oklahoma was identified as Target Area 2 due to heavy congestion and parallel system correlation with Target Area 1. Additional analysis was unnecessary for Target Area 2 because system issues in this area were only related to congestion and underlying voltage stability concerns. The main point of congestion in Target Area 2 is related to the Cleveland 345/138 kV station west of Tulsa, Oklahoma. The renewable forecast in the 2019 ITP drives increased bulk transfers across central Oklahoma. EHV contingencies in the area shift congestion mostly to the lower-voltage system.

Additional facilities that limit west-to-east transfers include the Webb Tap-Osage 138 kV path going west to east, north of the Tulsa area. The Northwest-Mathewson-Cimarron 345 kV line is also a limiting path. To achieve notable APC savings, bulk transfer paths must be improved in both target areas. To address congestion in this area, thermal limits need to be increased with rebuilds and terminal equipment or additional capacity to parallel to the most critical contingencies.

This target area was identified due to relationships with the transmission corridor east of Wichita, Kansas, connecting into Springfield, Missouri.

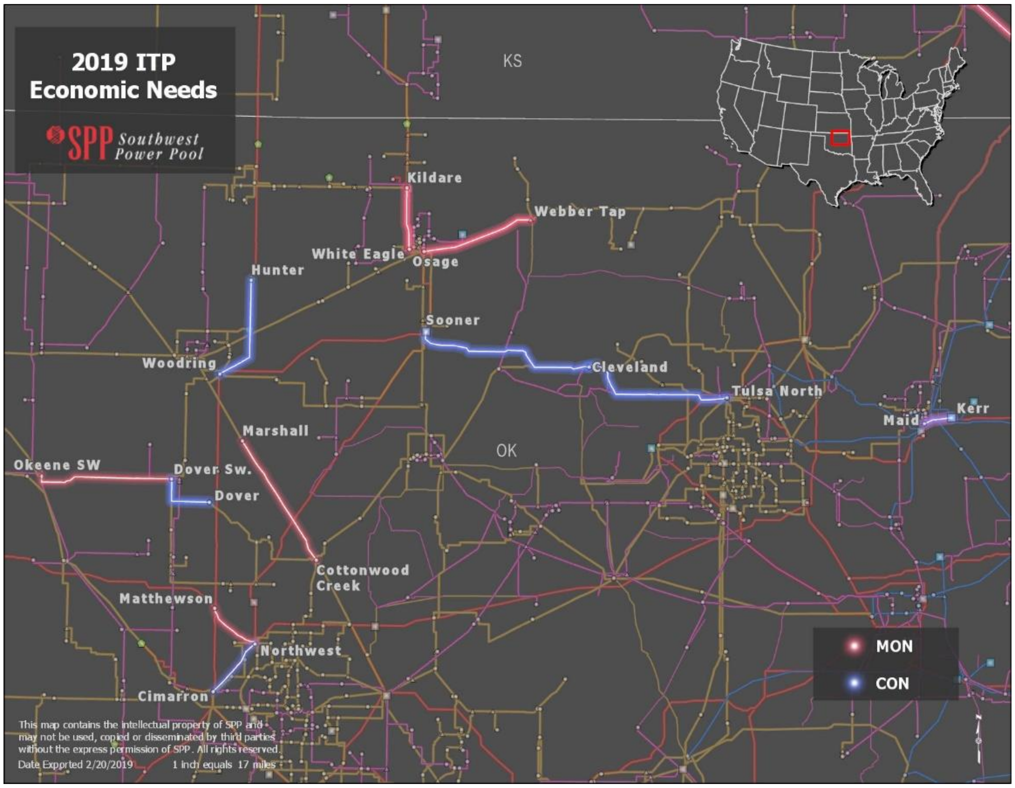


Figure 4.4: Central/Eastern Oklahoma Target Area Flowgates

Impactful Target Area 2 Constraints
Cleveland AECI-Cleveland GRDA 138 kV for the loss of Cleveland-Tulsa North 345 kV
Kerr-Maid 161 kV circuit 2 for the loss of Kerr-Maid 161 kV circuit 1
Webb City Tap-Osage 138 kV for the loss of Sooner-Cleveland 345 kV
Northwest-Matthewson 345 kV for the loss of Cimarron-Northwest 345 kV

Table 4.4: Central/Eastern Oklahoma Target Area Flowgates

4.2 RELIABILITY NEEDS

4.2.1 BASE RELIABILITY ASSESSMENT

SPP evaluated nine base reliability models. Three separate seasons (summer, winter, light load) were developed for years two, five and 10. Contingency analysis for the base reliability models consisted of analyzing P0, P1 and P2.1 planning events from Table 1 in the NERC TPL-001-4 standard, as well as remaining events that do not allow for non-consequential load loss (NCLL) or the interruption of firm transmission service (IFTS).

During the needs assessment, potential violations were solved or marked invalid through methods such as reactive device setting adjustments, model updates, identification of invalid contingencies, non-load-serving buses and facilities not under SPP's functional control. Figure 4.5 and Figure 4.6 summarize the number of remaining thermal and voltage needs[16] that were unable to be mitigated during the screening process.

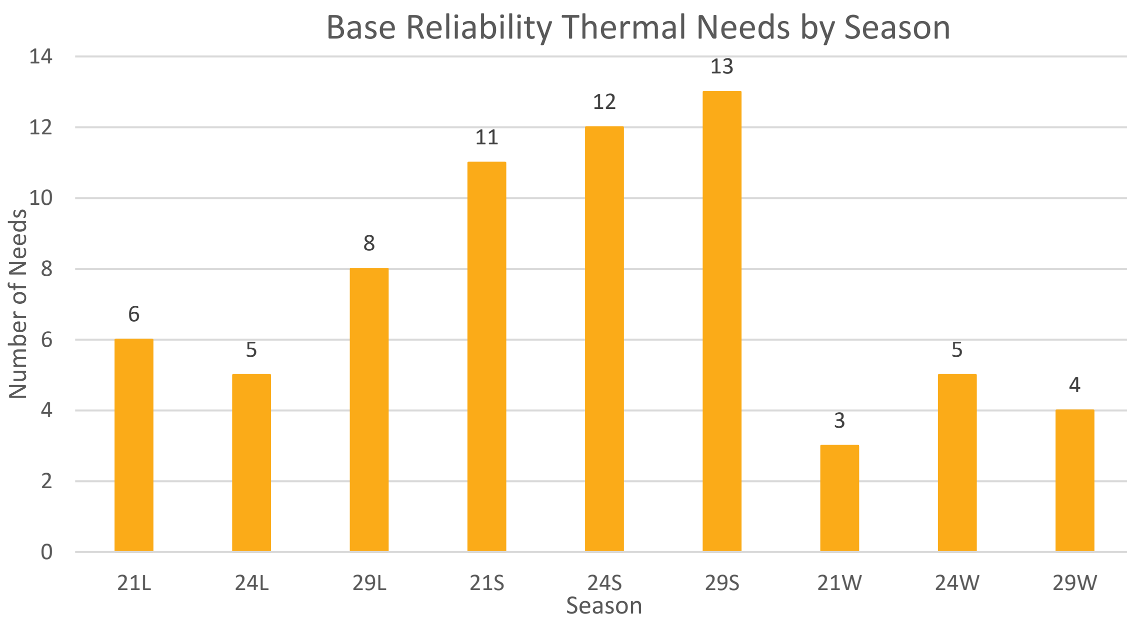


Figure 4.5: Unique Base Reliability Needs

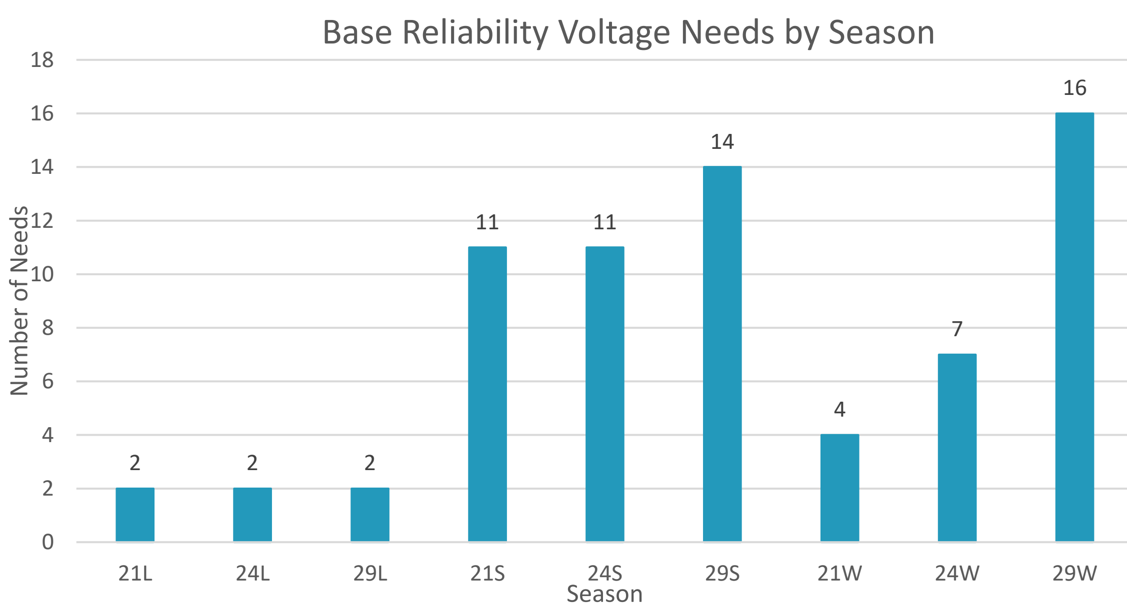


Figure 4.6: Unique Base Reliability Voltage Needs

[16] Figures summarize unique monitored elements.

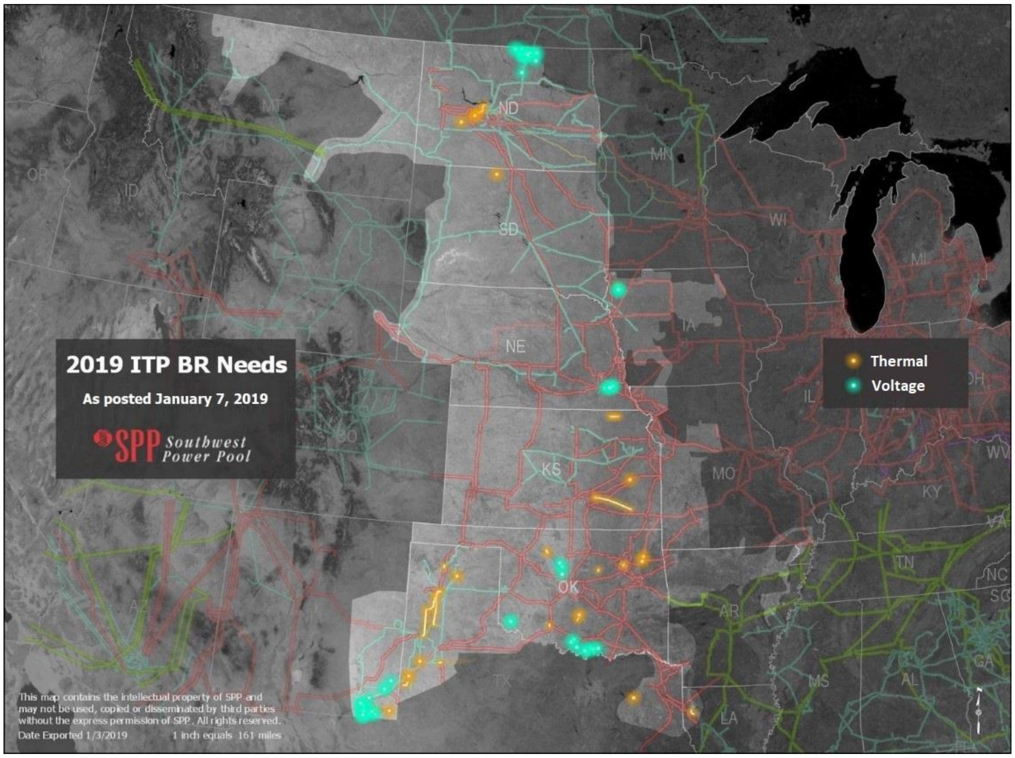


Figure 4.7: Base Reliability Needs

4.2.2 MARKET POWERFLOW ASSESSMENT

Contingency analysis for the market powerflow models consisted of analyzing P0, P1, and P2.1 planning events of varying voltage levels identified in NERC Standard TPL-001 Table 1 for each of the models. The 69 kV facilities that were selected for this portion of the study were identified in the constraint assessment.

The remaining contingencies in Table 1 of the NERC Standard TPL-001 that do not allow for NCLL or IFTS were analyzed only if a violation was observed in the same year and season of the base reliability models.

Figure 4.8 and Figure 4.9 summarize the number of remaining thermal and voltage needs[17] that were unable to be mitigated during the screening process.

[17] Figures summarize unique monitored elements

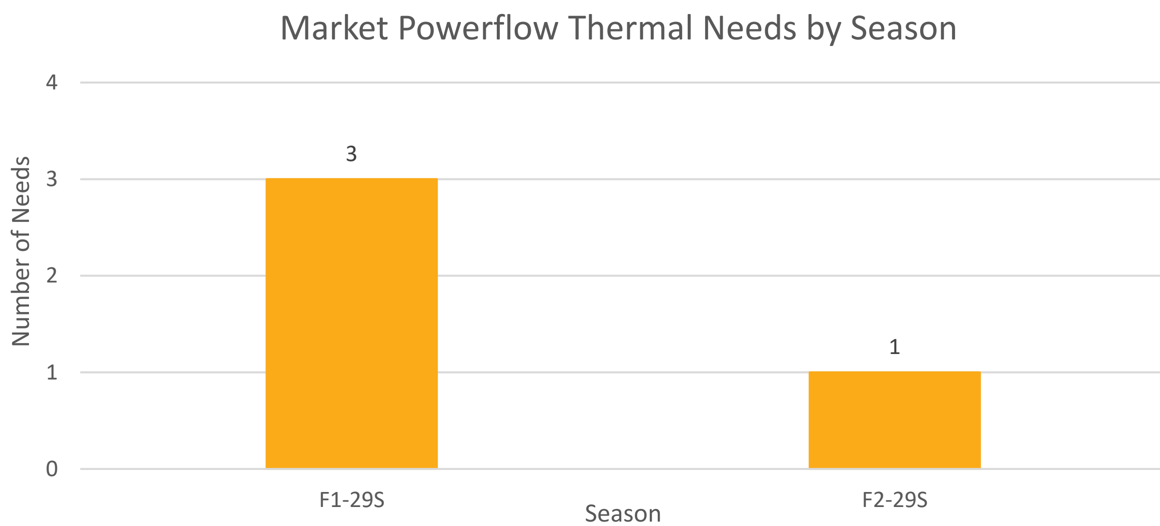


Figure 4.8: 2019 ITP Unique Market Powerflow Thermal Needs

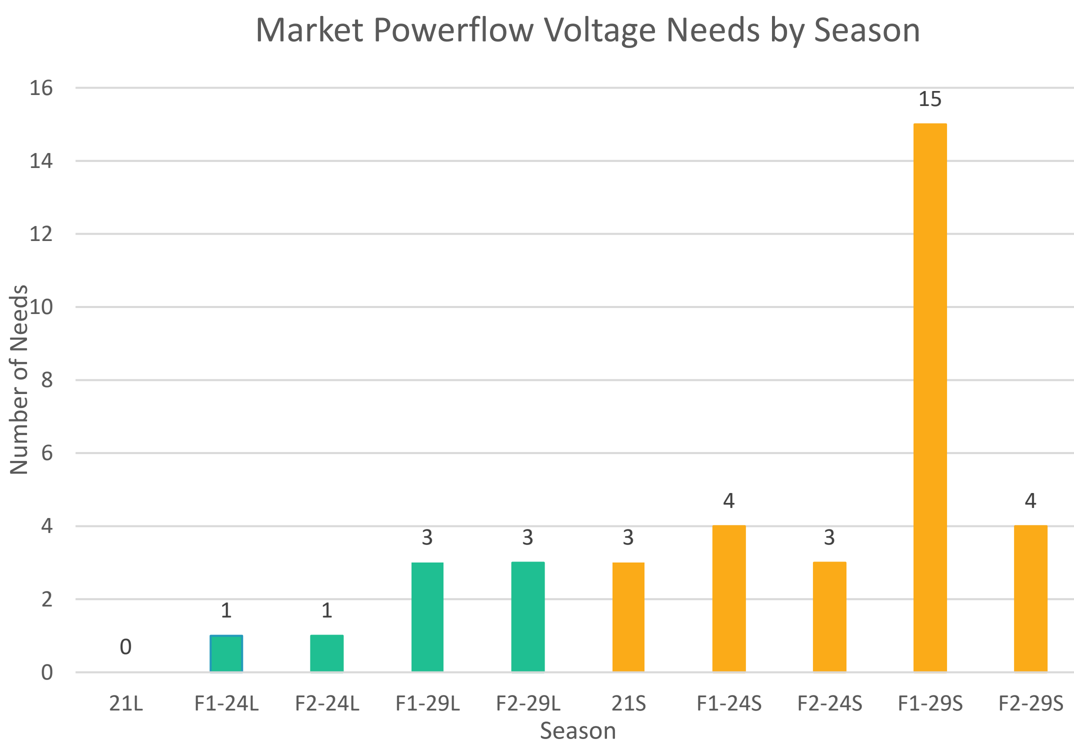


Figure 4.9: 2019 ITP Unique Market Powerflow Voltage Needs

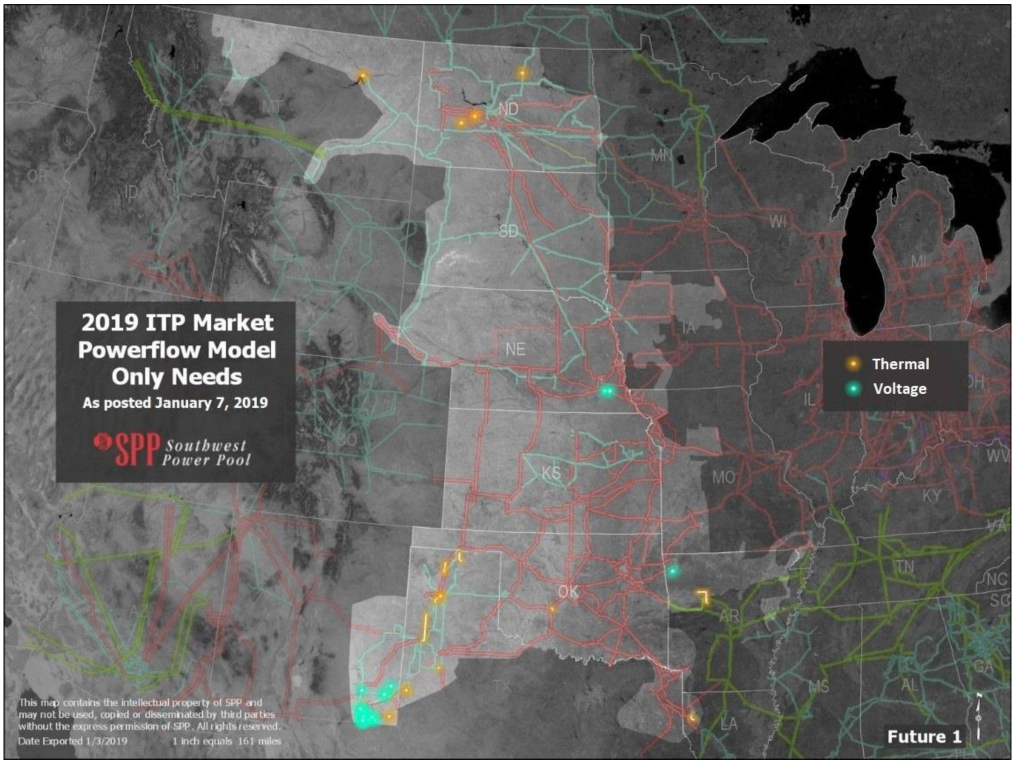


Figure 4.10: Future 1 Reliability Needs

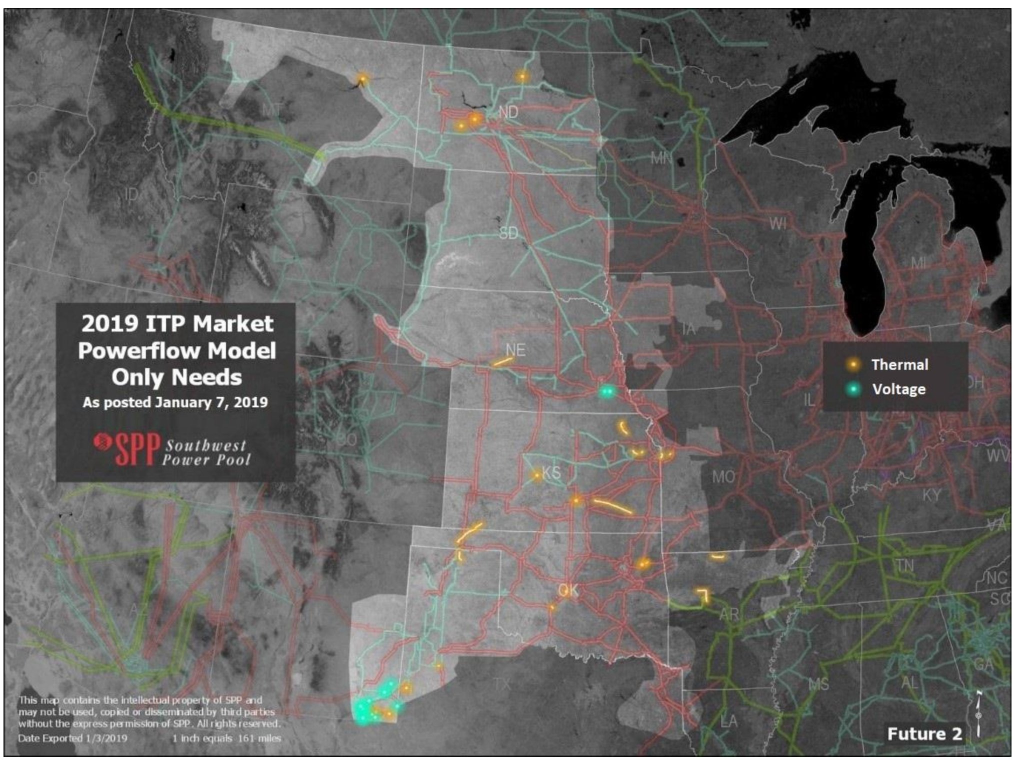


Figure 4.11: Future 2 Reliability Needs

4.2.3 NON-CONVERGED CONTINGENCIES

SPP used engineering judgment to resolve non-converged cases from the contingency analysis. Some non-converged cases could not be solved due to the contingency taken. Relative violations were identified as voltage collapse reliability needs in the applicable model and are listed in Table 4.5.

Model	Monitored Element	Contingent Element	Reliability Need
Base Reliability 2029 Summer Peak	Custer Mountain-Whitten 115 kV	Hobbs-Kiowa 345 kV	Thermal
Future 1 2024 Light Load	Eddy County 345 kV	Tolk-Crossroads 345 kV	Voltage
Future 2 2024 Light Load	Battle Axe 115 kV	Hobbs-Kiowa 345 kV	Voltage
Future 1 2029 Light Load	Battle Axe 115 kV	Hobbs-Kiowa 345 kV	Voltage
Future 2 2029 Light Load	Battle Axe 115 kV	Hobbs-Kiowa 345 kV	Voltage
Future 1 2029 Summer Peak	Battle Axe 115 kV	Hobbs-Kiowa 345 kV	Voltage
Future 2 2029 Summer Peak	Battle Axe 115 kV	Hobbs-Kiowa 345 kV	Voltage
Base Reliability 2029 Summer Peak	Battle Axe 115 kV	Hobbs-Kiowa 345 kV	Voltage
Future 2 2029 Summer Peak	North Loving 345 kV	Kiowa-North Loving 345 kV	Voltage

Table 4.5: Reliability Needs Resulting from Non-Converged Contingencies

4.2.4 SHORT-CIRCUIT ASSESSMENT

SPP provided the total bus fault current study results for single-line-to-ground (SLG) and three-phase faults to the Transmission Planners (TPs) for review.

The TPs were required to evaluate the results and indicate if any fault-interrupting equipment would have its duty ratings exceeded by the maximum available fault current. For equipment that would have its duty ratings exceeded, the TP provided the applicable duty rating of the equipment and the violation was identified as a short-circuit need.

The TPs can perform their own short-circuit analysis to meet the requirements of TPL-001. However, any corrective action plans that result in the recommended issuance of a Notification to Construct (NTC) are based on the SPP short-circuit analysis.

The short-circuit needs were comprised of 74 breakers housed in 18 substations across six SPP TP areas. They are depicted in Figure 4.12 below. The six TPs identifying short-circuit needs were American Electric Power (AEPW), Kansas City Power & Light Company (KCPL), Nebraska Public Power District (NPPD), Oklahoma Gas & Electric Company (OKGE), Southwestern Public Service Company (SPS), and Western Farmers Electric Cooperative (WFEC).

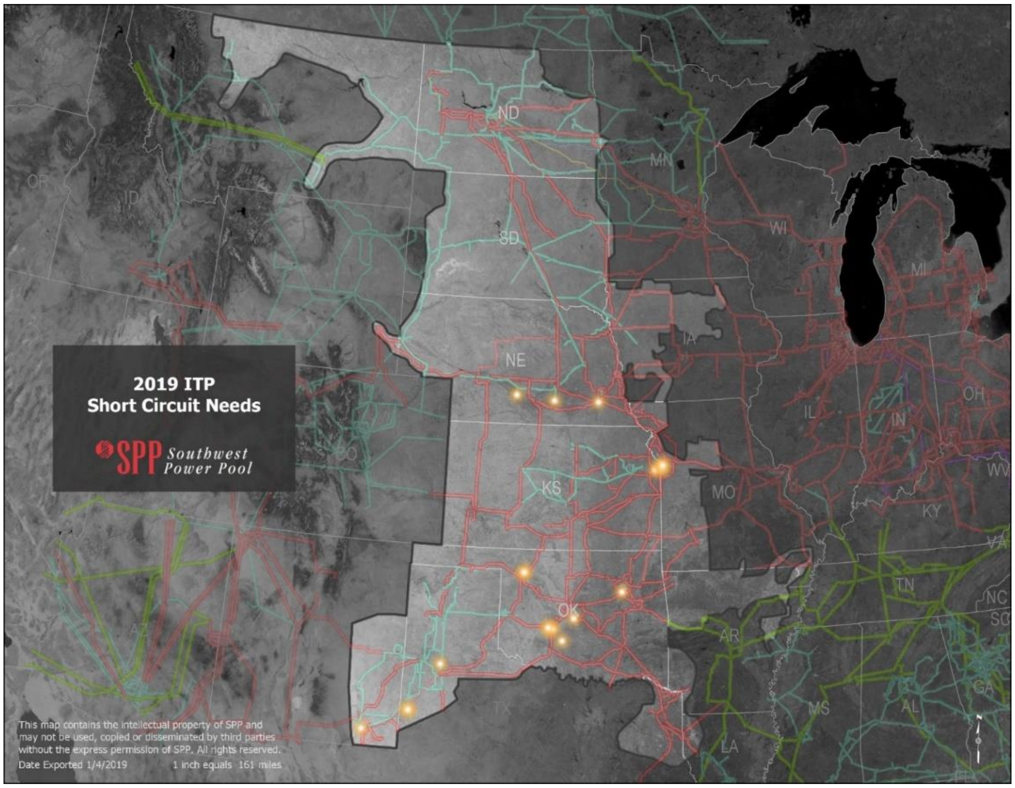


Figure 4.12: Short-Circuit Needs

4.3 PUBLIC POLICY NEEDS

Policy needs were analyzed based on the curtailment of renewable energy such that a Regulatory/Statutory Mandate or Goal identified in the renewable policy review is not able to be met. Policy needs are the result of the inability to dispatch renewable generation due to congestion, resulting in a utility-by-state not meeting its renewable Mandate or Goal. In spite of renewable curtailments, all utilities met their respective renewable Mandates and Goals, and thus there were no public policy needs..

4.3.1 METHODOLOGY

Policy needs were analyzed based on the curtailment of renewable energy such that a regulatory/statutory mandate or goal is not able to be met. Each zone with an energy mandate or goal was analyzed on a utility-by-state level (such as Basin Minnesota, Basin Montana, etc.) for renewable curtailments to determine if they met their mandate or goal. Policy needs are the result of an inability to dispatch renewable generation due to congestion, and any utility-by-state not meeting its renewable mandate or goal.

Renewable mandates and goals per utility were determined based on the renewable policy review. Mandates and goals for some states were based on installed capacity requirements only and were met by identifying capacity shortfalls and including the required capacity additions through phase one of the resource plan. It is not necessary to analyze curtailment to ensure capacity requirements are met. Therefore, they are not used to identify public policy needs.

4.3.2 POLICY NEEDS

Future 1, 2021						
Utility	**State**	**Renewable Type**	**Curtailed Energy (TWh)**	**Energy Mandate Contribution (TWh)**	**Energy Mandate Requirement (TWh)**	**Surplus (TWh)**
SPCUIT	MO	Wind, Solar	0.0	8.2	4.7	3.5
EMDE	MO	Wind, Solar	1.4	10.1	7.7	2.4
GMO	MO	Wind, Solar	0.4	16.0	12.6	3.4
KCPL	MO	Wind, Solar	0.0	1.0	0.5	0.6
NPPD	SD	Wind, Solar	0.0	14.3	12.3	2.1
WFECSPS	NM	Wind	0.0	0.1	0.0	0.1
WFECSPS	NM	Solar	0.1	7.0	3.5	3.5
SPS	NM	Wind	0.0	2.3	0.9	1.3
SPS	NM	Solar	0.1	18.9	13.3	5.6
BASIN	MN	Wind, Solar	0.0	4.0	3.6	0.4
BASIN	MT	Wind, Solar	0.0	1.6	1.1	0.5
BASIN	ND	Wind, Solar	0.0	1.7	1.1	0.6
BASIN	SD	Wind, Solar	0.3	35.6	11.4	24.2
HCPD	MN	Wind, Solar	0.3	14.4	6.1	8.3
CBPC	ND	Wind, Solar	0.0	0.8	0.5	0.4
NWPS	SD	Wind, Solar	0.0	0.3	0.0	0.3
MRES	MN	Wind, Solar	0.0	4.9	2.4	2.5
MRES	ND	Wind, Solar	0.0	0.7	0.5	0.2
MRES	SD	Wind, Solar	0.0	0.5	0.1	0.5

Table 4.6: Policy Assessment Results: Future 1, 2021

Future 1, 2024						
Utility	**State**	**Renewable Type**	**Curtailed Energy (TWh)**	**Energy Mandate Contribution (TWh)**	**Energy Mandate Requirement (TWh)**	**Surplus (TWh)**
SPCUIT	MO	Wind, Solar	0.0	8.2	4.7	3.5
EMDE	MO	Wind, Solar	1.4	10.1	7.7	2.4
GMO	MO	Wind, Solar	0.4	16.0	12.6	3.4
KCPL	MO	Wind, Solar	0.0	1.0	0.5	0.6
NPPD	SD	Wind, Solar	0.0	14.3	12.3	2.1
WFECSPS	NM	Wind	0.0	0.1	0.0	0.1
WFECSPS	NM	Solar	0.1	7.0	3.5	3.5
SPS	NM	Wind	0.0	2.3	0.9	1.3
SPS	NM	Solar	0.1	18.9	13.3	5.6
BASIN	MN	Wind, Solar	0.0	4.0	3.6	0.4
BASIN	MT	Wind, Solar	0.0	1.6	1.1	0.5
BASIN	ND	Wind, Solar	0.0	1.7	1.1	0.6
BASIN	SD	Wind, Solar	0.3	35.6	11.4	24.2
HCPD	MN	Wind, Solar	0.3	14.4	6.1	8.3
CBPC	ND	Wind, Solar	0.0	0.8	0.5	0.4
NWPS	SD	Wind, Solar	0.0	0.3	0.0	0.3
MRES	MN	Wind, Solar	0.0	4.9	2.4	2.5
MRES	ND	Wind, Solar	0.0	0.7	0.5	0.2
MRES	SD	Wind, Solar	0.0	0.5	0.1	0.5

Table 4.7: Policy Assessment Results: Future 1, 2024

Future 1, 2029						
Utility	**State**	**Renewable Type**	**Curtailed Energy (TWh)**	**Energy Mandate Contribution (TWh)**	**Energy Mandate Requirement (TWh)**	**Surplus (TWh)**
SPCUIT	MO	Wind, Solar	1.9	6.8	4.7	2.1

Future 1, 2029						
Utility	**State**	**Renewable Type**	**Curtailed Energy (TWh)**	**Energy Mandate Contribution (TWh)**	**Energy Mandate Requirement (TWh)**	**Surplus (TWh)**
EMDE	MO	Wind, Solar	1.1	8.7	7.8	0.9
GMO	MO	Wind, Solar	0.4	17.2	12.6	4.6
KCPL	MO	Wind, Solar	0.1	0.9	0.5	0.4
NPPD	SD	Wind, Solar	0.4	13.8	12.1	1.6
WFECSPS	NM	Wind	0.0	0.1	0.0	0.1
WFECSPS	NM	Solar	0.1	7.0	3.9	3.1
SPS	NM	Wind	0.0	2.3	1.0	1.2
SPS	NM	Solar	0.0	18.9	14.3	4.7
BASIN	MN	Wind, Solar	0.0	8.9	3.8	5.1
BASIN	MT	Wind, Solar	0.0	1.6	1.4	0.2
BASIN	ND	Wind, Solar	0.0	1.7	1.2	0.5
BASIN	SD	Wind, Solar	0.3	35.6	12.1	23.5
HCPD	MN	Wind, Solar	0.1	14.5	6.5	8.0
CBPC	ND	Wind, Solar	0.0	0.8	0.6	0.2
NWPS	SD	Wind, Solar	0.0	0.3	0.0	0.3
MRES	MN	Wind, Solar	0.0	4.9	2.6	2.3
MRES	ND	Wind, Solar	0.0	0.7	0.7	0.1
MRES	SD	Wind, Solar	0.0	0.5	0.1	0.5

Table 4.8: Policy Assessment Results: Future 1, 2029

Future 2, 2024						
Utility	**State**	**Renewable Type**	**Curtailed Energy (TWh)**	**Energy Mandate Contribution (TWh)**	**Energy Mandate Requirement (TWh)**	**Surplus (TWh)**
SPCUIT	MO	Wind, Solar	0.0	8.4	4.8	3.6
EMDE	MO	Wind, Solar	2.8	9.1	7.9	1.2

Future 2, 2024						
Utility	**State**	**Renewable Type**	**Curtailed Energy (TWh)**	**Energy Mandate Contribution (TWh)**	**Energy Mandate Requirement (TWh)**	**Surplus (TWh)**
GMO	MO	Wind, Solar	1.1	15.0	12.9	2.2
KCPL	MO	Wind, Solar	0.0	0.8	0.5	0.4
NPPD	SD	Wind, Solar	0.0	14.3	12.5	1.8
WFECSPS	NM	Wind	0.0	0.1	0.0	0.1
WFECSPS	NM	Solar	0.3	6.8	3.7	3.0
SPS	NM	Wind	0.0	2.8	1.0	1.8
SPS	NM	Solar	0.6	18.4	14.0	4.5
BASIN	MN	Wind, Solar	0.0	4.0	3.7	0.2
BASIN	MT	Wind, Solar	0.0	1.6	1.1	0.5
BASIN	ND	Wind, Solar	0.0	1.7	1.1	0.5
BASIN	SD	Wind, Solar	0.2	35.6	11.6	24.1
HCPD	MN	Wind, Solar	0.3	14.3	6.2	8.1
CBPC	ND	Wind, Solar	0.0	0.8	0.5	0.3
NWPS	SD	Wind, Solar	0.0	0.3	0.0	0.3
MRES	MN	Wind, Solar	0.0	4.9	2.5	2.4
MRES	ND	Wind, Solar	0.0	0.7	0.5	0.2
MRES	SD	Wind, Solar	0.0	0.5	0.1	0.5

Table 4.9: Policy Assessment Results: Future 2, 2024

Future 2, 2029						
Utility	**State**	**Renewable Type**	**Curtailed Energy (TWh)**	**Energy Mandate Contribution (TWh)**	**Energy Mandate Requirement (TWh)**	**Surplus (TWh)**
SPCUIT	MO	Wind, Solar	3.7	5.5	4.9	0.6
EMDE	MO	Wind, Solar	2.7	8.4	8.1	0.3
GMO	MO	Wind, Solar	0.5	17.4	13.1	4.3

Future 2, 2029						
Utility	**State**	**Renewable Type**	**Curtailed Energy (TWh)**	**Energy Mandate Contribution (TWh)**	**Energy Mandate Requirement (TWh)**	**Surplus (TWh)**
KCPL	MO	Wind, Solar	0.1	0.7	0.5	0.3
NPPD	SD	Wind, Solar	0.2	14.1	12.6	1.5
WFECSPS	NM	Wind	0.0	0.1	0.0	0.1
WFECSPS	NM	Solar	0.1	7.0	4.1	3.0
SPS	NM	Wind	0.0	2.8	1.1	1.7
SPS	NM	Solar	0.1	18.8	14.8	4.0
BASIN	MN	Wind, Solar	0.0	13.4	3.9	9.4
BASIN	MT	Wind, Solar	0.0	1.6	1.5	0.1
BASIN	ND	Wind, Solar	0.0	1.7	1.2	0.5
BASIN	SD	Wind, Solar	0.3	35.6	12.5	23.1
HCPD	MN	Wind, Solar	0.1	14.5	6.7	7.8
CBPC	ND	Wind, Solar	0.0	0.8	0.6	0.2
NWPS	SD	Wind, Solar	0.0	0.3	0.0	0.3
MRES	MN	Wind, Solar	0.0	4.9	2.7	2.2
MRES	ND	Wind, Solar	0.0	0.7	0.7	0.0
MRES	SD	Wind, Solar	0.0	0.5	0.1	0.5

Table 4.10: Policy Assessment Results: Future 2, 2029

All utilities met their overall renewable mandates and goals. There were no public policy needs and thus no policy solutions identified in any of the futures.

4.4 PERSISTENT OPERATIONAL NEEDS

4.4.1 ECONOMIC OPERATIONAL NEEDS

In October 2018, the MOPC approved a waiver of the requirement to evaluate solutions against the economic operational needs in the 2019 ITP assessment due to identified software limitations. The economic operational needs identified for the 2019 ITP assessment in Table 4.11 through Table 4.14 were posted for informational purposes only.

Constraint	Monitored Element	Contingent Element	Congestion Cost
TMP270_23432	Cleveland 138 kV GRDA-AECI Bus Tie	Cleveland-Tulsa North 345 kV	$28,004,877
TMP228_22196 HALTUCSWITUC	Hale-Tuco 115 kV	Swisher-Tuco 230 kV	$19,687,942
TMP269_23661	Charlie Creek-Watford 230 kV	Charlie Creek-Patent Gate 345 kV	$17,724,562
TMP151_23193	Oakland North-Atlas Junction 161 kV	Asbury-Purcell 161 kV	$17,129,796
TMP103_22587	Kildare-White Eagle 138 kV	Hunter-Woodring 345 kV	$15,869,305
TMP192_21680	Smoky Hills-Summit 230 kV	Postrock-Axtell 345 kV	$13,006,107
TEMP39_23235	Waverly-La Cygne 345 kV	Caney River-Neosho 345 kV	$11,754,041
JECAUBHOYJEC	Jeffrey-Auburn 230 kV	Jeffrey-Hoyt 345 kV	$10,373,715
TEMP96_22409 HUGVALHUGVAL	Hugo-Valliant 138 kV	Hugo-Valliant 345 kV	$10,267,443

Table 4.11: Economic Operational Needs

The constraints in Table 4.12 have associated future upgrades which are expected to reduce some or all congestion associated with the constraint.

Constraint	Monitored Element	Contingent Element	Congestion Cost	Notes
SUNAMOTOLYOA	Sundown-Amoco 230 kV	Tolk-Yoakum 230 kV	$22,121,967	NTC ID 200395, Issued 5/17/2016, 2016 ITPNT, Sundown-Amoco terminal equipment, Q1 2019 ISD
NEORIVNEOBLC	Neosho-Riverton 161 kV	Neosho-Blackberry 345 kV	$20,483,694	NTC ID 200430, Issued 2/21/2017, 2017 ITP10, Neosho and Riverton 161 kV terminal equipment, 12/2018 ISD

Constraint	Monitored Element	Contingent Element	Congestion Cost	Notes
GGS	Gentleman-Red Willow 345 kV Gentleman-Sweetwater 345 kV circuit 1 Gentleman-Sweetwater 345 kV circuit 2 Gentleman-North Platte 230 kV circuit 1 Gentleman-North Platte 230 kV circuit 2 Gentleman-North Platte 230 kV circuit 3	System Intact	$15,769,205	NTC ID 200220, Issued 3/11/2013, 2012 ITP10, Gentleman-Cherry Co.-Holt 345 kV
HANMUSAGEPEC	Hancock-Muskogee 161 kV	Pecan-Agency 161 kV	$13,737,915	NTC ID 200423, Issued 1/12/2017, 2016-AG1, 6/1/2021 ISD, Hancock-Muskogee terminal equipment
TEMP60_22466	Tuco-Stanton 115 kV	Tuco-Carlisle 230 kV	$11,531,235	NTC ID 200444, Issued 2/22/2017, 2017 ITP10, 12/31/2018 ISD (Delay-Mitigation), Tuco-Stanton-Indiana-Erskine terminal equipment

Table 4.12: Economic Operational Needs

The constraints in Table 4.13 have associated upgrades currently in place which have reduced or eliminated loading of the associated constraint.

Constraint	Monitored Element	Contingent Element	Congestion Cost	Notes
WDWFPLTATNOW	Woodward-Windfarm Switching Station 138 kV	Tatonga-Matthewson 345 kV circuit 1	$86,155,466	NTC ID 200223, Issued 5/23/2013, 2012 ITP10, Woodward-Tatonga-Matthewson 345 kV circuit 2, 2/15/2018 ISD, $665,000 congestion cost (outage related) since upgrade
PLXSUNTOLYOA	Plant X-Sundown 230 kV	Tolk-Yoakum 230 kV	$56,046,773	NTC ID 200455, Issued 5/12/2017, 2017 ITPNT, Plant X and

Constraint	Monitored Element	Contingent Element	Congestion Cost	Notes
				Sundown 230 kV terminal equipment, 3/28/2018 ISD, $0 congestion cost since upgrade
TMP215_21787	Cimarron-Draper 345 kV	Terry Road-Sunnyside 345 kV	$41,040,182	NTC ID 200416, Issued 11/14/2016, 2015 ITP10, Cimarron-Draper terminal equipment, 11/28/2017 ISD, $0 congestion cost since upgrade
TMP118_22847	Southard-Roman Nose 138 kV	Tatonga-Matthewson 345 kV circuit 1	$34,561,487	NTC ID 200223, Issued 5/23/2013, 2012 ITP10, Woodward-Tatonga-Matthewson 345 kV circuit 2, 2/15/2018 ISD, $0 congestion cost since upgrade
VINHAYPOSKNO SHAHAYPOSKNO	Vine Tap-North Hays 115 kV	Post Rock-Knoll 230 kV	$30,519,207	NTC ID 200429, Issued 2/22/2017, 2017 ITP10, Post Rock-Knoll circuit 2, 12/2018 ISD
TMP171_22413	Mooreland-Cedardale 138 kV	Tatonga-Matthewson 345 kV circuit 1	$24,889,894	NTC ID 200223, Issued 5/23/2013, 2012 ITP10, Woodward-Tatonga-Matthewson 345 kV circuit 2, 2/15/2018 ISD, $0 congestion cost since upgrade
TMP113_22583	Cimarron-Draper 345 kV	Arcadia-Seminole 345 kV	$14,666,763	NTC ID 200416, Issued 11/14/2016, 2015 ITP10, terminal equipment, 11/28/2017 ISD, $0 congestion cost since upgrade

Table 4.13: Economic Operational Needs

4.4.2 RELIABILITY OPERATIONAL NEEDS

A reconfiguration for voltage mitigation in the southwest Missouri area was the single reliability operational need identified for the 2019 ITP assessment. This need was previously addressed in the 2018

ITPNT and is associated with a planned upgrade. As such, this need was posted for informational purposes only for the 2019 ITP planning cycle.

Reconfiguration	Type	Annual Reconfiguration (%)	Notes
Brookline-Flint Creek 345 kV opened for high voltage during light loading	Voltage	24.27%	NTC ID 210493, Issued 8/17/2018, 2018 ITPNT, 12/31/2019 ISD, New 50 MVAR reactor at Brookline 345 kV

Table 4.14: Reliability Operational Needs

4.5 NEED OVERLAP

Relationships identified among the various need types aid in development of the most valuable regional solutions. SPP staff identified relationships among the economic needs to both the base reliability needs and informational economic operational needs.

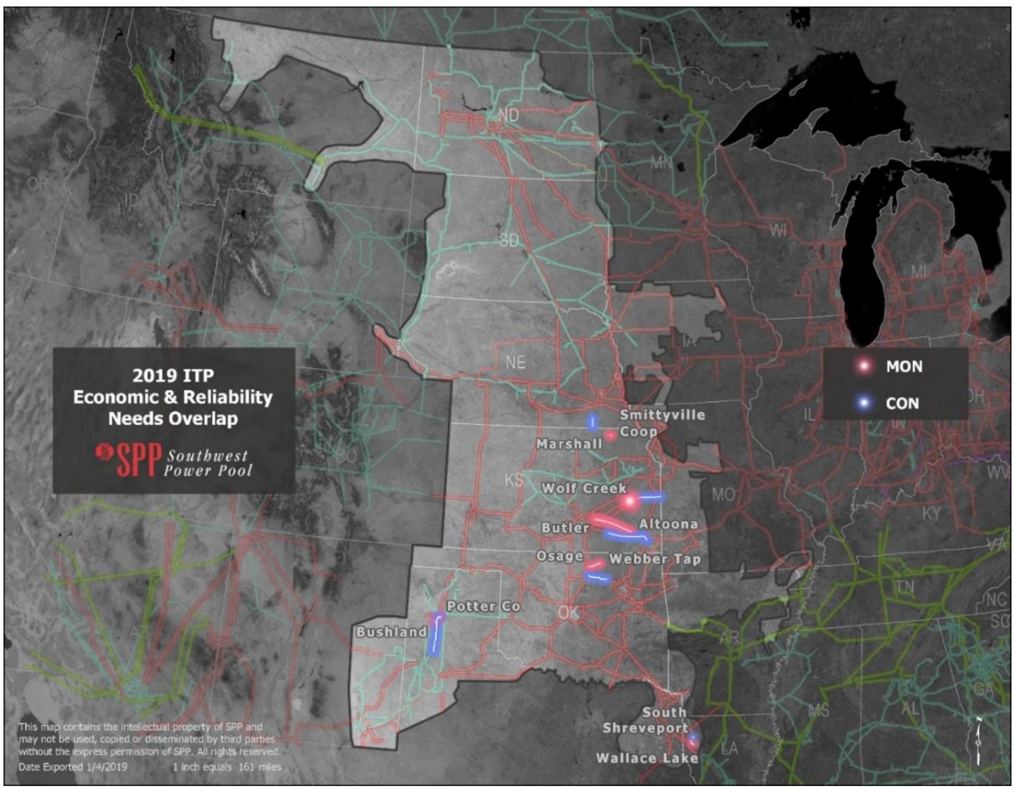


Figure 4.13: Base Reliability and Economic Need Overlap

Overlapping Reliability and Economic Needs
Wolf Creek 345/69 kV transformer for the loss of Waverly-La Cygne 345 kV
Butler-Altoona 138 kV for the loss of Caney River-Neosho 345 kV
Webb City Tap-Osage 138 kV for the loss of Sooner-Cleveland 345 kV
South Shreveport-Wallace Lake 138 kV for the loss of Ft. Humbug-Trichel 138 kV
Potter County-Bushland 230 kV for the loss of Potter County-Newhart 230 kV

Overlapping Reliability and Economic Needs
Marshall-Smittyville 115 kV for the loss of Harbine-Steele 115 kV
Carlisle-LP-Doud 115 kV for the loss of Wolfforth 230/115 kV transformer

Table 4.15: Overlapping Reliability and Economic Needs

Overlapping Informational Operational and Economic Needs
Neosho-Riverton 161 kV for the loss of Blackberry-Neosho 345 kV
Cleveland AECI-Cleveland GRDA 138 kV for the loss of Cleveland-Tulsa North 345 kV
Waverly-La Cygne 345 kV for the loss of Caney River-Neosho 345 kV
Hale County-Tuco 115 kV for the loss of Swisher-Tuco 230 kV
Kildare-White Eagle 138 kV for the loss of Woodring-Hunter 345 kV
Hugo-Valliant 138 kV for the loss of Valliant-Hugo 345 kV
Oakland North-Atlas Junction 161 kV for the loss of Asbury-Purcell 161 kV*

Table 4.16: Overlapping Informational Operational and Economic Needs

4.6 ADDITIONAL ASSESSMENTS

Additional assessments were performed to satisfy SPP tariff requirements involving parts of the transmission system that were not included in the approved model sets.

4.6.1 RAYBURN COUNTRY ELECTRIC COOPERATIVE

The Rayburn Country Electric Cooperative (Rayburn Country) transmission system and network load in the American Electric Power-West (AEPW) pricing zone that is involved in regulatory processes to move to the Electric Reliability Council of Texas (ERCOT) system was not included in the approved base models sets. While this is the future expectation, SPP has the obligation to protect long-term firm transmission service to serve the load until the delivery points are removed from the current network integration transmission service agreement (NITSA).

To satisfy this obligation, following the same analysis of the reliability needs assessment, an analysis was performed on the base reliability model set with the Rayburn Country system and network load included. This analysis identified no new potential transmission needs and therefore had no impact to the 2019 ITP assessment.

4.6.2 TRI-COUNTY ELECTRIC COOPERATIVE (TCEC)

The Tri-County Electric Cooperative (Tri-County) transmission system in the Oklahoma panhandle within the transmission SPS/Xcel Energy pricing zone came under SPP functional control via the requirements of Attachment AI of the tariff following the 2019 ITP model build. This system has been previously equivalenced prior to SPP model build that began in the fall of 2018. GridLiance High Plains (GLHP) performed its local planning process assessment in 2018 and identified three new transmission upgrades required to meet local planning process needs. To satisfy its own NERC and tariff requirements, GLHP requested SPP to expedite the requirements under FAC-002 and Attachment O, Section II.1(e), of the tariff to perform a no-harm analysis on the proposed upgrades and coordinate the upgrades with the potential solutions of the 2019 ITP assessment.

An analysis was performed to satisfy these obligations by determining the impact of including the explicitly modeled Tri-County system and proposed local planning process upgrades in the 2019 ITP base reliability and market economic model sets. Following the same analysis of the reliability and economic needs assessments, no new potential transmission needs were identified by including the existing system or the proposed local planning process upgrades. No regional transmission needs or projects identified in the 2019 ITP assessment were located geographically or electrically close to the Tri-County system.

5 SOLUTION DEVELOPMENT AND EVALUATION

Solutions were evaluated in each applicable scenario and modeled to determine their effectiveness in mitigating the needs identified in the needs assessment. The project solutions assessed included the Federal Energy Regulatory Commission (FERC) Order 1000 and Order 890 solutions submitted by stakeholders, SPP staff, projects submitted in previous planning studies, and model adjustments/ corrections. MISO staff also provided a subset of solutions identified in the 2019 MTEP for evaluation in SPP models. Staff analyzed 1,073 Detailed Project Proposals (DPP) solutions received from stakeholders and approximately 560 staff solutions (including those provided by MISO and additional solutions developed during portfolio development). SPP staff members developed a standardized conceptual cost template to calculate a conceptual cost estimate for each project to utilize during screening.

5.1 RELIABILITY PROJECT SCREENING

Solutions were tested in each powerflow model to determine their ability to mitigate reliability criteria violations in the study horizon. To be considered effective, a solution must have been able to address the needs such that the identified facilities were within acceptable limits defined in the SPP Criteria and a member's more stringent local planning criteria. Figure 5.1 illustrates the reliability project screening process.

Reliability metrics developed by SPP staff and stakeholders and approved by the TWG were calculated for each project and used as a tool to aid in developing a portfolio of projects to address all reliability needs. The first metric is cost per loading relief (CLR) score, which relates the amount of thermal loading relief a solution provides to its engineering and construction cost. The second metric is cost per voltage relief (CVR) score, which relates the amount of voltage support a solution provides to its engineering and construction cost.

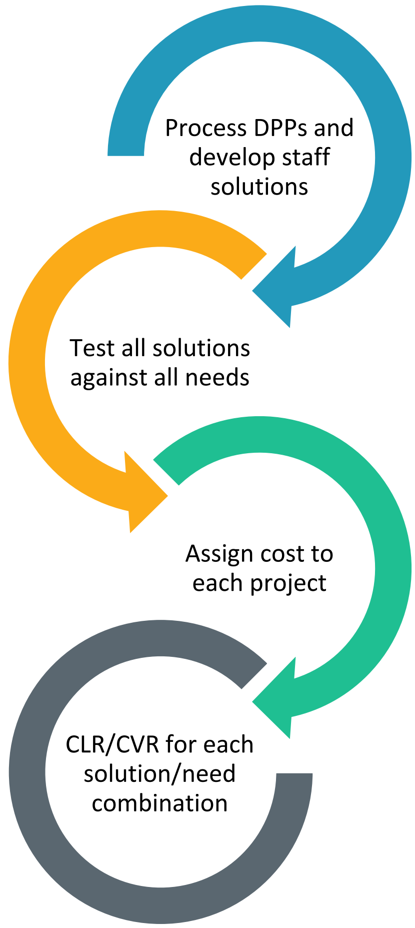


Figure 5.1: Reliability Screening Process

5.2 ECONOMIC PROJECT SCREENING

All solutions were tested in each market economic model to determine their effectiveness in mitigating transmission congestion in the study horizon. A one-year benefit-to-cost (B/C) ratio and a 40-year net present value (NPV) benefit-to-cost ratio were calculated for each project based on its projected APC savings in each future and study year (2021, 2024, and 2029).

The annual change in APC for all SPP pricing zones is considered the one-year benefit to the SPP region for each study year. The one-year benefit is divided by the one-year cost of the project to develop a benefit-to-cost ratio for each project. The one-year cost, or projected annual transmission revenue requirement (ATRR) is calculated using a historical SPP average net plant carrying charge (NPCC) multiplied by the project conceptual cost. The NPCC used for this assessment was 17.44%. The 40-year project cost is calculated using this NPCC, an 8% discount rate and a 2.5% inflation rate.

The correlation of congestion in different areas of the system was identified and accounted for during the economic screening process. Where appropriate, this included adding new flowgates to screening simulations to ensure potential congestion created by projects would be captured, as well as pairing certain projects to ensure correlated congestion would be resolved by a more comprehensive solution set. These adjustments ensure the projected benefits of projects are not over- or under-stated.

5.3 SHORT-CIRCUIT PROJECT SCREENING

Solutions submitted to address overdutied breakers were reviewed to ensure the updated breaker ratings submitted were greater than the maximum available fault current identified in the short-circuit needs assessment.

5.4 PUBLIC POLICY PROJECT SCREENING

No public policy needs were identified in the 2019 ITP; therefore, no projects were analyzed during the public policy project screening.

5.5 PERSISTENT OPERATIONAL PROJECT SCREENING

Due to the MOPC-approved waiver described in section 4.4.1, no projects were analyzed during persistent operational project screening.

6 PORTFOLIO DEVELOPMENT

6.1 PORTFOLIO DEVELOPMENT PROCESS

Figure 6.1 shows a high-level overview of the portfolio development process. The process starts with the utilization of project metric results in project grouping and continues through the development of a consolidated portfolio that comprehensively addresses the system's needs.

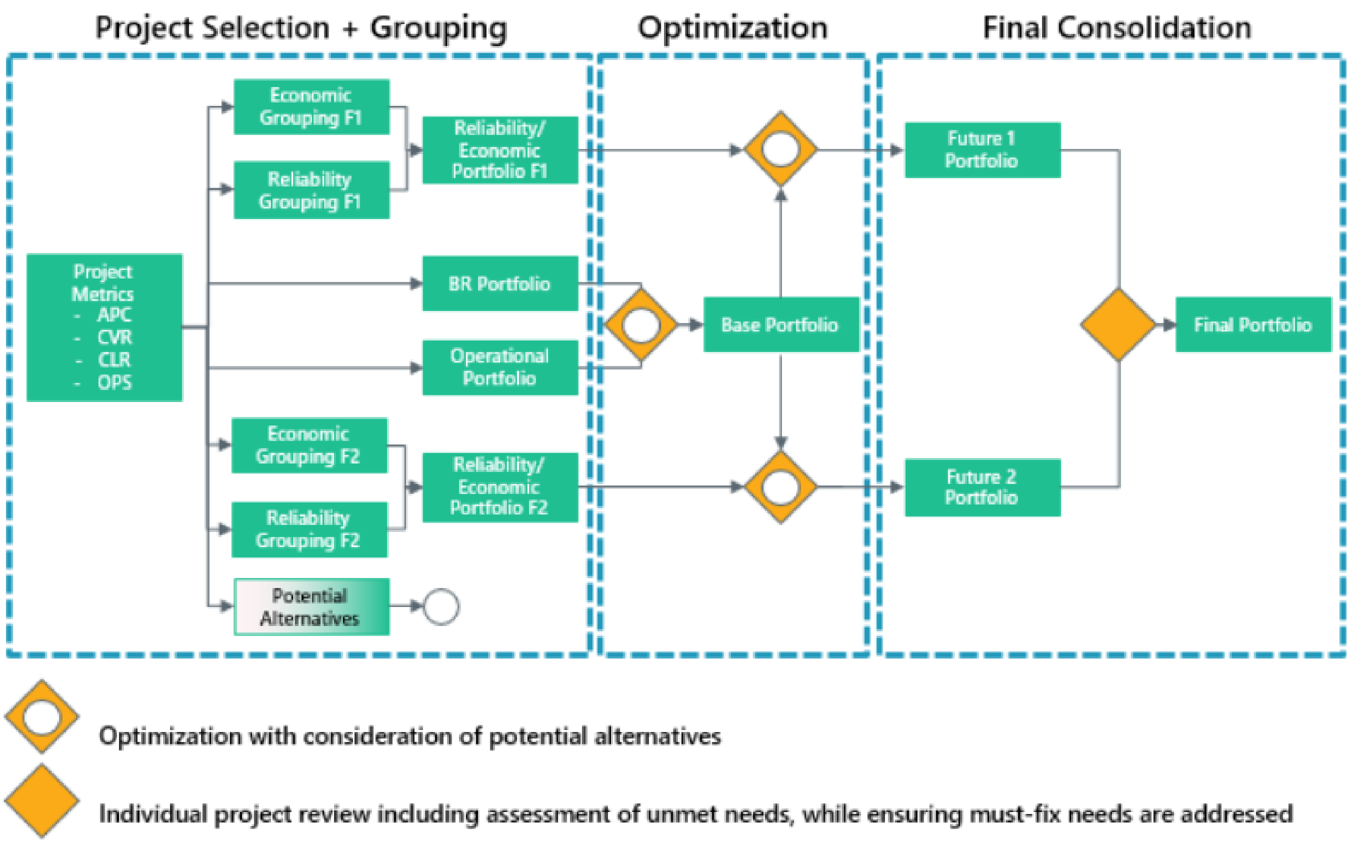


Figure 6.1: Portfolio Development Process

6.2 PROJECT SELECTION AND GROUPING

Once all solutions were screened, draft groupings were developed in parallel to address the different need types across the system. SPP used study level cost estimates and stakeholder feedback from regularly scheduled working group meetings, the June 2019 SPP transmission planning summit, and SPP's Request Management System.

6.2.1 STUDY ESTIMATES

Solutions that performed well using the screening assessments described in Section Solution Development and Evaluation were sent out for the development of study cost estimates (±30% of final project cost). Individual project upgrades with the potential to be deemed competitive were sent to a third-party cost estimator. Remaining project upgrades were sent to the incumbent member utility. SPP requested these study estimates before and after the June summit. Once the study estimates were received, that cost was used for the remainder of the portfolio development process.

6.2.2 RELIABILITY GROUPING

A programmatic method was used to compare the metric results for the extensive number of solutions. Using this solution selection software, a subset of solutions was generated by considering the metrics described in Section 5.1. During this iterative process, SPP staff applied engineering judgment to develop a draft list of selected and high-performing alternate solutions. This analysis was performed for each of the base, Future 1, and Future 2 reliability needs.

While reviewing these results, it was determined there were no facilities unique to the futures scenarios that required solutions different from the base reliability results. Therefore, the iterative process was streamlined to consider all needs as a single grouping. The list of reliability solutions was continually refined through stakeholder feedback. Table 6.1 and Figure 6.2 below shows the final reliability grouping selected to address the valid list of reliability needs in the 2019 ITP.

Project	Area	Cost	Scenario[18]*
Pryor Junction 138/115 kV transformer	AEPW	$9,155,167	21S / BR,F1,F2
Tulsa SE-21 St Tap 138 kV rebuild	AEPW	$1,307,802	21S / BR
Tulsa SE-S Hudson 138 kV rebuild	AEPW	$6,724,237	21S / BR
Firth 15MVAR capacitor bank 115 kV	NPPD	$3,370,000	21S,W,L / BR,F1,F2
Cleo Corner-Cleo Junction 69 kV terminal equipment	OKGE	$16,602	24S / BR
Rocky Point-Marietta 69 kV terminal equipment	OKGE/ WFEC	$100,000	21W / BR
Bushland-Deaf Smith 230 kV terminal equipment	SPS	$1,185,094	29L / BR
Carlisle-LP Doud Tap 115 kV terminal equipment	SPS	$88,924	29S / BR
Deaf Smith-Plant X 230 kV terminal equipment	SPS	$1,185,094	29L / BR
Lubbock South-Jones 230 kV circuit 1 terminal equipment	SPS	$88,924	29S / BR
Lubbock South-Jones 230 kV circuit 2 terminal equipment	SPS	$88,924	29S / BR
Moore-RB-S&S 115 kV terminal equipment	SPS	$158,742	29S / BR,F1
Plains Interchange-Yoakum 115 kV terminal equipment	SPS	$158,742	29S / BR

[18] This is the first need date.

Project	Area	Cost	Scenario[18]*
Potter Co-Newhart 230 kV terminal equipment	SPS	$1,185,094	29L / BR
Marshall County-Smittyville-Baileyville-South Seneca 115 kV rebuild	WERE	$17,636,022	21L / BR
Getty East-Skelly 69 kV terminal equipment	WERE	$114,821	21S,W,L / BR
Gypsum 12 MVAR capacitor bank 69 kV	WFEC	$490,093	21S / BR

Table 6.1: Reliability Project Grouping

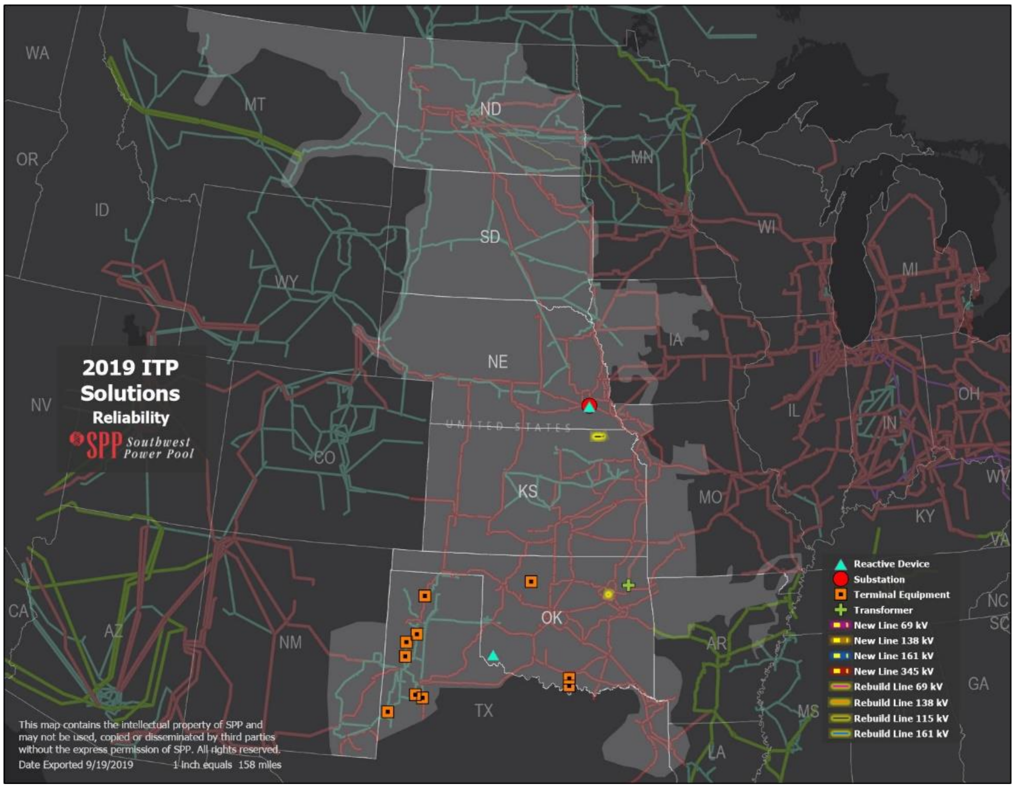


Figure 6.2: Reliability Project Grouping

6.2.3 SHORT-CIRCUIT GROUPING

The solutions submitted to address overdutied breakers identified in the short-circuit needs assessment were grouped together as a set of solutions to address the short-circuit needs. No testing was required for these solutions because the submitted breaker upgrades only need to be rated higher than the maximum fault current identified in the needs assessment. Table 6.2 summarizes the final short-circuit grouping, while Figure 6.3 shows the approximate location of identified projects within the SPP footprint.

Reliability Project	Area	Cost	Scenario*
Replace 21 breakers at Riverside Station 138 kV	AEPW	$16,288,000	21S / BR

Replace 8 breakers at Southwestern Station 138 kV	AEPW	$4,421,345	21S / BR
Replace 1 breaker at Craig 161 kV	KCPL	$254,000	21S / BR
Replace 2 breakers at Leeds 161 kV	KCPL	$440,000	21S / BR
Replace 2 breakers at Midtown 161 kV	KCPL	$440,000	21S / BR
Replace 4 breakers at Southtown 161 kV	KCPL	$880,000	21S / BR
Replace 1 breaker at Moore 13.8 kV tertiary bus	NPPD	$510,000	21S / BR
Replace 2 breakers at Hastings 115 kV	NPPD	$550,000	21S / BR
Replace 5 breakers at Canaday 115 kV	NPPD	$2,600,000	21S / BR
Replace 2 breakers at Westmoore 138 kV	OKGE	$271,289	21S / BR
Replace 3 breakers at Santa Fe 138 kV	OKGE	$406,935	21S / BR
Replace 1 breaker at Carlsbad Interchange 115 kV	SPS	$552,668	21S / BR
Replace 3 breakers at Denver City North and South 115 kV	SPS	$5,526,680	21S / BR
Replace 3 breakers at Hale County Interchange 115 kV	SPS	$1,658,004	21S / BR
Replace 1 breaker at Washita 69 kV	WFEC	$52,400	21S / BR
Replace 12 breakers at Mooreland 138/69 kV	WFEC	$835,850	21S / BR
Replace 3 breakers at Anadarko 138 kV	WFEC	$228,500	21S / BR

Table 6.2: Short-Circuit Project Grouping

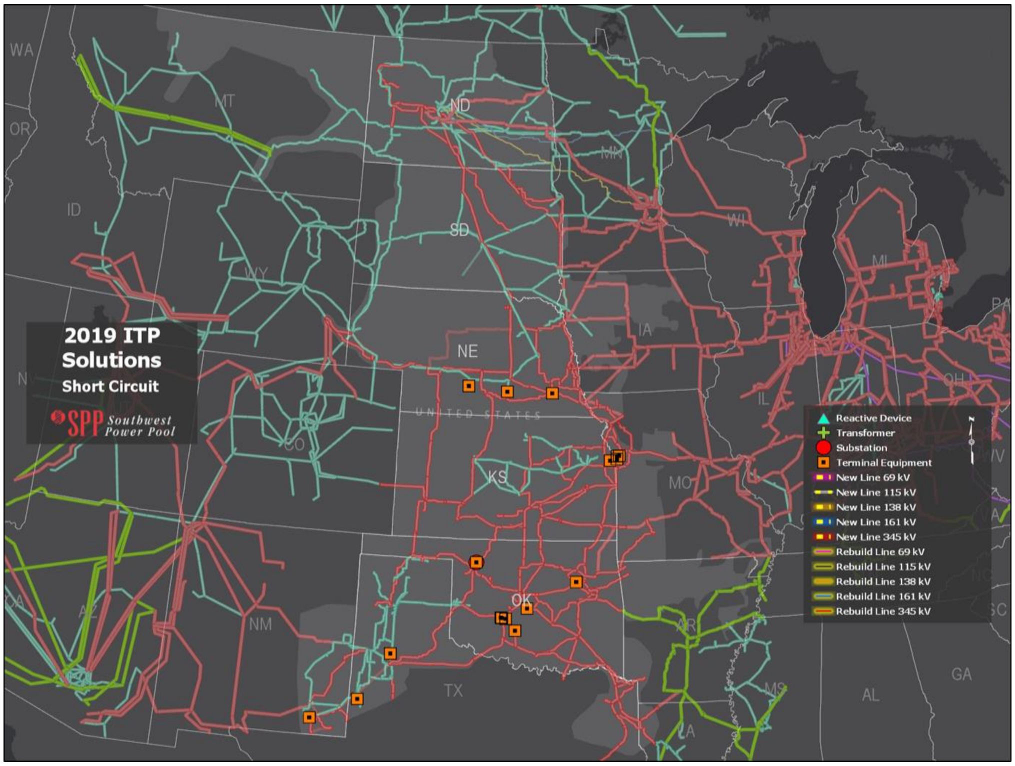


Figure 6.3: Short-Circuit Project Grouping

6.2.4 ECONOMIC GROUPING

All projects with a one-year benefit-to-cost ratio of at least 0.5 or a 40-year NPV benefit-to-cost ratio of at least 1.0 during the project screening phase were further evaluated while developing project groupings. Projects were evaluated and grouped based on one-year project cost, one-year APC benefit, 40-year project cost, 40-year NPV benefit-to-cost ratio, and congestion relief for the economic needs.

Three economic project groupings were developed for Futures 1 and 2, resulting in six total groupings:

1. Cost-Effective (CE): Projects with the lowest cost per congestion cost relief for a single economic need
2. Highest Net APC Benefit (HN): Projects with the highest APC benefit minus project cost, with consideration of overlap if multiple projects mitigate congestion on the same economic needs
3. Multi-variable (MV): Projects selected using data from the two other groupings; includes the flexibility to use additional considerations.

The following factors were considered when developing and analyzing projects grouping per future:

- One-year project cost, APC benefit, and benefit-to-cost ratio.
- 40-year NPV cost, APC benefit, and the benefit-to-cost ratio.
- Congestion relief a project provides for the economic needs of that future and year.
- Project overlap, or when two or more projects that relieve the same congestion are in a single portfolio.
- Potential for a project to mitigate multiple economic needs.

- Any potential routing or environmental concerns with projects.
- Any long-term concerns about the viability of projects.
- Seams and non-seams project overlap.
- Relief of downstream and/or upstream issues, tested by event file modification.
- Potential for a project to mitigate reliability, operational or public policy needs, which covers current market congestion.
- Potential for a project to address non-thermal issues.
- Need for new infrastructure versus leveraging existing infrastructure.
- Larger-scale solutions that provide more robustness and additional qualitative benefits.

Table 6.3 identifies a comprehensive list of economic projects included in the six initial groupings. Some projects appeared in multiple groupings.

	Future 1			Future 2		
Economic Project	CE	HN	MV	CE	HN	MV
Upgrade Wolf Creek 345/69 kV transformer	X	-	-	X	-	-
New Wolf Creek-Blackberry 345 kV line, new Butler 138 kV phase-shifting transformer	-	X	-	-	X	-
Tap Neosho-La Cygne and New Wolf Creek-New Tap-Blackberry 345 kV line, new Butler 138 kV phase-shifting transformer	-	-	X	-	-	X
New Butler 138 kV phase-shifting transformer	X	X	X	X	X	X
Neosho-Riverton 161 kV rebuild	X	X	X	X	X	X
Waverly-La Cygne 345 kV reconductor	X	-	-	X	-	-
Neosho-Caney River 345 kV terminal equipment	X	X	X	X	X	X
Springfield-La Russell 161 kV rebuild	X	X	X	X	X	X
Cleveland 138 kV bus tie terminal equipment	X	-	-	X	-	-
Kerr-Maid 161 kV double circuit rebuild	X	X	X	X	X	X
Osage-Webb Tap-Fairfax-Shidler 138 kV rebuild	X	-	-	X	-	-
Kinzie 138 kV bus tie terminal equipment	X	-	-	X	-	-
New Sooner-Wekiwa 345 kV line, Sand Springs-Sheffield Steel 138 kV terminal equipment	-	X	X	-	X	X
Cimarron-Northwest-Matthewson 345 kV terminal equipment	X	X	X	X	X	X
Hugo-Valliant 138 kV terminal equipment	-	-	-	X	X	X
South Brown-Russett 138 kV rebuild	-	-	-	X	X	X
Gracemont-Anadarko 138 kV rebuild	X	X	X	X	X	X
Cottonwood Creek-Cottonwood Creek-Marshall Tap 138 kV rebuild	-	-	-	X	X	X
Kingfisher Jct.-East Kingfisher Tap 138 kV rebuild	X	X	X	X	X	X
Dover Switch-Okeene 138 kV rebuild	X	X	X	X	X	X
Sundown-Amoco Tap 115 kV terminal equipment	X	X	X	X	X	X
Spearman-Hansford 115 kV rebuild	X	X	X	X	X	X
Carlisle-LP Doud 115 kV terminal equipment	-	-	-	X	X	X
Lawrence EC-Midland 115 kV terminal equipment	X	X	X	X	X	X
Craig-Lenexa 161 kV circuit 2 reconductor	-	-	-	X	X	X
Arnold-Ransom 115 kV terminal equipment, Pile-Scott City-Setab 115 kV terminal equipment	-	-	-	X	X	X
Upgrade Red Willow 345/115 kV transformer	-	-	-	X	X	X
Upgrade Fort Thompson 345/230 kV transformer circuits 1 and 2	-	-	-	X	X	X
Erie Road-Marshall re-termination and dynamically rate Granite Falls-Marshall 115 kV line	X	X	X	-	-	-

Table 6.3: Economic Project Grouping

Figure 6.4 provides a benefit-to-cost comparison (including a B/C ratio) of the six initial groupings. All costs and benefits are reported in 40-year NPVs. Based on these initial results, the highest net grouping was the best performing grouping for both futures 1 and 2. The calculated B/C ratios for each grouping are also shown in the figure.

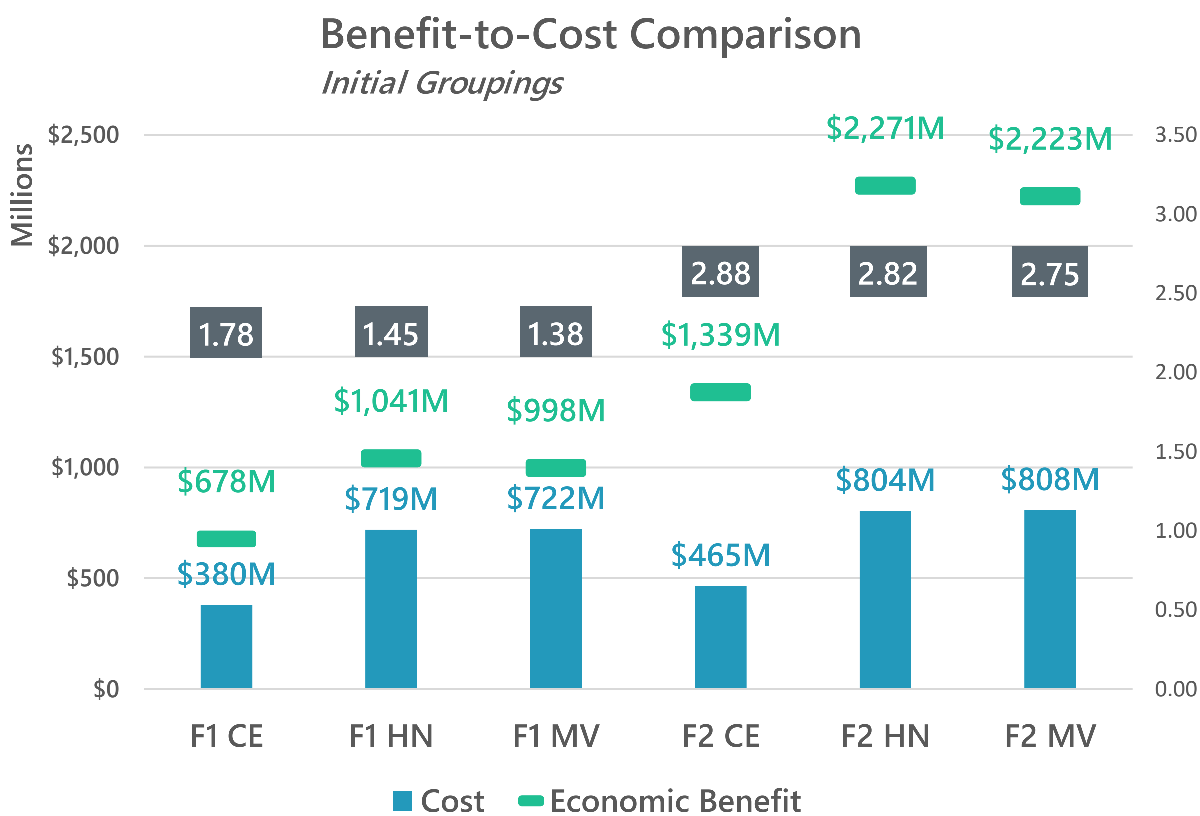


Figure 6.4: Benefit-to-Cost Comparison – Initial Groupings

6.2.4.1 Project Subtraction Evaluation

Draft groupings were developed using project screening results, which tests projects by incrementally adding changes to the base market economic models. When assessing a group of economic solutions, it is necessary to re-evaluate project performance within the grouping to ensure the projected APC benefit of each project in the grouping remains. “Subtraction evaluation” is used to identify when multiple projects can provide congestion relief to a constraint or projects that are dependent on each other to relieve overall system congestion. Six new sets of “base cases” were created by adding the solutions included in each grouping along with relevant model adjustments, corrections, and reliability projects required to meet the future’s needs. All economic projects were then removed from the models individually to determine each project’s APC impact compared to the new base case. Projects that did not meet a 1.0 benefit-to-cost ratio from the subtraction evaluation were removed from the grouping. This subtraction evaluation was repeated for each grouping until all remaining projects maintained a benefit-to-cost ratio of 1.0 over 40 years.

The final result of the subtraction evaluation resulted in the selection of a future one and Future 2 groupings that provided the highest overall net benefit.

6.2.4.2 Final Economic Groupings

The selected grouping for each future was the grouping that provided the highest net benefit when comparing APC savings to the cost of the projects. The cost-effective grouping was selected for Future 1, while the highest net grouping was selected for Future 2. Table 6.4 shows the final list of projects included in each grouping. Figure 6.5 and Figure 6.6 show the approximate location of identified projects within the SPP footprint.

	Future 1			Future 2		
Economic Project	**CE**	**HN**	**MV**	**CE**	**HN**	**MV**
Upgrade Wolf Creek 345/69 kV transformer	X	-	-	X	-	-
New Wolf Creek-Blackberry 345 kV line and New Butler 138 kV phase-shifting transformer	-	X	-	-	X	-
Tap Neosho-La Cygne and New Wolf Creek-New Tap-Blackberry 345 kV line and New Butler 138 kV phase-shifting transformer	-	-	X	-	-	X
New Butler 138 kV phase-shifting transformer	X	-	-	X	-	-
Neosho-Riverton 161 kV rebuild	-	X	X	-	X	-
Waverly-La Cygne 345 kV reconductor	-	-	-	X	-	-
Neosho-Caney River terminal equipment	-	X	-	X	X	X
Cleveland 138 kV bus tie terminal equipment	X	-	-	X	-	-
Osage-Webb Tap 138 kV rebuild	-	-	-	X	-	-
New Sooner-Wekiwa 345 kV line and Sand Springs-Sheffield Steel 138 kV terminal equipment	-	X	X	-	X	X
Cimarron-Northwest-Matthewson 345 kV terminal equipment	X	X	X	X	X	X
South Brown-Russett 138 kV rebuild	-	-	-	-	X	X
Gracemont-Anadarko 138 kV rebuild	X	X	X	X	X	X
Cottonwood Creek-Cottonwood Creek-Marshall Tap 138 kV rebuild	-	-	-	X	-	-
Kingfisher Jct.-East Kingfisher Tap 138 kV rebuild	X	X	X	X	X	X
Dover Switch-Okeene 138 kV rebuild	-	X	-	X	-	-
Sundown-Amoco Tap 115 kV terminal equipment	X	X	-	-	-	-
Spearman-Hansford 115 kV rebuild	X	X	X	X	X	X
Lawrence EC-Midland 115 kV terminal equipment	X	X	X	X	X	X
Craig-Lenexa 161 kV circuit 2 reconductor	-	-	-	X	-	-
Arnold-Ransom 115 kV terminal equipment and Pile-Scott City-Setab 115 kV terminal equipment	-	-	-	X	X	X
Upgrade Fort Thompson 345/230 kV transformer circuits 1 and 2	-	-	-	X	X	X
Erie Road-Marshall re-termination and dynamically rate Granite Falls-Marshall 115 kV line	-	-	-	X	X	X

Table 6.4: Final Economic Project Grouping

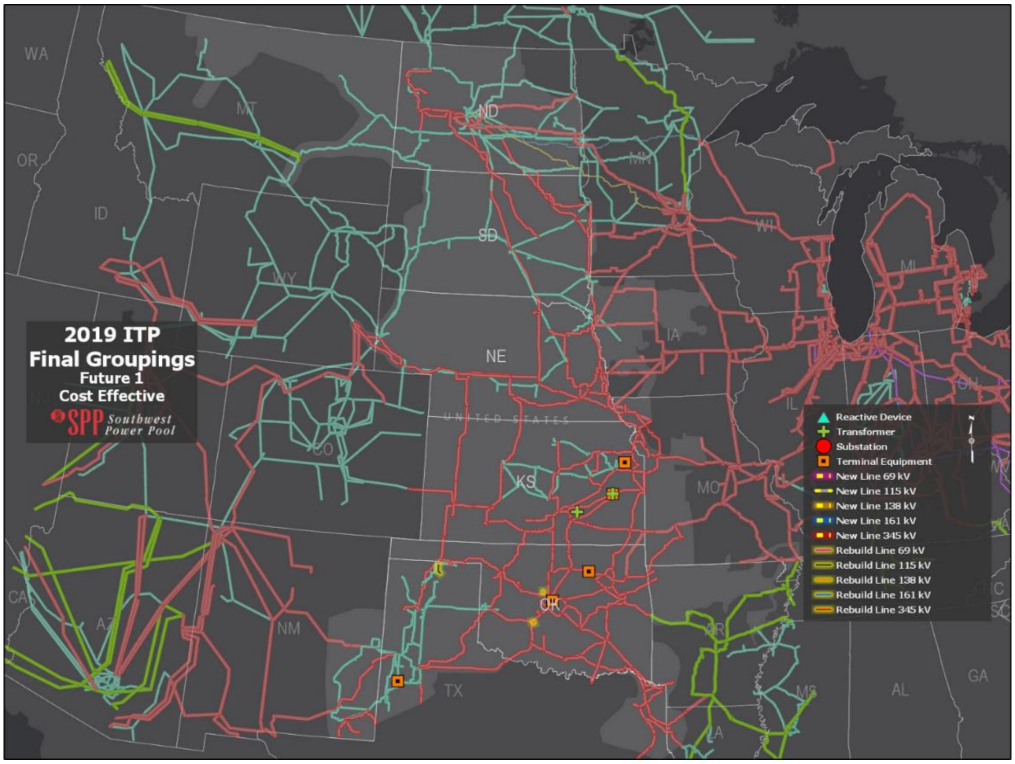


Figure 6.5: Final Project Groupings - Future 1 - Cost Effective

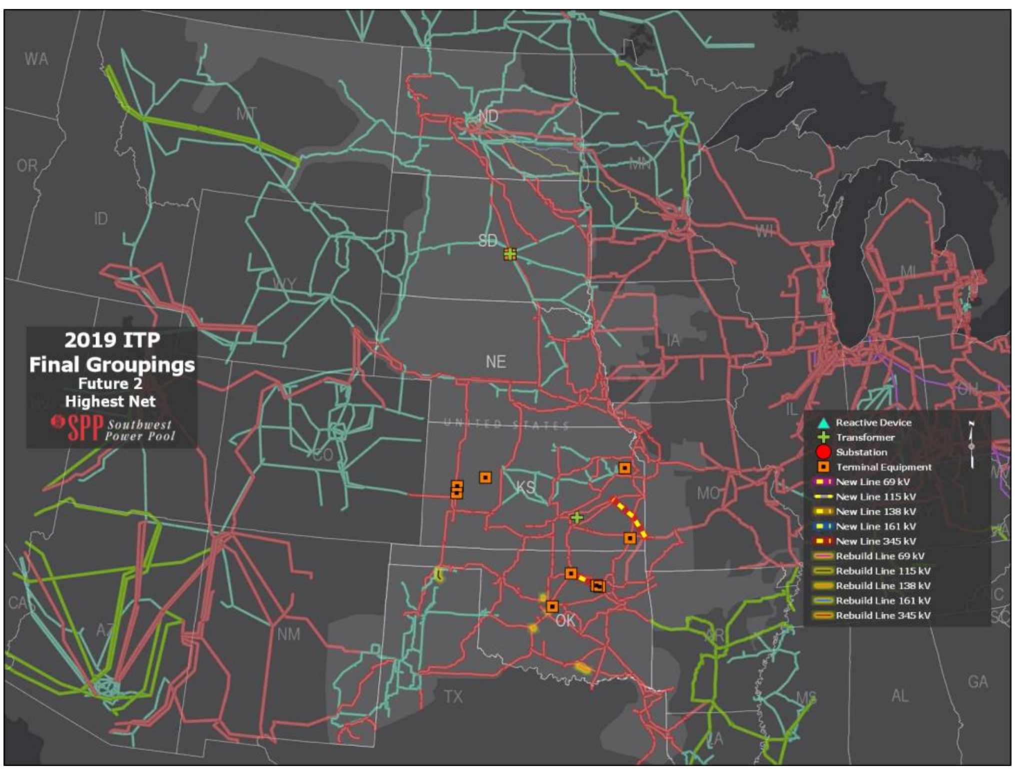


Figure 6.6: Final Groupings - Future 2 - Highest Net APC

Figure 6.7 is a benefit-to-cost comparison (including B/C ratio) of the final groupings. The cost-effective grouping for Future 1 provided a net benefit of $683 million, while the highest net grouping for Future 2 provided $1.891 billion in net benefit. The calculated B/C ratios for each grouping are also shown in the figure.

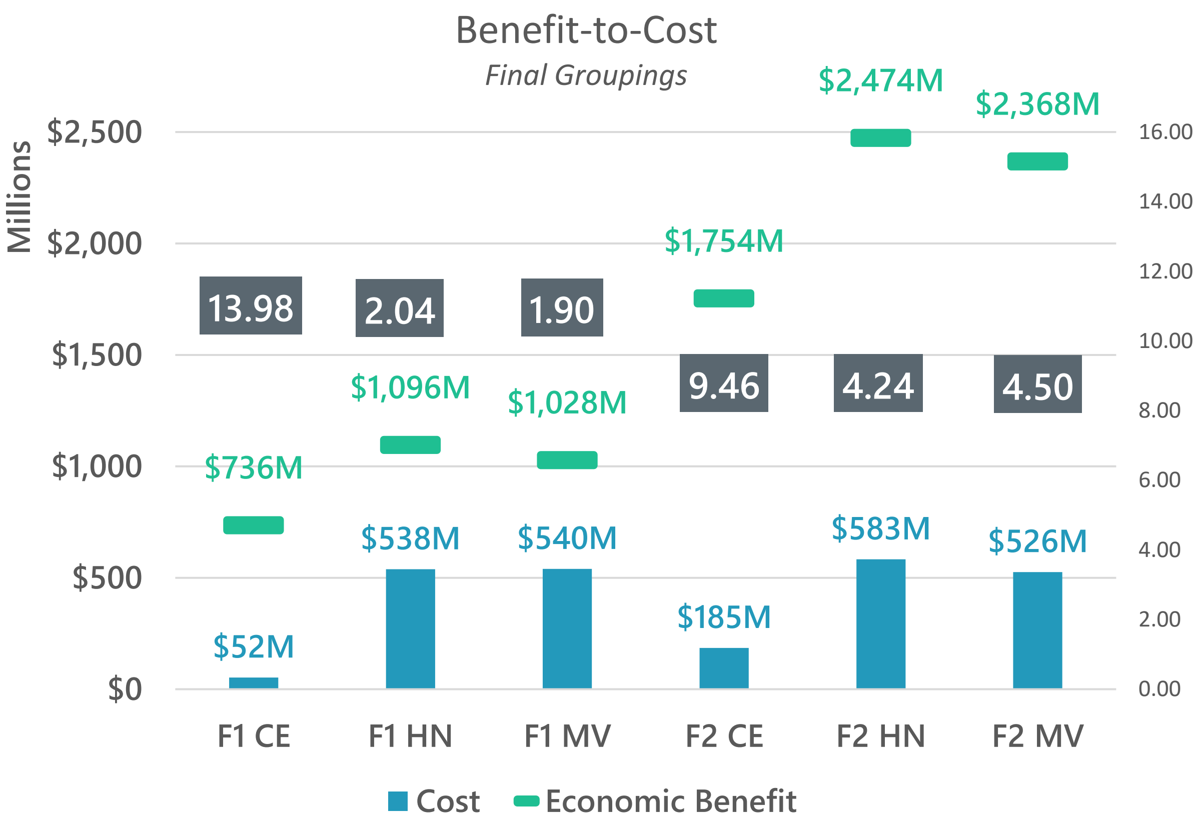


Figure 6.7: Final Groupings – Benefit-to-Cost Comparison

6.3 OPTIMIZATION

The projects included in the reliability groupings were selected based on their ability to be cost-effective, maintain reliability and meet the system's compliance needs. The economic projects were selected for their ability to provide ratepayer benefits from lower-cost energy by mitigating system congestion and improving markets for both buyers and sellers. The project groupings discussed previously were developed based on criteria specific to their need and model type. Reliability groupings specific to each future were evaluated to determine their impact on each economic grouping. Once those comprehensive future specific portfolios were developed, the impact of the base reliability portfolio was assessed. SPP observed overlap between the reliability and economic needs during the needs assessment milestone.

SPP originally identified overlap of reliability and economic needs, specifically in Target Area 1, and included those needs in its posted needs assessment. During the project grouping process the related reliability needs were invalidated due to model corrections. No additional overlap of economic and reliability needs were identified, therefore, all reliability (including those driven by short-circuit needs) and economic projects were included in the final optimized portfolio for each future.

6.4 PORTFOLIO CONSOLIDATION

Stakeholders determined the two futures assessed in the 2019 ITP would be treated equally to determine the consolidated portfolio. When determining whether a project should move forward into the consolidated portfolio, three scenarios could occur:
1) the same project was identified in each future,
2) two projects were competing against each other, or
3) a project was identified in only one future.

Stakeholders determined that if the same project was identified in both futures, that project would move forward into the consolidated portfolio. For the remaining scenarios, an independent method was necessary to assess each project and determine which, or if, those projects should move forward in the process.

To evaluate these scenarios, SPP and its stakeholders developed a comprehensive scoring rubric considering both quantitative and qualitative metrics. Quantitative metrics included APC and the percentage of congestion relieved. Qualitative metrics included giving credit to projects able to address operational congestion or non-thermal issues. Table 6.5 details the scoring rubric as well as some of the minimum criteria projects had to meet to receive points. Staff and stakeholders agreed that although this scoring methodology is a good way to measure a project's effectiveness, it should not be the only input to project selection. Stakeholders and staff agreed a project narrative might be necessary when a preferred project is recommended against the results of the consolidation process.

All short-circuit and reliability projects were included in the consolidated portfolio; therefore, consolidation considerations in this assessment applied to economic projects only. A detailed description of the consolidation methodology and scoring rubric can be found in the 2019 ITP Scope.

No.	Consideration	Possible Points	Project Score
1	40-year (1-year) APC benefit-to-cost ratio in selected future	50	1.0 (0.9)
	40-year (1-year) APC benefit-to-cost ratio in opposite future		0.8 (0.7)
	40-year (1-year) APC net benefit in selected future ($M)		N/A
	40-year (1-year) APC net benefit in opposite future ($M)		N/A
2	Congestion relieved in selected future (by need(s), all years)	10	N/A
	Congestion relieved in opposite future (by need(s), all years)	10	N/A
3	Operational congestion costs or reconfiguration ($M/year or hours/year)	10	>0
4	New EHV	7.5	Y/N
5	Mitigate non-thermal issues	7.5	Y/N
6	Long-term viability (*e.g.*, 2013 ITP20) or improved Auction Revenue Right (ARR) feasibility	5	Y/N
	Total Points Possible	**100**	

Table 6.5: Consolidated Portfolio ScoringConsolidation Scenario One

Four economic projects were included in the Future 1 and Future 2 final portfolios; they were also included in the consolidated portfolio. These projects are:

- Gracemont-Anadarko 138 kV rebuild
- Kingfisher Junction-East Kingfisher Tap 138 kV rebuild
- Spearman-Hansford 115 kV rebuild
- Lawrence Energy Center-Midland 115 kV terminal equipment

6.4.1 CONSOLIDATION SCENARIO TWO

Consolidation Scenario Two occurred when two projects were identified to solve the same or similar economic needs for each future. When this scenario occurred, it was clear a project was needed to address congestion in the models, but the consolidation methodology would be used to identify the better project. For this scenario, the scoring rubric identified in Table 6.5 was used to score the projects and determine which project should move forward into the consolidated portfolio.

6.4.1.1 Target Area 1

The cost-effective grouping in Future 1 included a 345/69 kV transformer at Wolf Creek paired with the phase-shifting transformer at the Butler 138 kV station. The highest net grouping in future two included a new 345 kV line from Wolf Creek-Blackberry, paired with the phase-shifting transformer at the Butler 138 kV station. As shown in Table 6.6, the new 345 kV line from Wolf Creek-Blackberry paired with the phase-shifting transformer at Butler scored higher using the consolidation rubric. The needs solved by these solutions include:

- Wolf Creek 345/69 kV transformer for the loss of Waverly-La Cygne 345 kV
- Butler-Altoona 138 kV for the loss of Caney River-Neosho 345 kV
- Waverly-La Cygne 345 kV for the loss of Caney River/RP2POI10-Neosho 345 kV

No.	Consideration	Possible Points	F1 Project Score	F2 Project Score
1	APC net benefit and benefit-to-cost ratio in selected future APC net benefit and benefit-to-cost ratio in opposite future	50	39.6	50
2	Congestion relieved in selected future (by need(s), all years)	10	19.3	19.9
	Congestion relieved in opposite future (by need(s), all years)	10		
3	Operational congestion costs or reconfiguration ($M/yr or hrs/yr)	10	8	8
4	New EHV	7.5	0	7.5
5	Mitigate non-thermal issues	7.5	0	7.5
6	Long-term viability (*e.g.*, 2013 ITP20) or improved ARR feasibility	5	5	5
	Total Score		**71.9**	**97.9**

Table 6.6: Target Area 1 Consolidation Scoring

6.4.1.2 Target Area 2

The cost-effective grouping for Future 1 included a bus tie upgrade at the Cleveland 138 kV station. The highest net grouping for Future 2 identified a new 345 kV line from Sooner-Wekiwa, paired with terminal equipment on the Sheffield Steel-Sand Springs 138 kV line. As shown in Table 6.7, the Sooner-Wekiwa 345 kV new line paired with the 138 kV terminal equipment scored higher using the consolidation rubric. The needs solved by this project include:

- Cleveland 138 kV bus tie for the loss of Cleveland-Tulsa North 345 kV
- Webb Tap-Osage 138 kV for the loss of Sooner-Cleveland 345 kV

No.	Consideration	Possible Points	F1 Project Score	F2 Project Score
1	APC net benefit and benefit-to-cost ratio in selected future APC net benefit and benefit-to-cost ratio in opposite future	50	48.6	50
2	Congestion relieved in selected future (by need(s), all years)	10	1.3	18
	Congestion relieved in opposite future (by need(s), all years)	10		
3	Operational congestion costs or reconfiguration ($M/yr or hrs/yr)	10	10	10
4	New EHV	7.5	0	7.5
5	Mitigate non-thermal issues	7.5	0	7.5
6	Long-term viability (e.g., 2013 ITP20) or improved ARR feasibility	5	0	0
		Total Score	**59.9**	**93**

Table 6.7: Target Area 1 Consolidation Scoring

6.4.2 CONSOLIDATION SCENARIO THREE

Consolidation Scenario Three occurred when a project was identified in only one of the two final future portfolios. When this situation occurred, the question remained whether a project should ultimately be recommended. For this scenario, the scoring rubric was used as a way to identify if a project should be included in the consolidated portfolio by achieving a minimum score of 70 points. Projects that did not meet the minimum scoring threshold but were recommended to be included have additional qualitative information justifying their inclusion.

<u>Neosho-Riverton 161 kV Rebuild</u>

The Neosho-Riverton 161 kV rebuild was included in the Future 2 portfolio because it addressed some remaining congestion in Target Area 1. The 40-year benefit-to-cost ratio for this project was negative when included incrementally to the Future 1 portfolio, which led to a score of 0 out of a possible 50 points for the net benefit and benefit-to-cost criteria, causing it to score well below the minimum threshold.

No.	Consideration	Possible Points	Project Score
1	APC net benefit and benefit-to-cost ratio in selected future	50	0
	APC net benefit and benefit-to-cost ratio in opposite future		
2	Congestion relieved in selected future (by need(s), all years)	10	20
	Congestion relieved in opposite future (by need(s), all years)	10	
3	Operational congestion costs or reconfiguration ($M/yr or hrs/yr)	10	10
4	New EHV	7.5	0
5	Mitigate non-thermal issues	7.5	0
6	Long-term viability (*e.g.*, 2013 ITP20) or improved ARR feasibility	5	5
		Total Score (minimum 70 threshold)	**35**

Table 6.8: Neosho-Riverton 161 kV Rebuild Consolidation Scoring

<u>Neosho-Caney River 345 kV terminal equipment</u>

The terminal equipment for the Neosho-Caney River 345 kV line were also included in the Future 2 portfolio. The project performed well using the net benefit, benefit-to-cost ratio, and congestion relieved metrics; however, it did not perform well enough with the other considerations to meet the minimum scoring threshold.

No.	Consideration	Possible Points	Project Score
1	APC net benefit and benefit-to-cost ratio in selected future	50	42.6
	APC net benefit and benefit-to-cost ratio in opposite future		
2	Congestion relieved in selected future (by need(s), all years)	10	20
	Congestion relieved in opposite future (by need(s), all years)	10	
3	Operational congestion costs or reconfiguration ($M/yr or hrs/yr)	10	2
4	New EHV	7.5	0
5	Mitigate non-thermal issues	7.5	0
6	Long-term viability (*e.g.*, 2013 ITP20) or improved ARR feasibility	5	0
		Total Score (minimum 70 threshold)	**64.6**

Table 6.9: Neosho-Caney River 345 kV terminal equipment - Scoring

<u>Cimarron-Northwest-Mathewson 345 kV terminal equipment</u>

The project to upgrade terminal equipment on the Cimarron-Northwest-Mathewson 345 kV lines were only included in the Future 2 portfolio. However, it performed well in Future 1, which was why it was included in the initial round of each of the six groupings discussed earlier in this report. The project met the minimum scoring threshold for inclusion in the consolidated portfolio. The ability of this project to address operational congestion on these facilities was the deciding factor for inclusion in the consolidated portfolio.

No.	Consideration	Possible Points	Project Score
1	APC net benefit and benefit-to-cost ratio in selected future	50	45.5
	APC net benefit and benefit-to-cost ratio in opposite future		
2	Congestion relieved in selected future (by need(s), all years)	10	20
	Congestion relieved in opposite future (by need(s), all years)	10	
3	Operational congestion costs or reconfiguration ($M/yr or hrs/yr)	10	8
4	New EHV	7.5	0
5	Mitigate non-thermal issues	7.5	0
6	Long-term viability (*e.g.*, 2013 ITP20) or improved ARR feasibility	5	0
	Total Score (minimum 70 threshold)		**73.5**

Table 6.10: Cimarron-Northwest-Mathewson 345 kV terminal equipment

<u>*South Brown-Russell 138 kV Rebuild*</u>

The South Brown-Russett 138 kV rebuild project was found to have a negative benefit-to-cost ratio in Future 1, which led to the project receiving zero points for the net benefit and benefit-to-cost metric. Because of the low net benefit and benefit-to-cost score, this project did not meet the minimum scoring threshold for inclusion in the consolidated portfolio.

No.	Consideration	Possible Points	Project Score
1	APC net benefit and benefit-to-cost ratio in selected future	50	0
	APC net benefit and benefit-to-cost ratio in opposite future		
2	Congestion relieved in selected future (by need(s), all years)	10	20
	Congestion relieved in opposite future (by need(s), all years)	10	
3	Operational congestion costs or reconfiguration ($M/yr or hrs/yr)	10	2
4	New EHV	7.5	0
5	Mitigate non-thermal issues	7.5	0
6	Long-term viability (*e.g.*, 2013 ITP20) or improved ARR feasibility	5	0
	Total Score (minimum 70 threshold)		**22**

Table 6.11: South Brown-Russell 138 kV Rebuild

<u>*Sundown-Amoco Tap 115 kV terminal equipment*</u>

The Sundown-Amoco Tap 115 kV terminal equipment project was included in the Future 1 portfolio. It received a near perfect score for APC/benefit-to-cost, and congestion relief considerations on the driving needs. Staff recommended the project move forward into the consolidated portfolio, even though it scored just below the minimum threshold, because needs were identified in both Future 1 and Future 2, projected wind modeled in the 2019 ITP is expected to be placed in-service, and continued load growth is expected in the area. Additionally, higher voltage facilities in the area have been issued NTCs, confirming the expected shift of congestion to the lower-voltage system.

No.	Consideration	Possible Points	Project Score
1	APC net benefit and benefit-to-cost ratio in selected future	50	49.4
	APC net benefit and benefit-to-cost ratio in opposite future		
2	Congestion relieved in selected future (by need(s), all years)	10	20
	Congestion relieved in opposite future (by need(s), all years)	10	
3	Operational congestion costs or reconfiguration ($M/yr or hrs/yr)	10	0
4	New EHV	7.5	0
5	Mitigate non-thermal issues	7.5	0
6	Long-term viability (*e.g.*, 2013 ITP20) or improved ARR feasibility	5	0
		Total Score (minimum 70 threshold)	**69.4**

Table 6.12: Sundown-Amoco Tap 115 kV terminal equipment – Scoring

__Arnold-Ransom 115 kV terminal equipment and Pile-Scott City-Setab 115 kV terminal equipment__

Terminal upgrades on these three lines were identified as a cost beneficial project in the Future 2 final portfolio. Although it was not a need in Future 1, when evaluated incrementally with the Future 1 final portfolio, it provided net APC benefits. This led to a perfect score for the net benefit and benefit-to-cost ratio, and congestion-relieved criteria. Additionally, it addresses operational congestion that the system currently experiences, leading to its inclusion in the consolidated portfolio.

No.	Consideration	Possible Points	Project Score
1	APC net benefit and benefit-to-cost ratio in selected future	50	50
	APC net benefit and benefit-to-cost ratio in opposite future		
2	Congestion relieved in selected future (by need(s), all years)	10	20
	Congestion relieved in opposite future (by need(s), all years)	10	
3	Operational congestion costs or reconfiguration ($M/yr or hrs/yr)	10	9
4	New EHV	7.5	0
5	Mitigate non-thermal issues	7.5	0
6	Long-term viability (*e.g.*, 2013 ITP20) or improved ARR feasibility	5	0
		Total Score (minimum 70 threshold)	**79**

Table 6.13: Arnold-Ransom 115 kV terminal equipment and

Pile-Scott City-Setab 115 kV terminal equipment – Scoring

Fort Thompson 230/115 kV Circuit 1 and Two (2) Transformer Replacements

The replacement of the Fort Thompson 230/115 kV transformers was included in the Future 2 final portfolio. When tested in Future 1, these transformer replacements did not meet the benefit-to-cost ratio criteria, resulting in a score of zero for the net benefit and benefit-to-cost ratio scoring criteria. With no points scored in the net benefit and the benefit-to-cost criteria this project did not meet the minimum threshold score and was not included in the consolidated portfolio.

No.	Consideration	Possible Points	Project Score
1	APC net benefit and benefit-to-cost ratio in selected future APC net benefit and benefit-to-cost ratio in opposite future	50	0
2	Congestion relieved in selected future (by need(s), all years)	10	20
	Congestion relieved in opposite future (by need(s), all years)	10	
3	Operational congestion costs or reconfiguration ($M/yr or hrs/yr)	10	2
4	New EHV	7.5	0
5	Mitigate non-thermal issues	7.5	0
6	Long-term viability (*e.g.*, 2013 ITP20) or improved ARR feasibility	5	0
	Total Score (minimum 70 threshold)		**22**

Table 6.14: Fort Thompson 230/115 kV Circuits 1 and 2 Transformer Replacements – Scoring

6.5 FINAL CONSOLIDATED PORTFOLIO

The consolidated portfolio includes the reliability projects addressing both steady state and short-circuit needs, as well as the consolidated set of economic projects that met the consolidation criteria. The consolidated portfolio totals $336.7M and is projected to create over $1B or $2B in APC savings under Future 1 or Future 2 assumptions, respectively. Benefit data reported in this section includes only APC savings.

Project	Classification	Project Cost (2019$)
Pryor Junction 138/115 kV transformer	Reliability	$9,155,167
Tulsa SE-21 St Tap 138 kV rebuild	Reliability	$1,307,802
Tulsa SE-S Hudson 138 kV rebuild	Reliability	$6,724,237
Firth 15 MVAR 115 kV capacitor bank	Reliability	$3,370,000
Cleo Corner-Cleo Junction 69 kV terminal equipment	Reliability	$16,602
Rocky Point-Marietta 69 kV terminal equipment	Reliability	$100,000
Bushland-Deaf Smith 230 kV terminal equipment	Reliability	$1,185,094
Carlisle-LP Doud Tap 115 kV terminal equipment	Reliability	$88,924
Deaf Smith-Plant X 230 kV terminal equipment	Reliability	$1,185,094

Project	Classification	Project Cost (2019$)
Lubbock South-Jones 230 kV circuit 1 terminal equipment	Reliability	$88,924
Lubbock South-Jones 230 kV circuit 2 terminal equipment	Reliability	$88,924
Moore-RB-S&S 115 kV terminal equipment	Reliability	$158,742
Plains Interchange-Yoakum 115 kV terminal equipment	Reliability	$158,742
Potter Co-Newhart 230 kV terminal equipment	Reliability	$1,185,094
Marshall County-Smittyville-Baileyville-South Seneca 115 kV rebuild	Reliability	$17,636,022
Getty East-Skelly 69 kV terminal equipment	Reliability	$114,821
Gypsum 12 MVAR 69 kV capacitor bank	Reliability	$490,093
Replace 21 breakers at Riverside Station 138 kV	Short-Circuit	$16,288,000
Replace 8 breakers at Southwestern Station 138 kV	Short-Circuit	$4,421,345
Replace 1 breaker at Craig 161 kV	Short-Circuit	$254,000
Replace 2 breakers at Leeds 161 kV	Short-Circuit	$440,000
Replace 2 breakers at Midtown 161 kV	Short-Circuit	$440,000
Replace 4 breakers at Southtown 161 kV	Short-Circuit	$880,000
Replace 1 breaker at Moore 13.8 kV tertiary bus	Short-Circuit	$510,000
Replace 2 breakers at Hastings 115 kV	Short-Circuit	$550,000
Replace 5 breakers at Canaday 115 kV	Short-Circuit	$2,600,000
Replace 2 breakers at Westmoore 138 kV	Short-Circuit	$271,289
Replace 3 breakers at Santa Fe 138 kV	Short-Circuit	$406,935
Replace 1 breaker at Carlsbad Interchange 115 kV	Short-Circuit	$552,668
Replace 3 breakers at Denver City North and South 115 kV	Short-Circuit	$5,526,680
Replace 3 breakers at Hale County Interchange 115 kV	Short-Circuit	$1,658,004
Replace 1 breaker at Washita 69 kV	Short-Circuit	$52,400
Replace 12 breakers at Mooreland 138/69 kV	Short-Circuit	$835,850
Replace 3 breakers at Anadarko 138 kV	Short-Circuit	$228,500
Gracemont-Anadarko 138 kV rebuild	Economic	$2,850,000
Kingfisher-East Kingfisher Tap 138 kV rebuild	Economic	$1,000,000
Spearman-Hansford 115 kV rebuild	Economic	$828,359
Lawrence EC-Midland 115 kV terminal equipment	Economic	$30,939
New Wolf Creek-Blackberry 345 kV line and New Butler 138 kV phase-shifting transformer	Economic	$162,649,008
New Sooner-Wekiwa 345 kV line and Sheffield Steel-Sand Springs 138 kV terminal equipment	Economic	$85,948,123
Cimarron-Northwest-Matthewson 345 kV terminal equipment	Economic	$369,869

Project	Classification	Project Cost (2019$)
Arnold-Ransom 115 kV and Pile-Scott City-Setab 115 kV terminal equipment	Economic	$3,652,000
Sundown-Amoco Tap 115 kV terminal equipment	Economic	$358,281
	Total:	**$336,656,532**

Table 6.15: Final Consolidated Portfolio

Table 6.16 shows the Future 1 and Future 2 40-year benefit-to-cost ratio and net benefit of the economic projects included in the consolidated portfolio using the same process described in the Section 6.2.4.1 for project subtraction evaluation.

Project	Project Cost (E&C)	F1 40-year B/C	F1 Net Benefit	F2 40-year B/C	F2 Net Benefit
New Wolf Creek-Blackberry 345 kV line and New Butler 138 kV phase-shifting transformer	$162,409,008	1.33	$88,534,192	2.41	$377,012,612
New Sooner-Wekiwa 345 kV line and Sand Springs-Sheffield Steel 138 kV terminal equipment	$85,948,123	1.12	$16,809,011	4.29	$465,585,456
Cimarron-Northwest-Matthewson 345 kV terminal equipment	$369,869	3.01	$1,226,633	252.87	$153,608,902
Sundown-Amoco Tap 115 kV terminal equipment	$358,281	34.40	$19,730,784	93.65	$54,735,082
Gracemont-Anadarko 138 kV rebuild	$2,850,000	9.42	$39,545,505	27.14	$122,846,721
Kingfisher Jct.-East Kingfisher Tap 138 kV rebuild	$1,000,000	11.98	$18,104,474	26.58	$42,178,550
Arnold-Ransom 115 kV terminal equipment and Pile-Scott City-Setab 115 kV terminal equipment	$3,652,000	0.85	($878,692)	6.72	$34,472,576
Spearman-Hansford 115 kV rebuild	$828,359	23.70	$30,999,476	70.31	$94,673,161
Lawrence-Midland 115 kV terminal equipment	$30,939	2271.70	$115,835,862	4457.64	$227,348,348

Table 6.16: Consolidated Portfolio

Figure 6.8 below shows the benefit-to-cost ratio of the economic portfolio of projects included in the consolidated portfolio. Figure 6.9 shows benefit-to-cost ratio of the entire consolidated portfolio. As expected, the overall benefit-to-cost ratio is reduced within inclusion of the reliability projects, but the consolidated portfolio is still expected to produce benefits well over the cost of the projects.

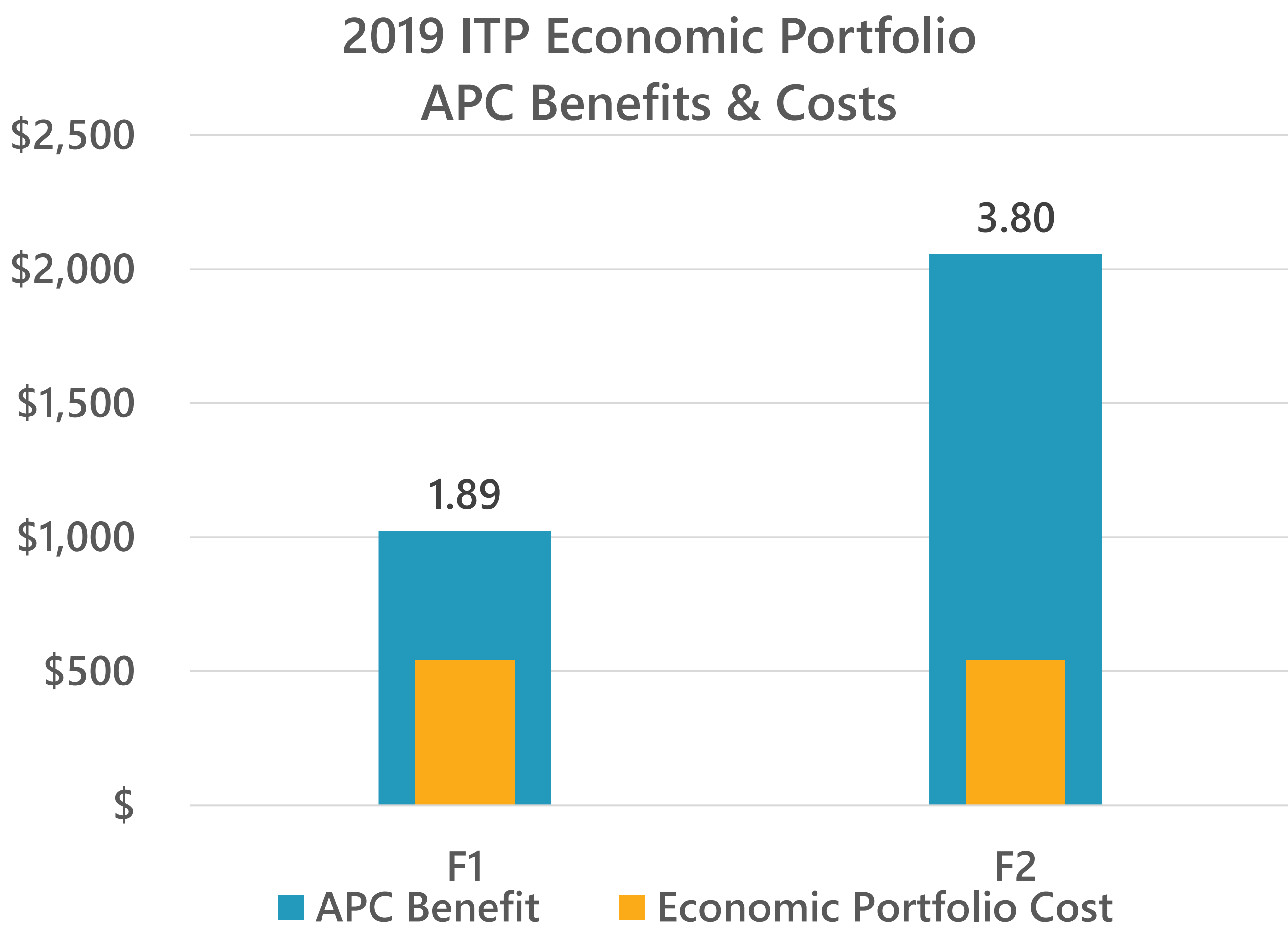


Figure 6.8: Economic Portfolio APC Benefits and Costs

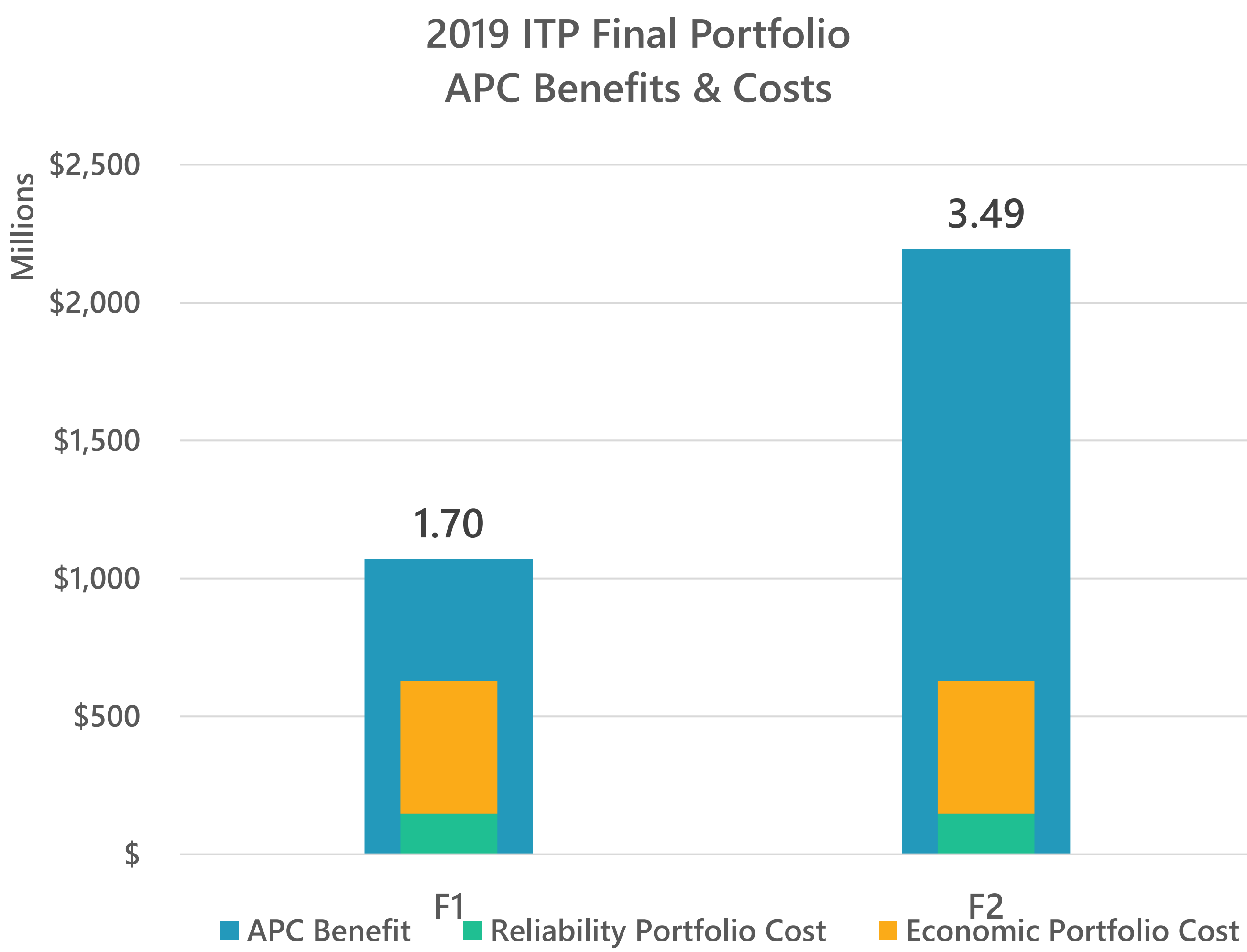


Figure 6.9: Final Consolidated Portfolio APC Benefits and Costs

6.6 STAGING

Staging is the process by which the need date for a project is determined. Unless the need exists in a year two model, an interpolation between model years is performed using different criteria depending on the category of the project. The interpolation methodology can be found in the ITP Manual.

6.6.1 ECONOMIC PROJECTS

The results of staging for the economic projects are shown in the table below.

Project Description	Need Date	Expected Lead Time
Lawrence-Midland 115 kV terminal equipment	1/1/2021	18 months
Sundown-Amoco 115 kV terminal equipment	1/1/2023	18 months

Project Description	Need Date	Expected Lead Time
Spearman-Hansford 115 kV terminal equipment	1/1/2021	18 months
Kingfisher Junction-East Kingfisher Tap 138 kV rebuild	1/1/2021	24 months
Matthewson-Northwest-Cimarron 345 kV terminal equipment	1/1/2021	18 months
New Sooner-Wekiwa 345 kV line and Sheffield-Sand Springs 138 kV terminal equipment	1/1/2026	48 months
Arnold-Ransom and Pile-Scott City-Setab 115 kV terminal equipment	1/1/2025	18 months
Gracemont-Anadarko 138 kV rebuild	1/1/2021	24 months
New Wolf Creek-Blackberry 345 kV line and New Butler 138 kV phase-shifting transformer	1/1/2026	48 months

Table 6.17: Project Staging Results - Economic

6.6.2 POLICY PROJECTS

There were no policy-driven projects in the 2019 ITP.

6.6.3 RELIABILITY PROJECTS

The results of staging for the reliability projects are shown in the table below.

Project Description	Need Date	Expected Lead Time
Cleo Corner-Cleo Switch 69 kV terminal equipment	6/1/2022	18 months
Deaf Smith-Plant X 230 kV terminal equipment	4/1/2029	18 months
Deaf Smith-Bushland 230 kV terminal equipment	4/1/2026	18 months
Potter-Newhart 230 kV terminal equipment	4/1/2028	18 months
Getty-Skelly 69 kV terminal equipment	4/1/2021	18 months
Marshall-Smittyville-Bailey-Seneca 115 kV rebuild	4/1/2021	30 months
Pryor Junction 138/115 kV transformer	6/1/2021	24 months
Tulsa SE-21st Street Tap 138 kV rebuild	6/1/2021	24 months
Tulsa SE-S. Hudson 138 kV rebuild	6/1/2021	24 months
Moore-RBSS 115 kV terminal equipment	6/1/2026	18 months
Carlisle-LP Doud 115 kV terminal equipment	6/1/2026	18 months
Lubbock-Jones 230 kV circuit 1 terminal equipment	6/1/2029	18 months

Project Description	Need Date	Expected Lead Time
Lubbock-Jones 230 kV circuit 2 terminal equipment	6/1/2029	18 months
Plains-Yoakum 115 kV terminal equipment	6/1/2029	18 months
Firth 115 kV capacitor bank	4/1/2021	24 months
Rocky Point-Marietta 69 kV terminal equipment	12/1/2021	18 months
Gypsum 69 kV capacitor bank	6/1/2021	24 months

Table 6.18: Project Staging Results - Reliability

6.6.4 SHORT-CIRCUIT PROJECTS

The short-circuit projects were all staged with a need date of 6/1/2021.

7 PROJECT RECOMMENDATIONS

7.1 TARGET AREA PROJECTS

The ITP Manual Section 4.1.2 describes potential additional analysis of target areas to address specific issues with considerations beyond the scope of a typical ITP assessment. In the 2019 ITP, two areas were identified as potential target areas: southern Kansas/southwest Missouri, and northern Oklahoma.

7.1.1 TARGET AREA 1: SOUTHEAST KANSAS/SOUTHWEST MISSOURI

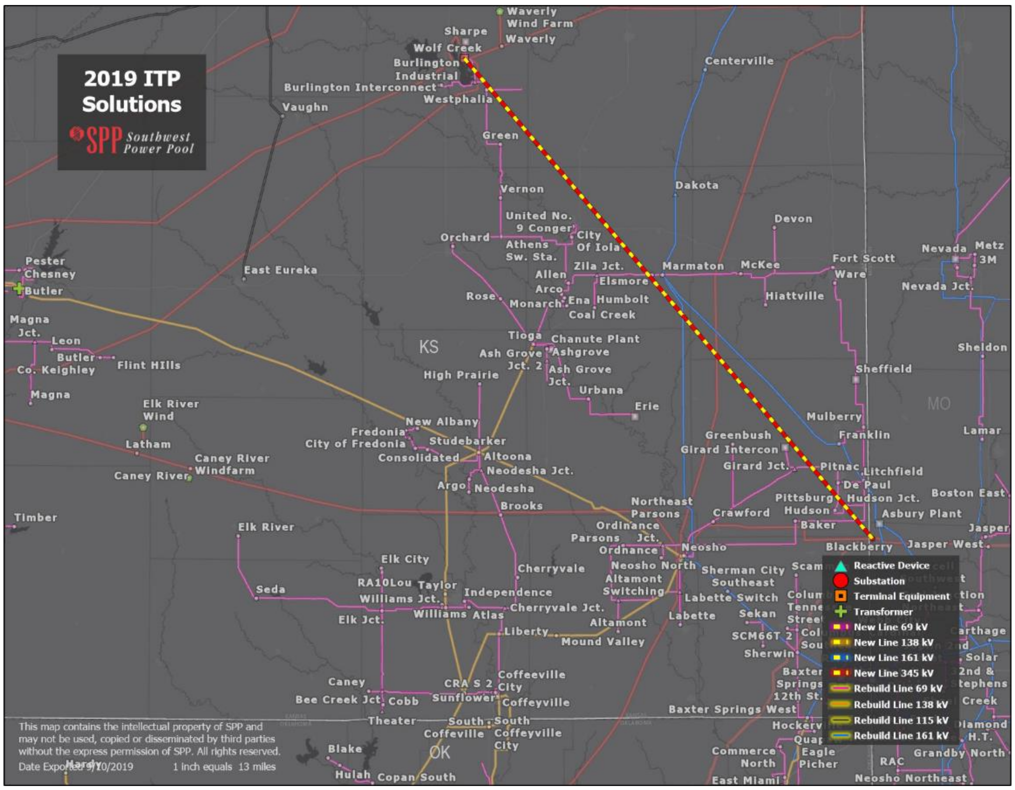


Figure 7.1: New Wolf Creek-Blackberry 345 kV Line and New Butler 138 kV Phase-Shifting Transformer

The new Wolf Creek-Blackberry 345 kV line, paired with the New Butler 138 kV phase-shifting transformer, resolves multiple 2019 ITP needs and additional issues identified for Target Area 1. The major study driver for the new Wolf Creek-Blackberry 345 kV line is its ability to relieve congestion and divert bulk power transfers away from the Wolf Creek-Waverly-La Cygne 345 kV line, Wolf Creek 345/69 kV transformer and downstream 69 kV lines, and allowing system bulk power transfers to continue to flow east to major SPP load centers. This will help to levelize system LMPs, low generator LMPs in the west and high load LMPs in the east, and overall system congestion while providing market efficiencies and benefits to ratepayers and transmission customers.

The new 345 kV line parallels three major contingencies in the area: Caney River-Neosho 345 kV line, Wolf Creek-Waverly-La Cygne 345 kV line, and Neosho-Blackberry 345 kV. Paralleling the Neosho-Blackberry

345 kV line relieves congestion on the Neosho-Riverton 161 kV for the Neosho-Blackberry 345 kV line outage and reduces congestion on Neosho-Riverton 161 kV line for the loss of Blackberry-Jasper 345 kV line outage.

In addition to the projected APC savings, the new Wolf Creek-Blackberry 345 kV line provides multiple reliability benefits. Primarily, it resolves declining transient stability margins at the Wolf Creek nuclear plant by adding a fourth 345 kV outlet that is expected to increase system resiliency and reduce system operation risks. Dynamic simulations show the performance of the Wolf Creek unit with the addition of the Wolf Creek-Blackberry 345 kV transmission line met the "SPP Disturbance Performance Requirements." This solution will address the transient stability limit discussed previously in Section 4.1.1.1.

The Wolf Creek-Blackberry 345 kV line adds transmission capacity that is expected to relieve system loading and increase available transfer capability (ATC) to local long-term transmission service customers. This should also improve positions of candidate ARR holders that would lead to improved TCR funding and reduce the need for counterflow optimization. This line would specifically help to mitigate the Neosho-Riverton 161 kV ARR constraints.

Although the new Wolf Creek-Blackberry 345 kV line is cost beneficial as a standalone project in the 2019 ITP, the new Butler phase-shifting transformer was paired with the 345 kV line to cost effectively mitigate remaining congestion on the Butler-Altoona 138 kV constraint. The congestion relieved by the new Wolf Creek-Blackberry 345 kV line and the new Butler 138 kV phase-shifting transformer is shown in Table 7.1.

The Wolf Creek transformer was identified as a need in the 2018 ITP near-term assessment, but was ultimately not addressed with new construction based upon the TWG's direction to determine a more holistic solution in the 2019 ITP. In addition the Butler-Altoona 138 kV line was loaded just below the SPP Planning Criteria reliability threshold. Continued analysis of reliability needs in the 2019 ITP revealed the Butler-Altoona 138 kV line and Wolf Creek 345/69 kV transformer reliability needs are minimally addressed by model corrections. However, thermal loading on both facilities remained just below the 100% threshold. The Wolf Creek-Blackberry 345 kV line achieves the TWG's goal of addressing thermal loading concerns associated with these facilities.

Alternative solutions were considered and selected in the final Future 1 portfolio – to replace Wolf Creek 345/69 kV transformer and rebuild a portion of the Waverly-La Cygne 345 kV line along with the Butler 138 kV phase-shifting transformer – but they did not perform well together and did not score as well during consolidation of the two futures. Considering that the market economic model represents a DC solution and the issues in the area are due to large power transfers, it is likely that benefits of smaller-scale solutions would not be fully realized due to angular stability limitations and known voltage stability limitations. These smaller-scale solutions could impose operational risks by allowing the system to operate at unstable operating points.[19]

[19] Generally, thermal limitations precede angular and voltage stability limitations of the BES and prevent the system from reaching unstable operating points. When thermal limitations are addressed by smaller-scale solutions that only address the thermal limitation, the thermal limitations may no longer precede angular and voltage stability limitations, and the system may be inadvertently operated at unstable operation points that are less recognizable.

The new Wolf Creek-Blackberry 345 KV line is the preferred alternative to the 2013 ITP 20-year assessment Wolf Creek-Neosho 345 kV line. The Wolf Creek-Blackberry line is considered to be a more diverse project than Wolf Creek-Neosho 345 kV. It performed better from an APC savings perspective, and it provides additional flexibility for future expansion options, including further expansion into eastern load centers and the opportunity for future seams projects with neighboring regions. At approximately 100 miles, it is short enough to not have surge-impedance-loading concerns.

Constraint	Base Congestion Score (k$/MWh)					Consolidated Portfolio Congestion Score (k$/MWh)				
	Future 1			Future 2		Future 1			Future 2	
	2021	2024	2029	2024	2029	2021	2024	2029	2024	2029
Butler-Altoona 138 kV for the loss of Caney River/RP2POI10-Neosho 345 kV	259	435	1,034	704	1,188	1	1	1	4	7
Wolf Creek 345/69 kV transformer for the loss of Waverly-LaCygne 345 kV	19	51	49	85	102	0	0	0	0	0
Neosho-RP2POI10 345 kV for the loss of Waverly-LaCygne 345 kV	0	0	0	47	72	0	0	0	0	0
Neosho-Riverton 161 kV for the loss of Blackberry/RP2POI02-Neosho 345 kV	49	40	30	43	44	0	0	0	0	0
Neosho-Riverton 161 kV for the loss of Blackberry-Jasper 345 kV	0	0	0	0	0	73	94	157	121	218
Waverly-La Cygne 345 kV for the loss of Caney River-Neosho 345 kV	15	20	17	12	7	0	0	0	0	0

Table 7.1: Target Area 1 Congestion Relief

7.1.2 TARGET AREA 2: CENTRAL/SOUTHEAST OKLAHOMA

7.1.2.1 New Sooner-Wekiwa 345 kV Line and Sand Springs-Sheffield Steel 138 kV terminal equipment

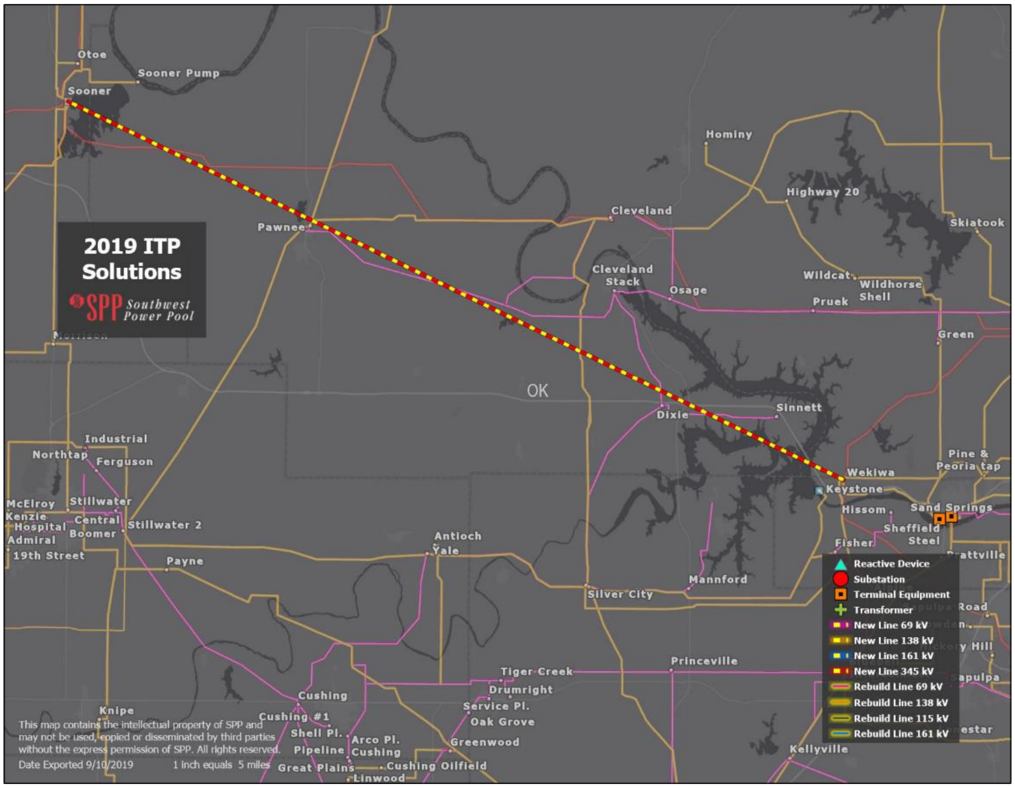


Figure 7.2: New Sooner-Wekiwa 345 kV Line and Sand Springs-Sheffield Steel 138 kV terminal equipment

The new Sooner-Wekiwa 345 kV line, paired with the Sheffield Steel-Sand Springs 138 kV terminal equipment, provides an alternate path for bulk power transfers to continue to flow east to major SPP load centers. This new 345 kV line keeps flows from being diverted to the 138 kV system at Cleveland, where they would continue to flow east toward Tulsa, Oklahoma. The inclusion of the terminal equipment on the 138 kV system in Tulsa is required to achieve the benefit of the EHV line, and it provides additional opportunity for transfers to serve load once the flow is stepped down on the system at the Wekiwa station. The new line parallels two major contingencies in the area: Cleveland-Tulsa North 345 kV line and the Sooner-Cleveland 345 kV line. It provides a new 345 kV source into the west side of Tulsa.

Alternative solutions were considered and ultimately selected in the final Future 1 portfolio – to replace terminal equipment and rebuild multiple sections of 138 kV in the area – but these did not score as well during consolidation of the two futures. Moving forward with these lower kV solutions likely would have driven the need to rebuild/rehabilitate additional 138 kV facilities, increasing overall costs to address congestion. Considering that the market economic model represents a DC solution, and issues in the area are due to large power transfers, it is likely the benefits of smaller-scale solutions would not be fully realized due to voltage stability limitations.

7.1.2.2 Cimarron-Northwest-Matthewson 345 kV terminal equipment

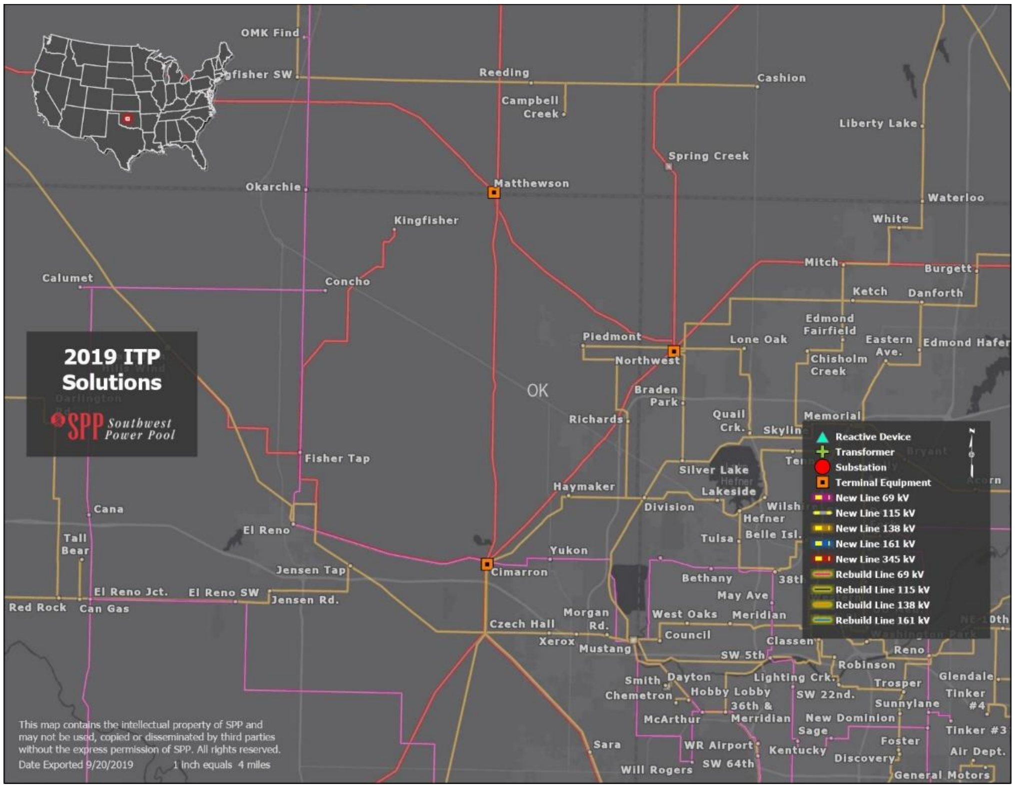


Figure 7.3: Cimarron-Northwest-Mathewson 345 kV terminal equipment

Similar to the Sooner-Wekiwa 345 kV line project, also located in Target Area 2, the Northwest-Mathewson-Cimarron 345 kV line is a thermally-limited path into the Oklahoma City area. Although congestion identified in the needs assessment milestone was only enough to warrant an identified need in Future 2-Year 10, addressing the target area one and Target Area 2 congestion west of Tulsa will create additional flows that move congestion to this area of Oklahoma. The terminal equipment identified for these facilities will continue to allow bulk transfers from the western part of the footprint to eastern load centers.

Constraint	Base Congestion Score (k$/MWh)					Consolidated Portfolio Congestion Score (k$/MWh)				
	Future 1			Future 2		Future 1			Future 2	
	2021	2024	2029	2024	2029	2021	2024	2029	2024	2029
Cleveland AECI-Cleveland GRDA 138 kV for the loss of Cleveland-Tulsa North 345 kV	190	532	383	702	533	0	0	1	5	33
Webb City Tap-Osage 138 kV for the loss of Sooner-Cleveland 345 kV	15	20	17	17	24	0	5	26	54	80
Northwest-Matthewson 345 kV for the loss of Cimarron-Northwest 345 kV	0	7	36	9	90	0	0	0	0	0

Table 7.2: Target Area 2 Congestion Relief

7.2 RELIABILITY PROJECTS

7.2.1 PRYOR JUNCTION 138/115 KV TRANSFORMER

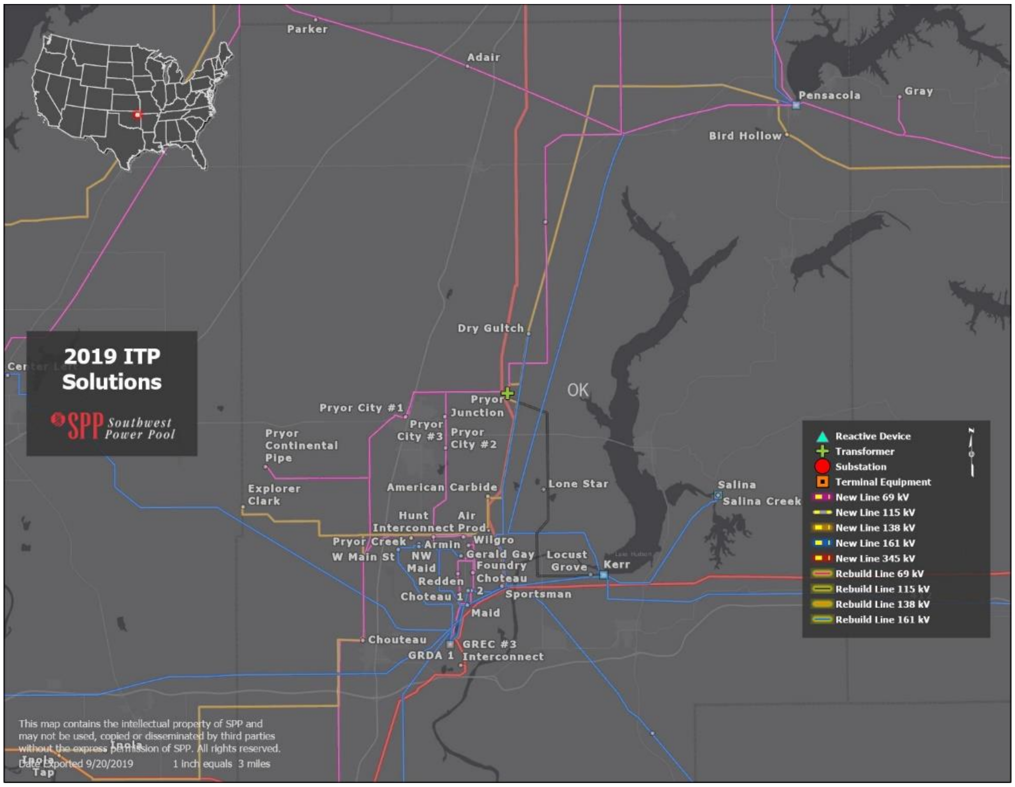


Figure 7.4: Pryor Junction 138/115 kV Transformer

East of Tulsa, near the town of Pryor, Oklahoma, the Pryor Junction 115/69 kV transformer overloads for the loss of the Inola Tap-Catoosa 138 kV line. Loss of this feed to west of Pryor increases flows from the 115 kV source in the east. These flows currently step down to the 69 kV bus at Pryor Junction and back up to the 138 kV bus at Pryor Junction to serve load on the 138 kV system that is no longer served from the western source. The project selected to mitigate this issue is to replace the 115/69 kV transformer with a 138/115 kV transformer to tie the 115 kV and 138 kV systems together and bypass the step-down to the 69 kV system.

7.2.2 TULSA SOUTHEAST-21ST ST. TAP 138 KV REBUILD

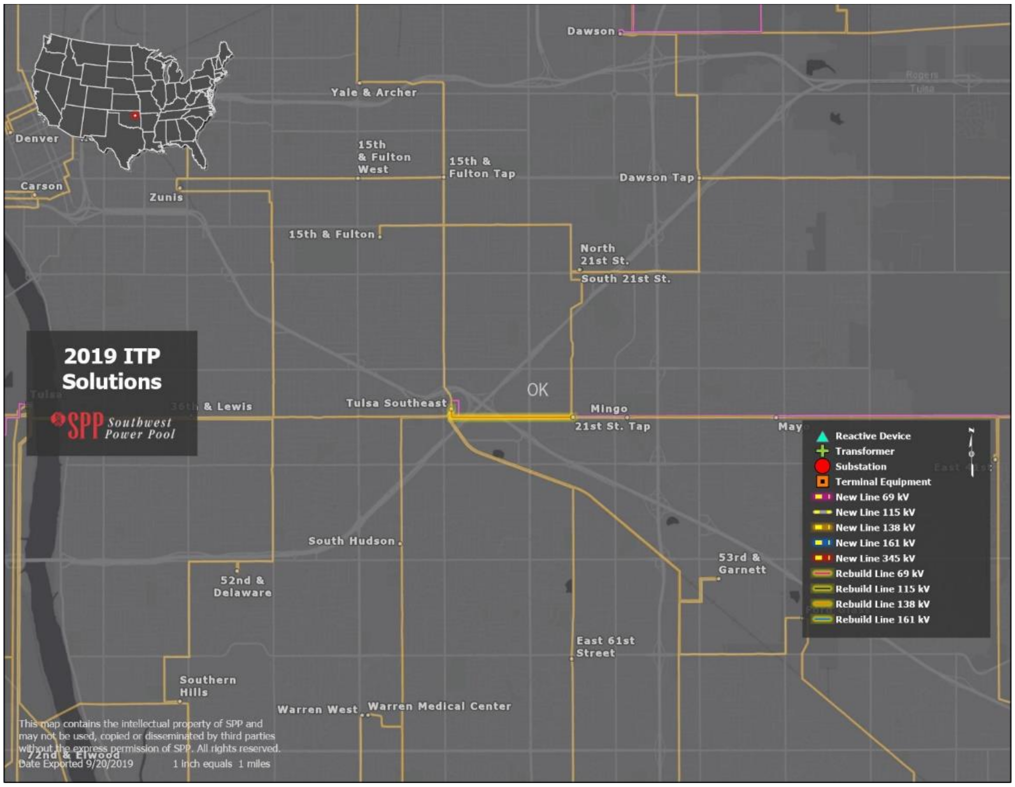


Figure 7.5: Tulsa Southeast-21st St. Tap 138 kV Rebuild

Southeast of downtown Tulsa, Oklahoma, the Tulsa Southeast-21st Street Tap 138 kV line overloads for the loss of the Broken Arrow North-Oneta 138 kV line. When the source from the Oneta generating plant on the east side of Tulsa is lost, west to east flows increase due to the loss of counterflows. The project selected to mitigate this issue is to rebuild the Tulsa Southeast-21st Street Tap 138 kV line to improve the rating closer to SPP minimum design guidelines.

7.2.3 TULSA SE-S. HUDSON 138 KV REBUILD

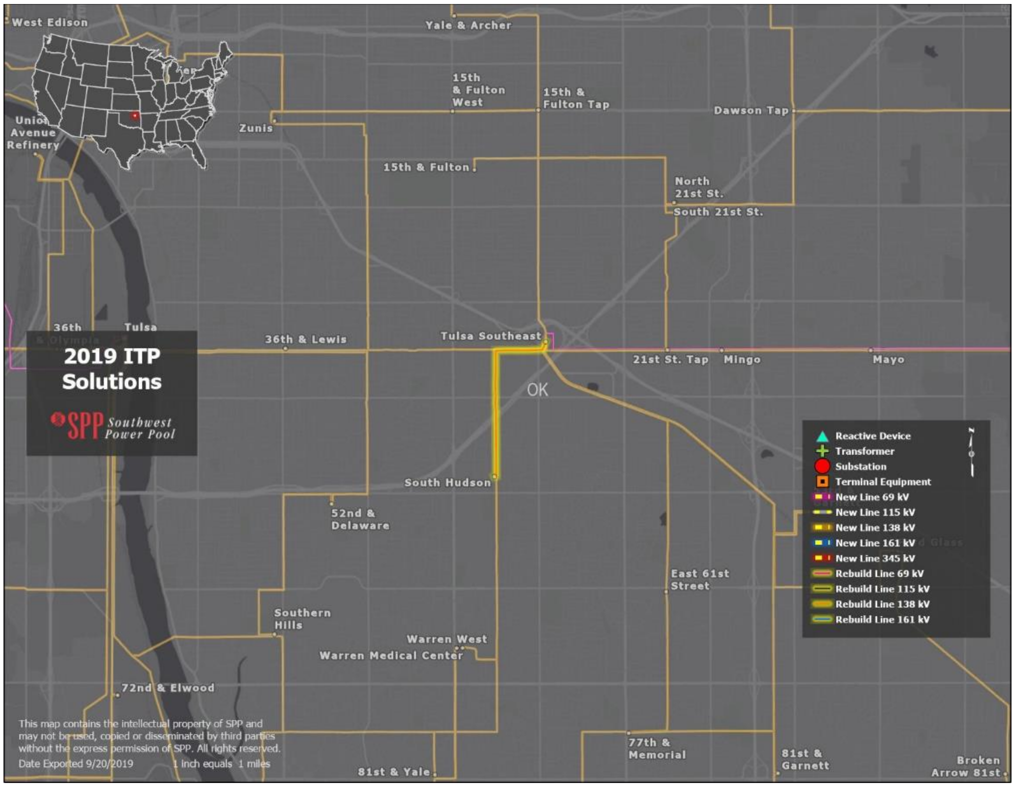


Figure 7.6: Tulsa Southeast-South Hudson 138 kV Rebuild

Southeast of downtown Tulsa, Oklahoma, the Tulsa Southeast-South Hudson 138 kV line overloads for the loss of the Riverside Station-Oral Roberts University (ORU) Tap 138 kV line. When one of the sources from the Riverside Station generating plant to the south is lost, north-to-south flows increase to serve load south of the Tulsa Southeast substation. The project selected to mitigate this issue is to rebuild the Tulsa Southeast-South Hudson 138 kV line to improve the rating closer to SPP minimum design guidelines.

7.2.4 CLEO CORNER-CLEO JUNCTION 69 KV TERMINAL EQUIPMENT

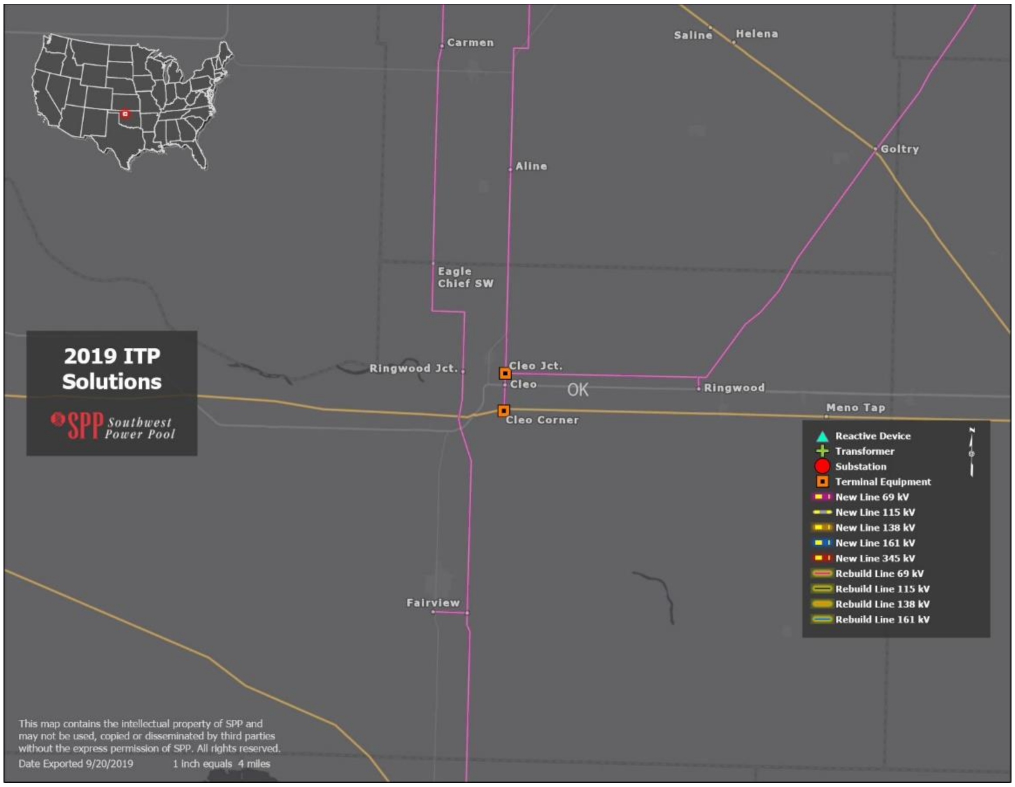


Figure 7.7: Cleo Corner-Cleo Junction 69 kV terminal equipment

In north-central Oklahoma, east of Enid, the Cleo Corner-Cleo Junction 69 kV line overloads for the loss of the 138 kV line connecting the OGE and Western Farmers' Renfrow substations. Losing this northern 138 kV source to the 69 kV system in the area forces more flow from the 138 kV system to step down at Cleo Corner, overloading the 69 kV line. The project selected to mitigate this issue is to replace any necessary terminal equipment at Cleo Corner and Cleo Junction to increase the line rating.

7.2.5 ROCKY POINT-MARIETTA 69 KV TERMINAL EQUIPMENT

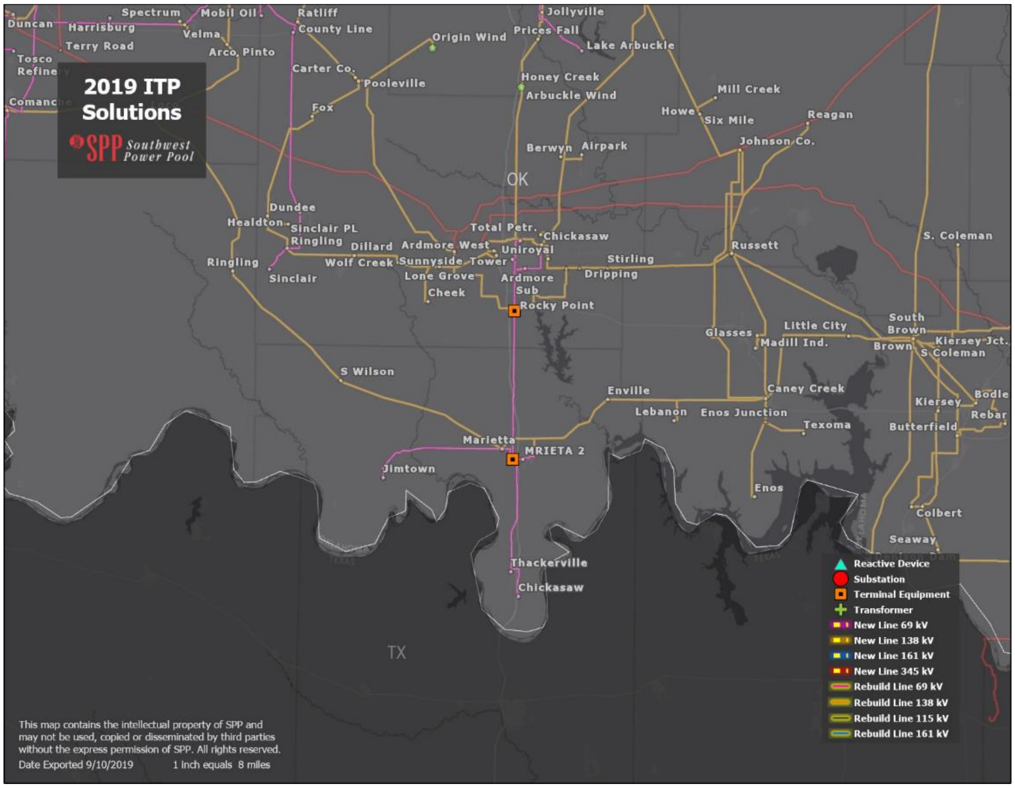


Figure 7.8: Rocky Point-Marietta 69 kV terminal equipment

In south-central Oklahoma near Marietta, the 138 kV system experiences low voltage for loss of the Caney Creek-Texoma Junction 138 kV line. This contingency creates a long radial system that serves nearly 100 MW of load at peak intervals. A capacitor bank at the Lebanon 138 kV station was analyzed and found to provide minimal voltage support. It was determined that a new source was needed to sufficiently raise voltage in the area. SPP analyzed multiple different 138 kV sources and, working with incumbent TOs, found the most cost-effective solution for the region was to close in an existing 69 kV line between OGE's Rocky Point substation and a switch near Marietta. The project selected to mitigate this issue is to install relay protection equipment to operate the existing line as a networked facility.

7.2.6 FIRTH 115 KV CAPACITOR BANK AND SUBSTATION EXPANSION

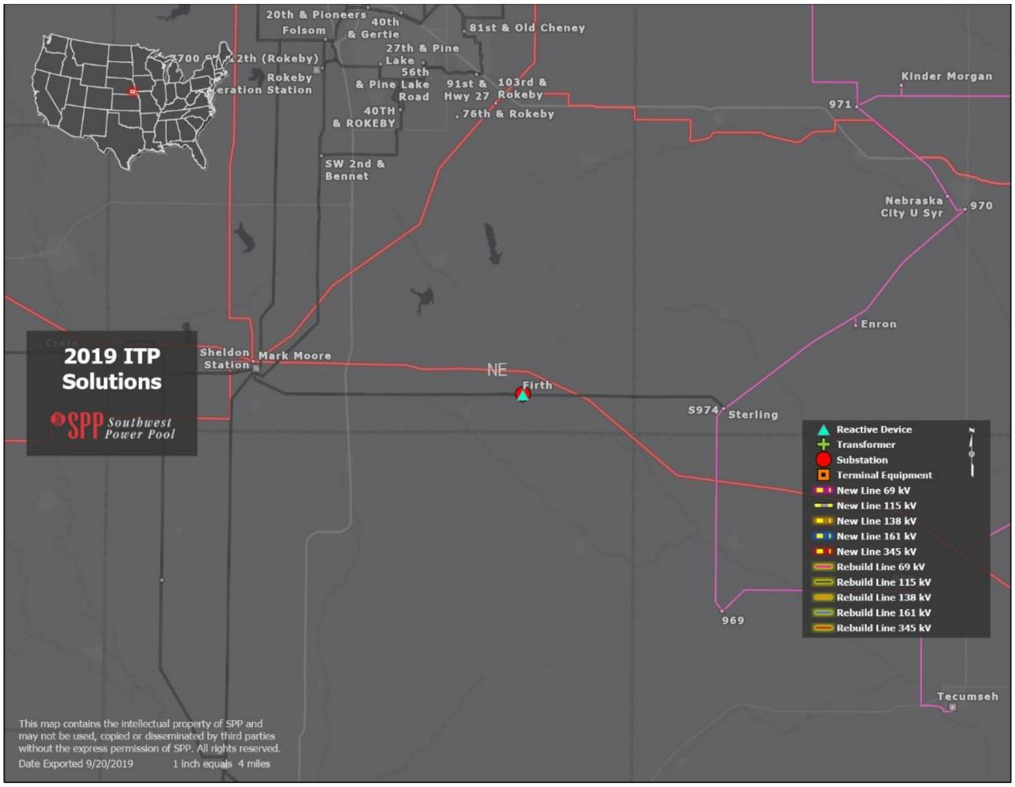


Figure 7.9: Firth 115 kV Capacitor Bank and Substation Expansion

SPP has persistently identified low-voltage issues on the 115 kV and 69 kV transmission system around the Firth and Sterling substations just south of Lincoln, Nebraska, during the summer, winter, as well as light load base reliability models. There was in increase in load at Firth, which decreases voltage below the acceptable range and makes the voltage unable to be mitigated through adjustments of transformer tap ratios. The same low-voltage issues were present in the 2018 ITPNT, but were able to be mitigated through reactive settings. The 15 MVAR capacitor bank, which will require substation expansion, proposed to address the low voltage was coordinated with Nebraska Public Power District and agreements on feasibility have been reached.

7.2.7 BUSHLAND-DEAF SMITH 230 KV TERMINAL EQUIPMENT

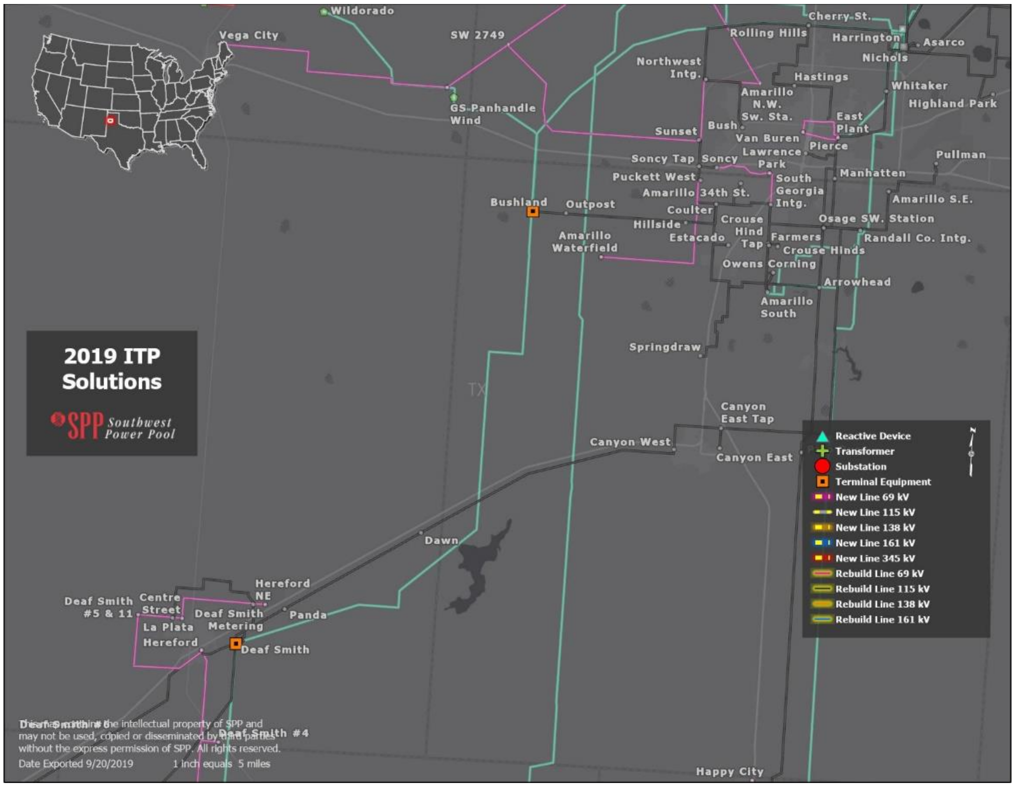


Figure 7.10: Bushland-Deaf Smith 230 kV terminal equipment

In the Texas Panhandle, east of Amarillo, the Bushland-Deaf Smith 230 kV line overloads for loss of the parallel Potter-Newhart 230 kV line. This line is part of a larger 230 kV corridor that aids in transferring power to the southern SPS load pockets. This corridor is heavily used in lighter load conditions when generation to the south is displaced by higher wind output levels. This transfer increases in the year-10 horizon, when additional generation to the south is decommitted due to projected retirements, causing the 230 kV line to overload. The project selected to mitigate this issue is to replace any necessary terminal equipment at Bushland and Deaf Smith to increase the line rating.

7.2.8 CARLISLE-LP DOUD TAP 115 KV TERMINAL EQUIPMENT

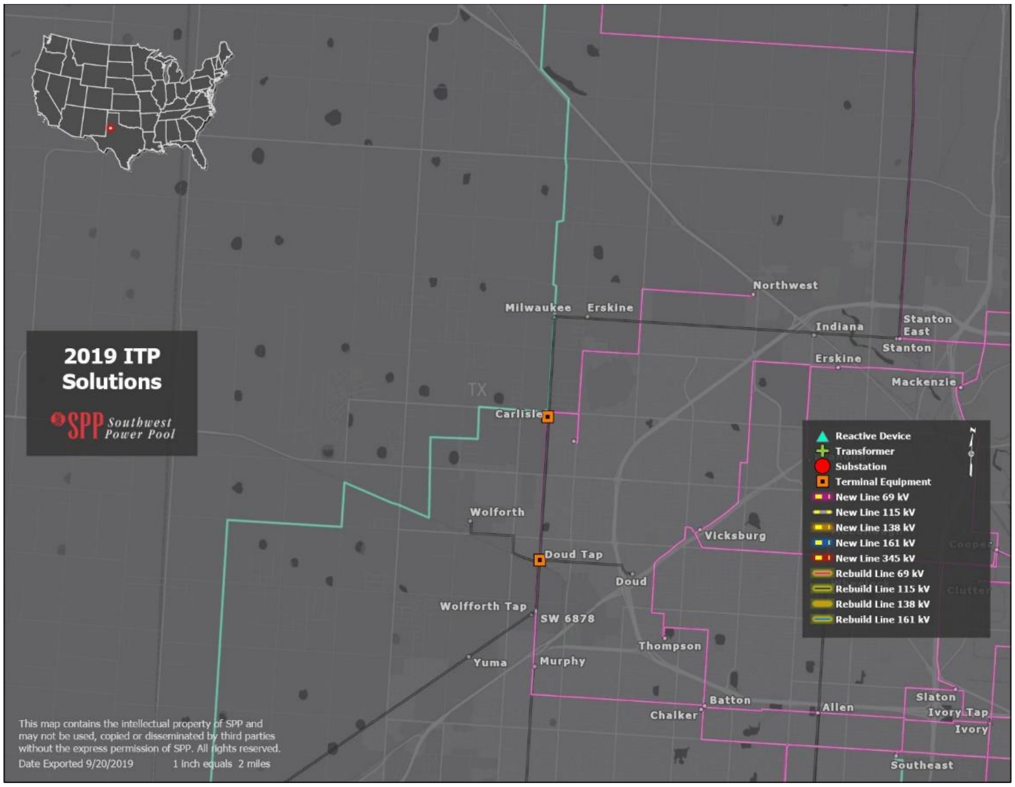


Figure 7.11: Carlisle-LP Doud Tap 115 kV terminal equipment

In the Texas Panhandle, east of Lubbock, the Carlisle-LP Doud Tap 115 kV line overloads for loss of the Wolfforth 230/115 kV transformer. The 230 kV system surrounding Lubbock is an off-ramp to serve load on the lower voltage system and part of the north-to-south highway for load pockets in the south SPS zone, which is continued by the 115 kV system to the southwest from the Wolfforth substation. When the Wolfforth transformer is lost, the counterflow provided on the 115 kV system to the north from Wolfforth into the city is lost. The flows in the area are aggravated by projected generator retirements southeast of Lubbock in the year-10 horizon, causing the line to overload. Due to the projected move of a portion of Lubbock load to the ERCOT system, a sensitivity was performed to remove the load and redispatch generation accordingly. The sensitivity showed that the thermal loading increased. This is consistent with the issues identified in SPP's Attachment AQ study. The project selected to mitigate this issue is to replace any necessary terminal equipment at Carlisle and LP Doud to increase the line rating.

7.2.9 DEAF SMITH-PLANT X 230 KV TERMINAL EQUIPMENT

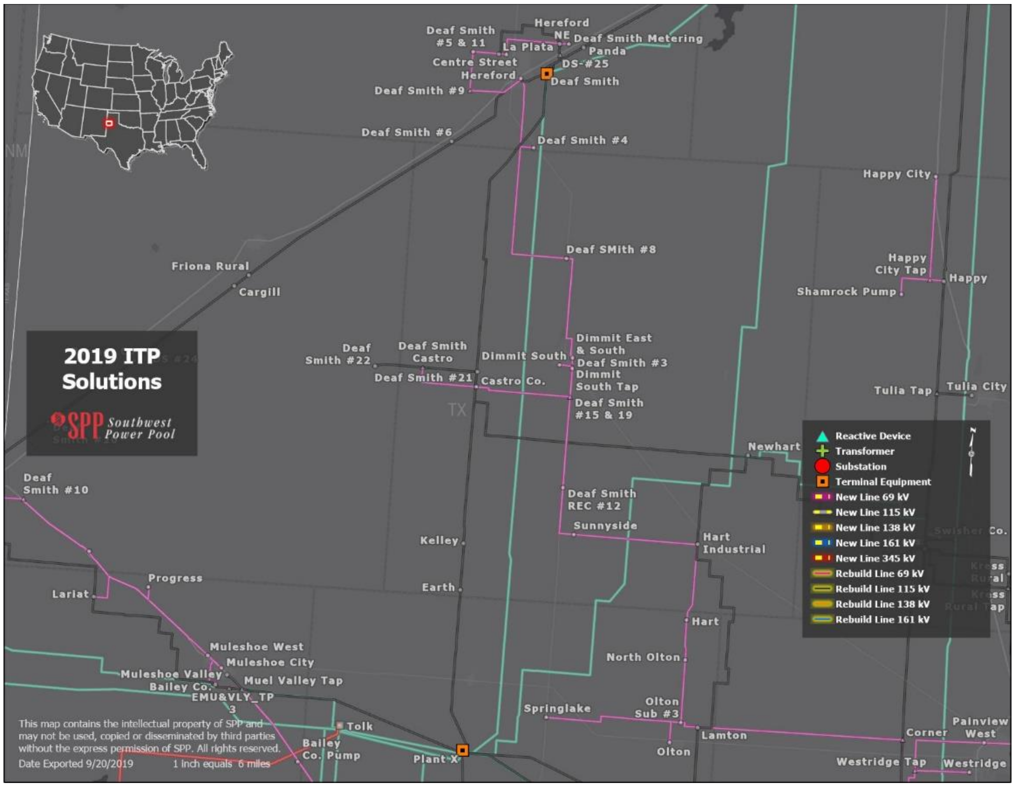


Figure 7.12: Deaf Smith-Plant X 230 kV terminal equipment

In the Texas Panhandle, east of Amarillo, the Deaf Smith-Plant X 230 kV line overloads for loss of the parallel Potter-Newhart 230 kV line. This line is part of a larger 230 kV corridor that aids in transferring power to the southern SPS load pockets. This corridor is heavily used in lighter load conditions when generation to the south is displaced by higher wind output levels. This transfer increases in the 10-year horizon when additional generation to the south is de-committed due to projected retirements, causing the 230 kV line to overload. The project selected to mitigate this issue is to replace any necessary terminal equipment at Deaf Smith and Plant X to increase the line rating.

7.2.10 LUBBOCK SOUTH-JONES 230 KV TERMINAL EQUIPMENT CIRCUITS 1 AND 2

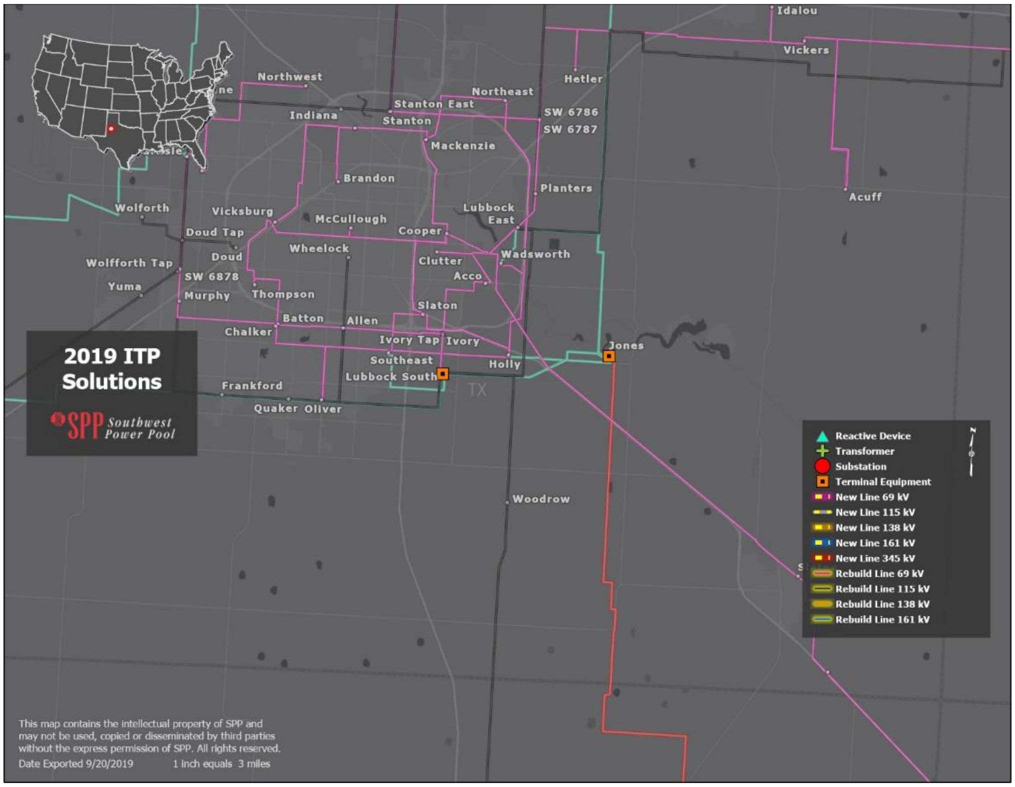


Figure 7.13: Lubbock South-Jones 230 kV terminal equipment Circuits 1 and 2

In the Texas Panhandle, southwest of Lubbock, both of the Lubbock South-Jones 230 kV lines overload for the loss of each other. The 230 kV system surrounding the city of Lubbock is an off-ramp to serve load on the lower voltage system and part of the north-to-south highway for load pockets in the south SPS zone. Flows in the area are aggravated by projected generator retirements southeast of Lubbock in the 10-year horizon, causing the line to overload. Due to the projected move of a portion of Lubbock load to the ERCOT system, a sensitivity was performed to remove the load and redispatch generation accordingly. The sensitivity showed that the thermal loading increased on these facilities. The projects selected to mitigate these issues are to replace any necessary terminal equipment at Lubbock South and Jones to increase the line rating.

7.2.11 MOORE-RB-S&S 115 KV TERMINAL EQUIPMENT

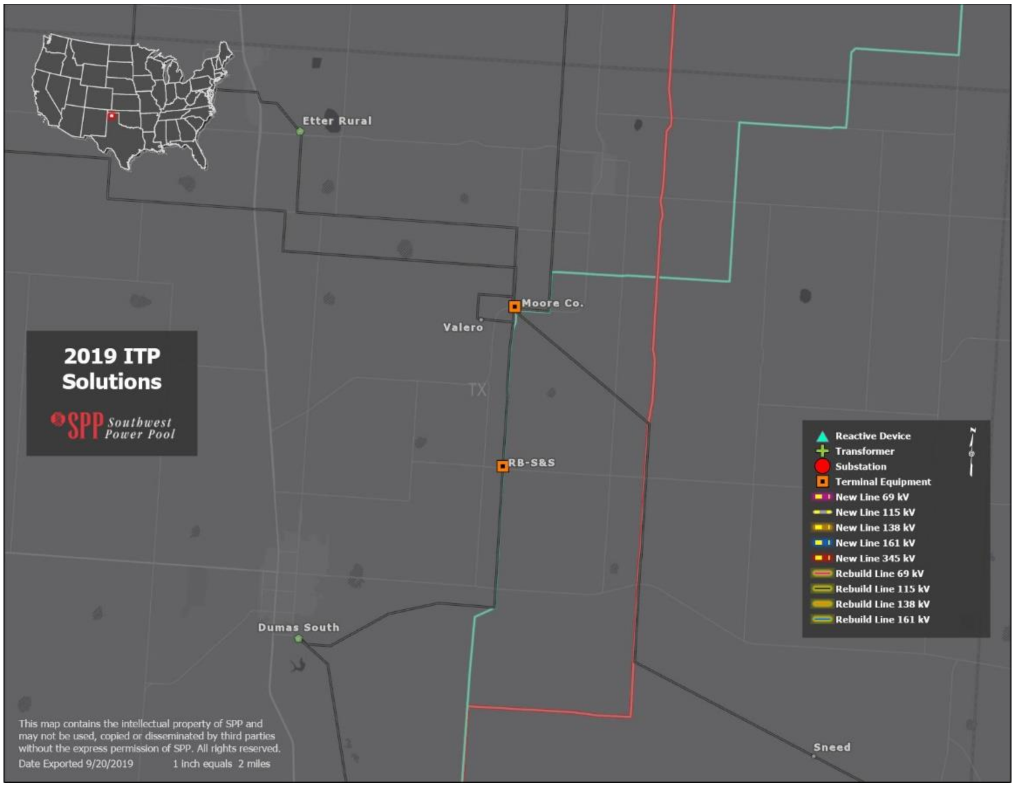


Figure 7.14: Moore-RB-S&S 115 kV terminal equipment

In the Texas Panhandle north of Amarillo, the Moore-RB-S&S (Rita Blanca's Stokes and Sheldon) 115 kV line overloads for loss of the McDowell-Exell Tap 115 kV line. The outage creates a radial 115 kV circuit out of the Moore substation that serves about 80 MW of load during peak conditions in the 10-year horizon. The Moore-RB-S&S segment is the lowest-rated section of the radial under contingent conditions. A large portion of the load is served at the RB-S&S substation, reducing flows on the rest of the line segments. The project selected to mitigate this issue is to replace any necessary terminal equipment at Moore and RB-S&S to increase the line rating.

7.2.12 PLAINS INTERCHANGE-YOAKUM 115 KV TERMINAL EQUIPMENT

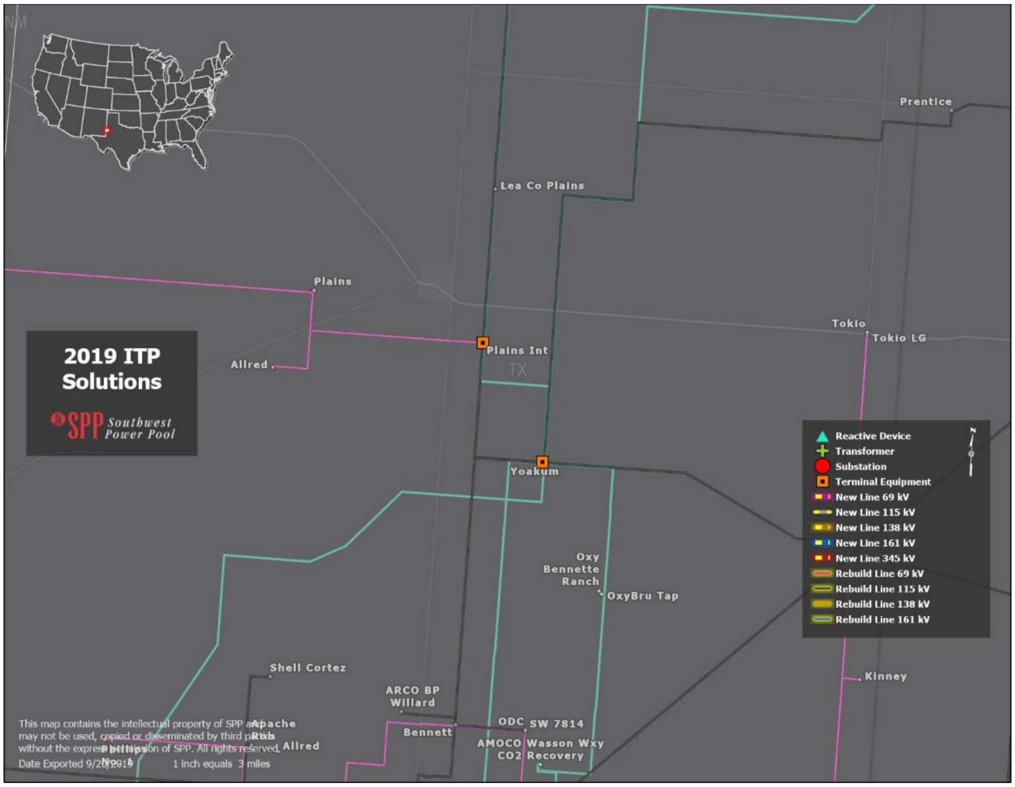


Figure 7.15: Plains Interchange-Yoakum 115 kV terminal equipment

In the Texas Panhandle, nearly equidistant between Levelland and Hobbs, the Plains Interchange-Yoakum 115 kV line overloads for loss of the Pacific-Sundown 115 kV line. When Pacific-Sundown is outaged, the source to the west side of the 115 kV system in the area is lost, forcing flows to increase to the east and loop back around to serve load on the west side. A previously-approved SPP project, Dean Interchange, tied the 230 and 115 kV systems together just north of Plains Interchange. This project would have provided an additional source to the area, but it was withdrawn in the 2018 ITPNT as not needed. This assessment confirms the decision to withdraw the project, as the issue was identified only in year 10 and can be resolved with a more cost-effective solution. The project selected to mitigate this issue is to replace any necessary terminal equipment at Plains Interchange and Yoakum to increase the line rating.

7.2.13 POTTER COUNTY-NEWHART 230 KV TERMINAL EQUIPMENT

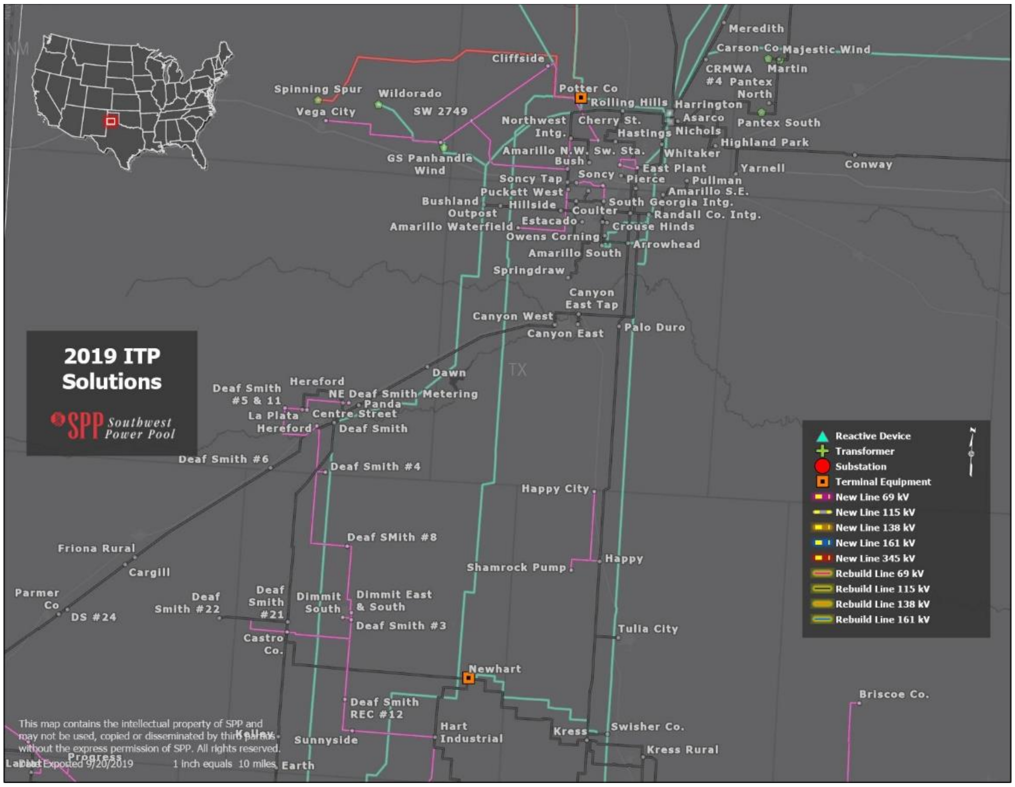


Figure 7.16: Potter County-Newhart 230 kV terminal equipment

In the Texas Panhandle east of Amarillo, the Potter County-Newhart 230 kV line overloads for loss of the parallel Bushland-Deaf Smith 230 kV line. This line is part of a larger 230 kV corridor that aids in transferring power to the southern SPS load pockets. This corridor is heavily used in lighter load conditions when generation to the south is displaced by higher wind output levels. This transfer increases in the 10-year horizon when additional generation to the south is decommitted due to projected retirements, causing the 230 kV line to overload. The project selected to mitigate this issue is to replace any necessary terminal equipment at Potter County and Newhart to increase the line rating.

7.2.14 GYPSUM 69 KV CAPACITOR BANK

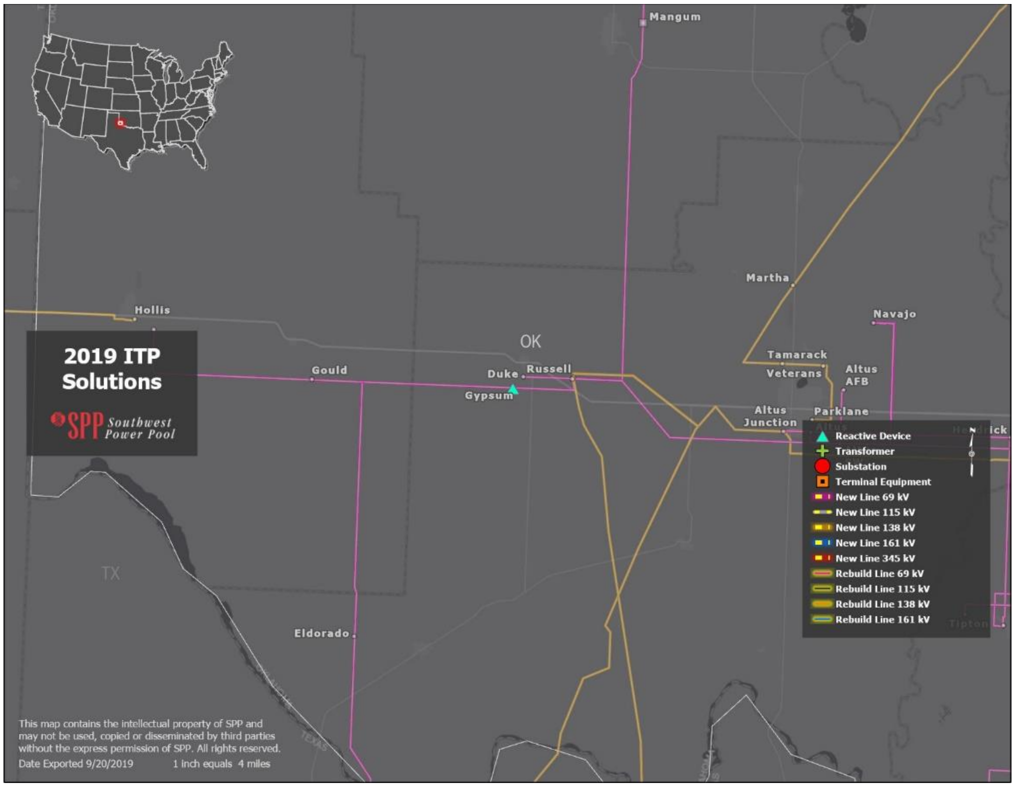


Figure 7.17: Gypsum 69 kV Capacitor Bank

In the southwest corner of Oklahoma, west of Altus near the Texas border, the 69 kV system out of Lake Pauline experiences low voltage for loss of the Duke-Russell 69 kV line. This outage creates a radial system from the Lake Pauline substation in Texas. The project selected to mitigate this issue is to install a 12 MVAR capacitor bank at Gypsum 69 kV.

7.2.15 MARSHALL COUNTY-SMITTYVILLE-BAILEYVILLE-SOUTH SENECA 115 KV REBUILD

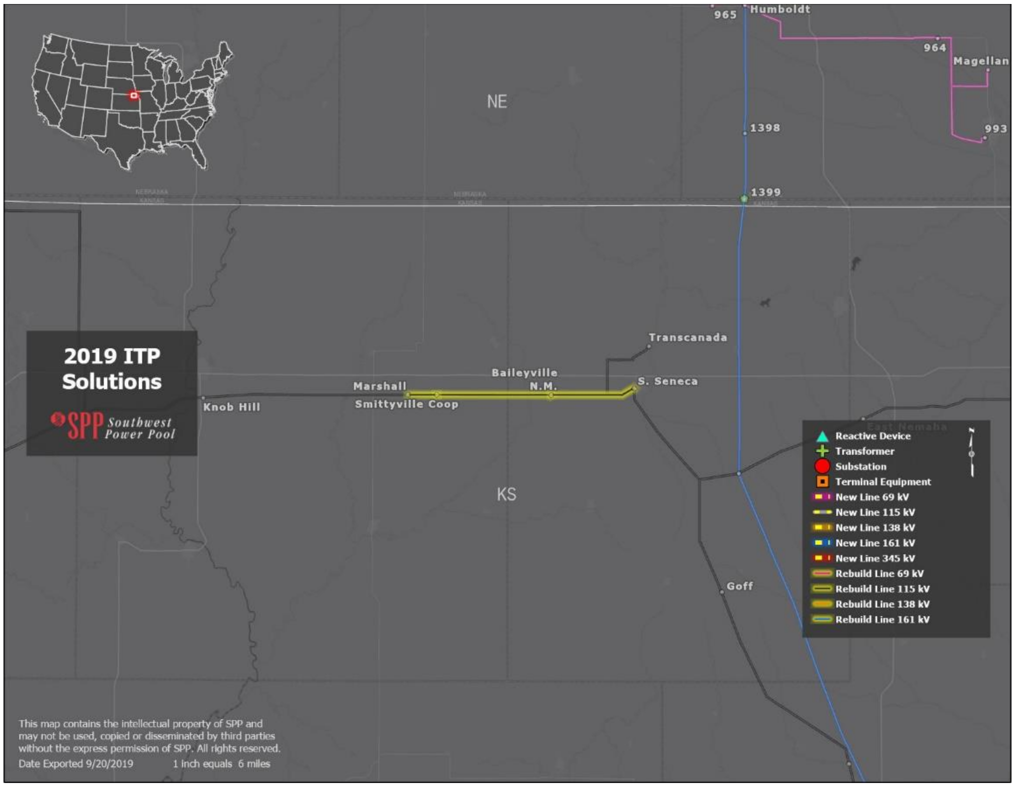


Figure 7.18: Marshall County-Smittyville-Baileyville-South Seneca 115 kV Rebuild

The 115 kV line sections between Marshall County and South Seneca in northeast Kansas overloads for loss of the Harbine-Steel City 115 kV line to the northwest. Losing this line directs the flow from the Steele Flats wind farm south. Incremental load increases between the previous ITP assessment models and the 2019 ITP models, contributing to the resulting overloads. The line is significantly below the nearby line ratings. The project selected to mitigate these overloads is to rebuild these sections of line.

7.2.16 GETTY-SKELLY 69 KV TERMINAL EQUIPMENT

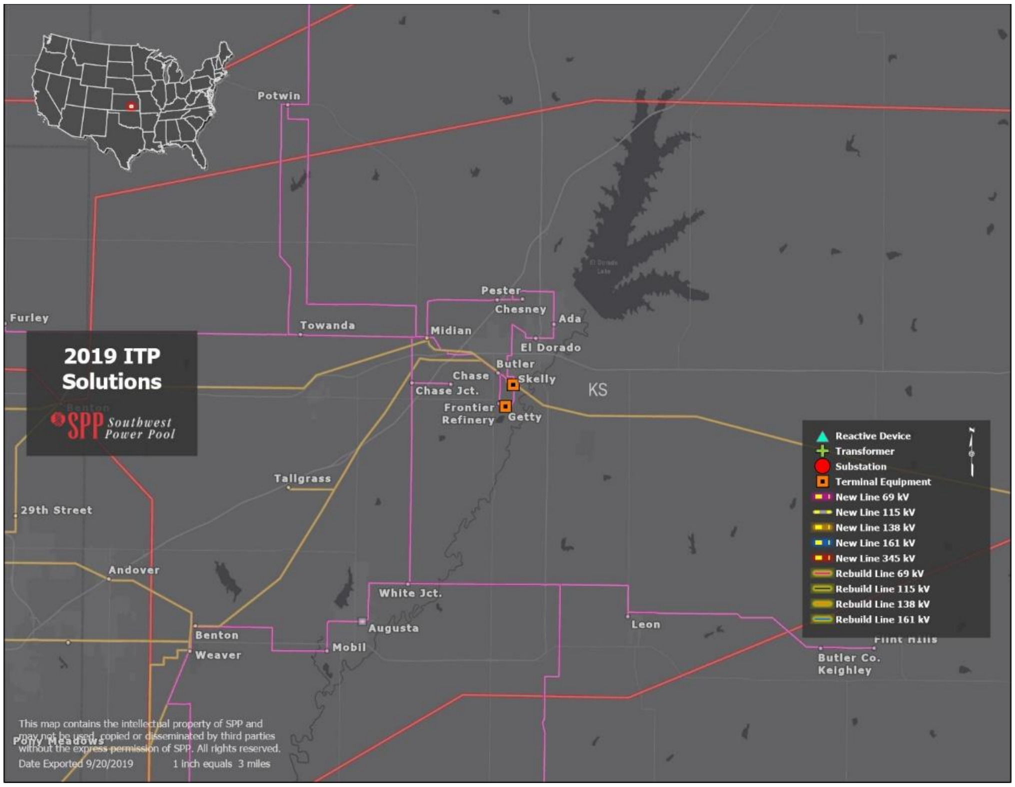


Figure 7.19: Getty-Skelly 69 kV terminal equipment

The Getty-Skelly 69 kV line is the eastern side of a loop serving the Frontier refinery. Losing the western side of the loop, Butler-Frontier 69 kV, radializes the refinery and causes the Getty-Skelly line to overload, as it serves the refinery's entire load. This line was loaded at 99% in previous studies for the same contingency. Minor load increases at the refinery caused the overload in the current models. The project recommended to address this issue is to replace any terminal equipment necessary to increase the line rating.

7.3 SHORT-CIRCUIT PROJECTS

7.3.1 SHORT-CIRCUIT PROJECT PORTFOLIO

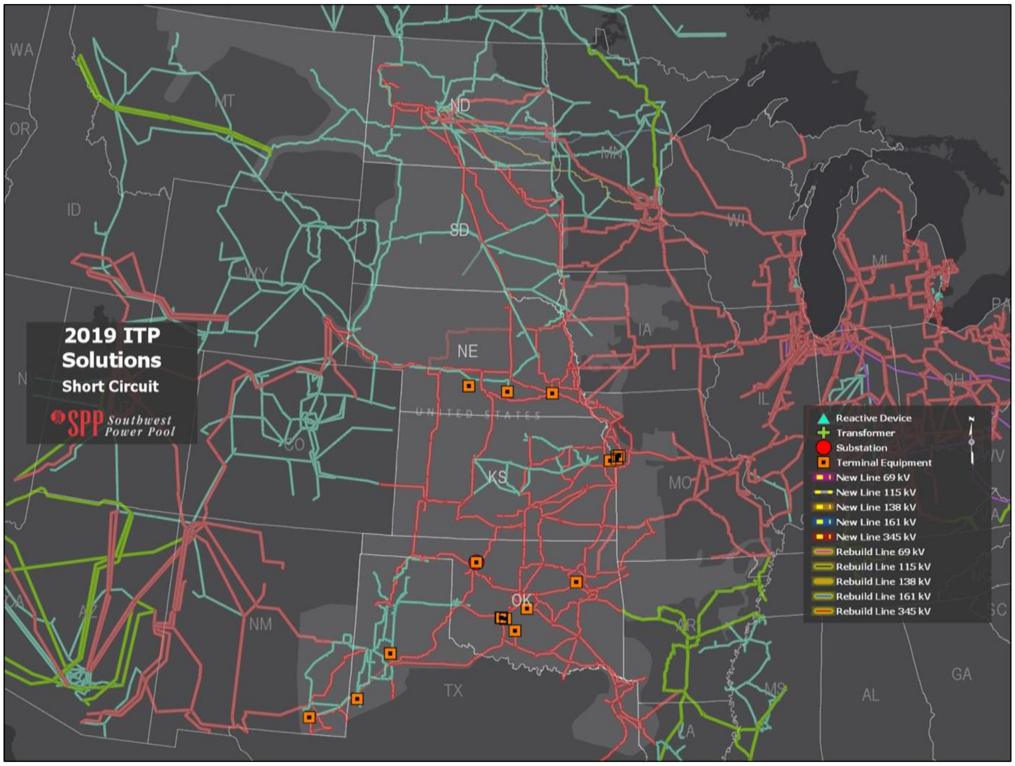


Figure 7.20: Short-Circuit Project portfolio

All short-circuit projects identified in the 2019 ITP were upgrades of overdutied breakers. These upgrades ensure SPP's members can meet short-circuit analysis requirements in the NERC TPL-001-4 standard.

Reliability Project	Area	Scenario*
Replace 21 breakers at Riverside Station 138 kV	AEPW	21S / BR
Replace eight breakers at Southwestern Station 138 kV	AEPW	21S / BR
Replace one breaker at Craig 161 kV	KCPL	21S / BR
Replace two breakers at Leeds 161 kV	KCPL	21S / BR
Replace two breakers at Midtown 161 kV	KCPL	21S / BR
Replace four breakers at Southtown 161 kV	KCPL	21S / BR
Replace one breaker at Moore 13.8 kV tertiary bus	NPPD	21S / BR
Replace two breakers at Hastings 115 kV	NPPD	21S / BR
Replace five breakers at Canaday 115 kV	NPPD	21S / BR

Reliability Project	Area	Scenario*
Replace two breakers at Westmoore 138 kV	OKGE	21S / BR
Replace three breakers at Santa Fe 138 kV	OKGE	21S / BR
Replace one breaker at Carlsbad Interchange 115 kV	SPS	21S / BR
Replace three breakers at Denver City North and South 115 kV	SPS	21S / BR
Replace three breakers at Hale County Interchange 115 kV	SPS	21S / BR
Replace one breaker at Washita 69 kV	WFEC	21S / BR
Replace 12 breakers at Mooreland 138/69 kV	WFEC	21S / BR
Replace three breakers at Anadarko 138 kV	WFEC	21S / BR

Table 7.3: Short-Circuit Projects

7.4 ECONOMIC PROJECTS

7.4.1 GRACEMONT-ANADARKO 138 KV REBUILD

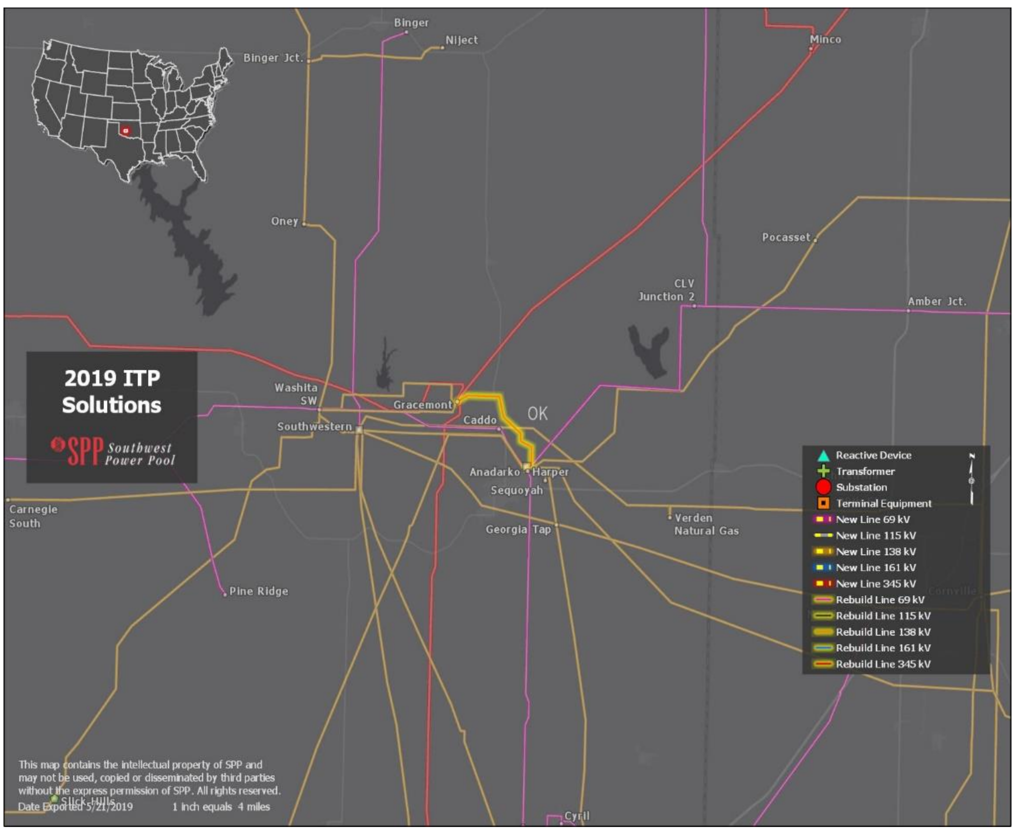


Figure 7.21: Gracemont-Anadarko 138 kV Rebuild

Southwest of Oklahoma City, near Anadarko, Oklahoma, the Gracemont-Anadarko 138 kV line becomes congested for loss of the Washita-Southwest Station 138 kV line. This area is impacted by west-to-east system flows and existing renewable generation on the 138 kV system. The Gracemont-Anadarko and Washita-Southwest Station lines form a parallel transmission path east from Washita, but the path to Anadarko has a lower capacity. This flowgate was identified in a previous ITP assessment and currently experiences operational congestion. The project selected to mitigate this issue was to leverage existing infrastructure and rebuild the Gracemont-Anadarko 138 kV line.

7.4.2 KINGFISHER JUNCTION-EAST KINGFISHER TAP 138 KV REBUILD

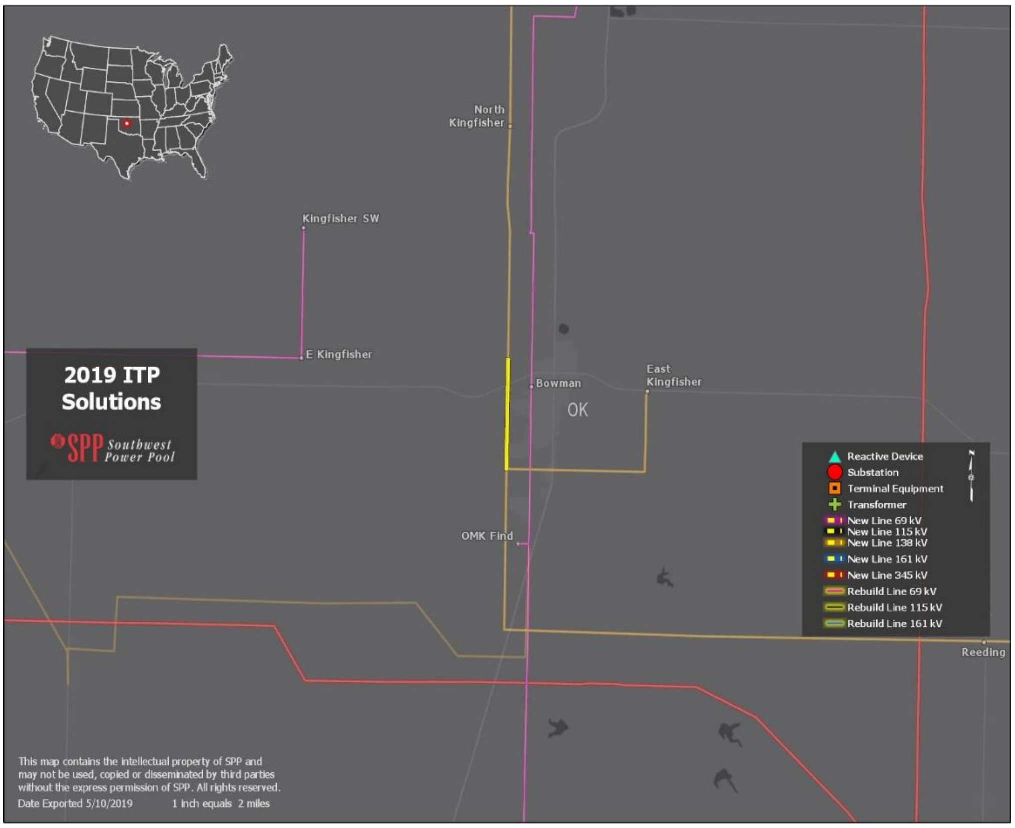


Figure 7.22: Kingfisher Junction-East Kingfisher Tap 138 kV Rebuild

Northwest of Oklahoma City, near Kingfisher, Oklahoma, the Kingfisher Junction-East Kingfisher Tap 138 kV line becomes congested for loss of the Dover-Dover Switch 138 kV line. This area is impacted by west-to-east and north-to-south bulk system flows. The Kingfisher Junction-East Kingfisher Tap and Dover-Dover Switch lines are part of a parallel transmission path east from Dover switch to Twin Lakes, but the path Kingfisher Junction-East Kingfisher Tap segment has a much lower capacity than the rest of the paths. The project selected to mitigate this issue was to leverage existing infrastructure and rebuild the Kingfisher Junction-East Kingfisher Tap 138 kV line.

7.4.3 SUNDOWN-AMOCO TAP 115 KV TERMINAL EQUIPMENT

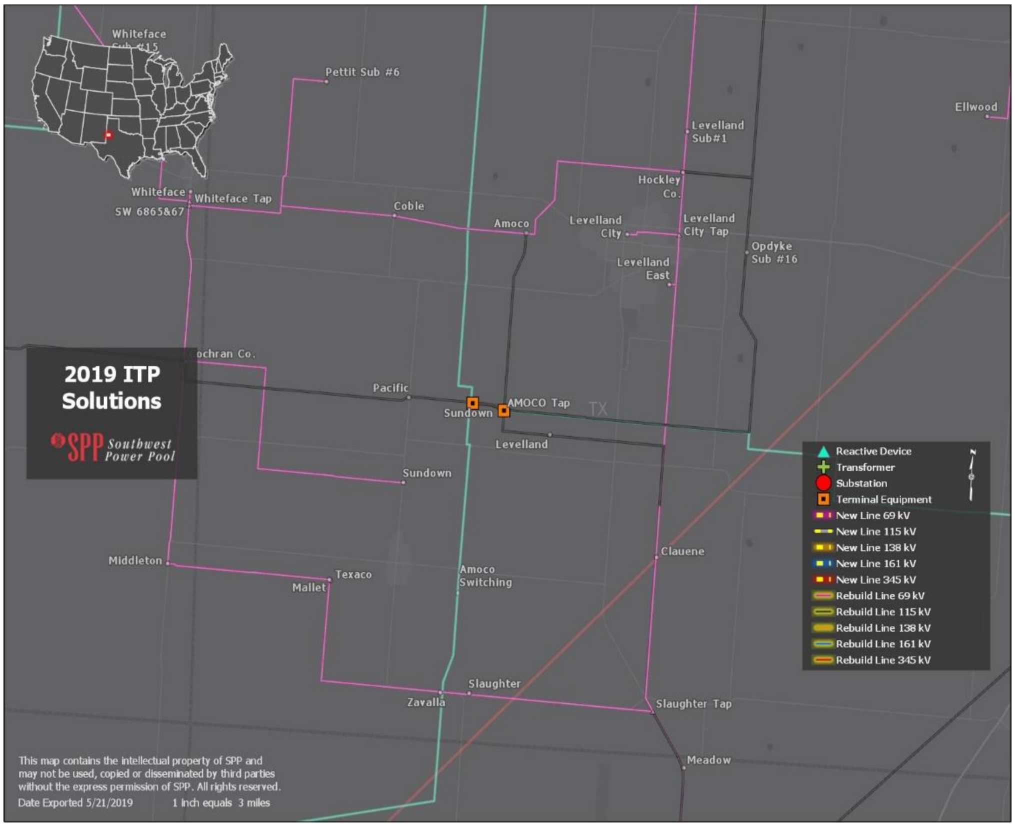


Figure 7.23: Sundown-Amoco Tap 115 kV terminal equipment

West of Lubbock, Texas, near Levelland, the Sundown-Amoco Tap 115 kV line becomes congested for loss of the Sundown-Amoco Switching Station 230 kV line. This area experiences north-to-south bulk system transfers to serve the New Mexico load pocket. It becomes especially congested during off-peak hours when conventional generation is offset by wind. In the 2015 ITP10 assessment, SPP issued an NTC resulting in a capacity increase on the Sundown-Amoco 230 kV line. This caused increasing flows that become more impactful to the underlying system when the line is outaged. The 230 kV flowgate currently experiences operational congestion. Once the upgrade is in service, it could be expected that congestion would move to the underlying system. Congestion is further increased by projected retirements in the southern SPS zone. The project selected to mitigate this issue is to replace any necessary terminal equipment at the Sundown and Amoco Tap 115 kV substations to increase the line rating.

7.4.4 SPEARMAN-HANSFORD 115 KV REBUILD

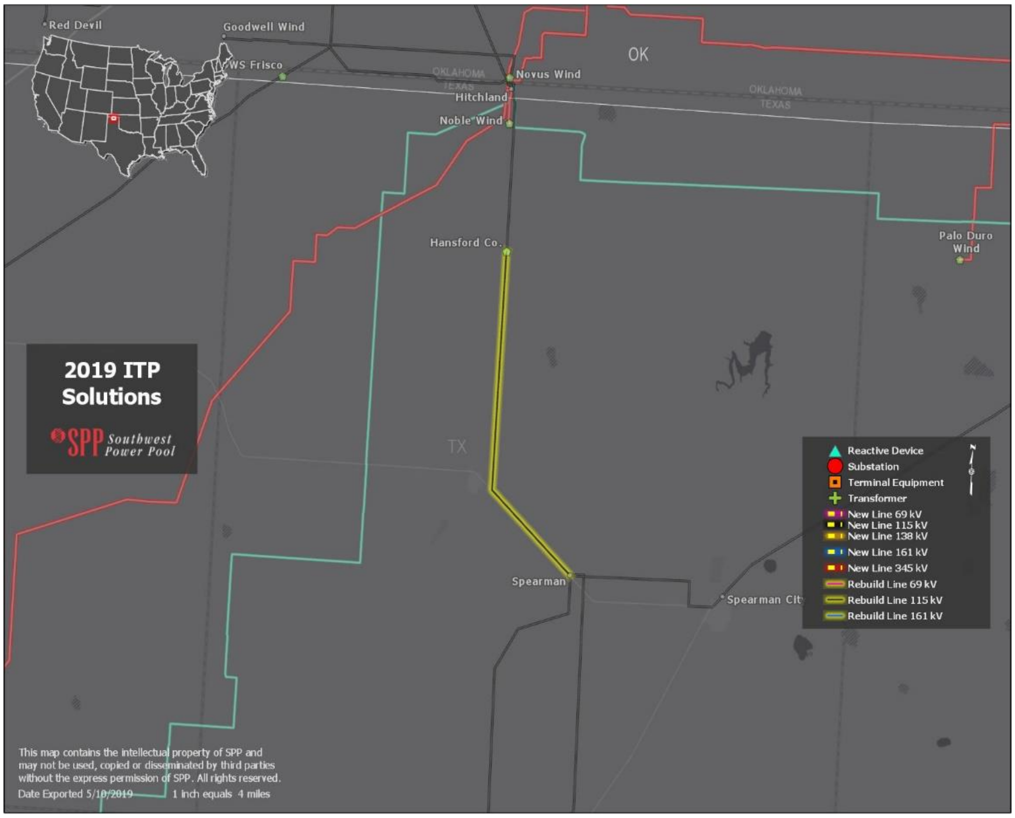


Figure 7.24: Spearman-Hansford 115 kV Rebuild

Northeast of Amarillo, Texas, near the Oklahoma border, the Spearman-Hansford 115 kV line becomes congested for loss of the Potter County 345/230 kV transformer. The 345 kV line north from the Potter substation is the only EHV transmission connecting the northern SPS system to the rest of SPP. The loss of this feed via the outage of the step-down transformer at Potter forces using the underlying HV system to support the typical north-to-south bulk system transfers into the SPS system. This line currently experiences operational congestion for multiple outages. The project selected to mitigate the issue is to rebuild the Spearman-Hansford 115 kV line.

7.4.5 LAWRENCE ENERGY CENTER-MIDLAND JUNCTION 115 KV TERMINAL EQUIPMENT

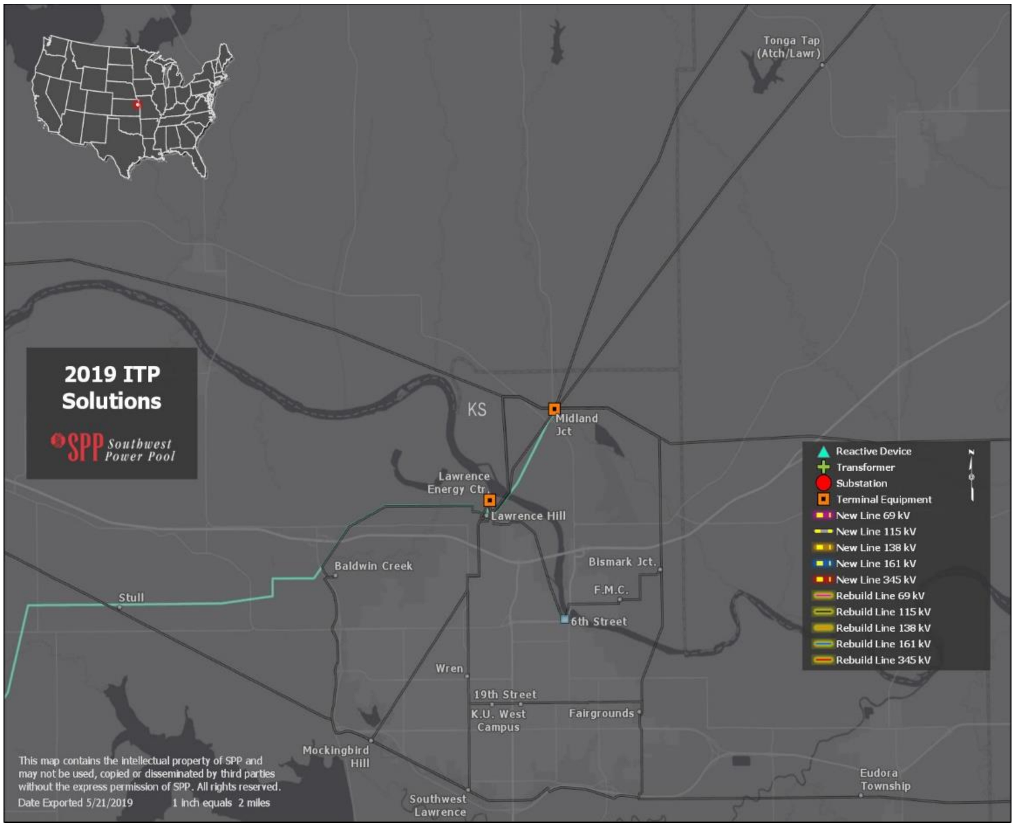


Figure 7.25: Lawrence Energy Center-Midland Junction 115 kV terminal equipment

On the north end of Lawrence, Kansas, the Lawrence Energy Center-Midland 115 kV line experiences congestion for loss of the Lawrence Hill 230/115 kV transformer. The 230 kV and 115 kV network serve to bring power from the Lawrence Energy Center to the area. When the 230 kV path from the plant to Midland Junction is lost, flows on the 115 kV system increase, creating congestion on the low capacity line. The project selected to mitigate this issue is to replace any necessary terminal equipment at Lawrence Energy Center and Midland Junction to increase the 115 kV line rating.

7.4.6 ARNOLD-RANSOM AND PILE-SCOTT CITY-SETAB 115 KV TERMINAL EQUIPMENT

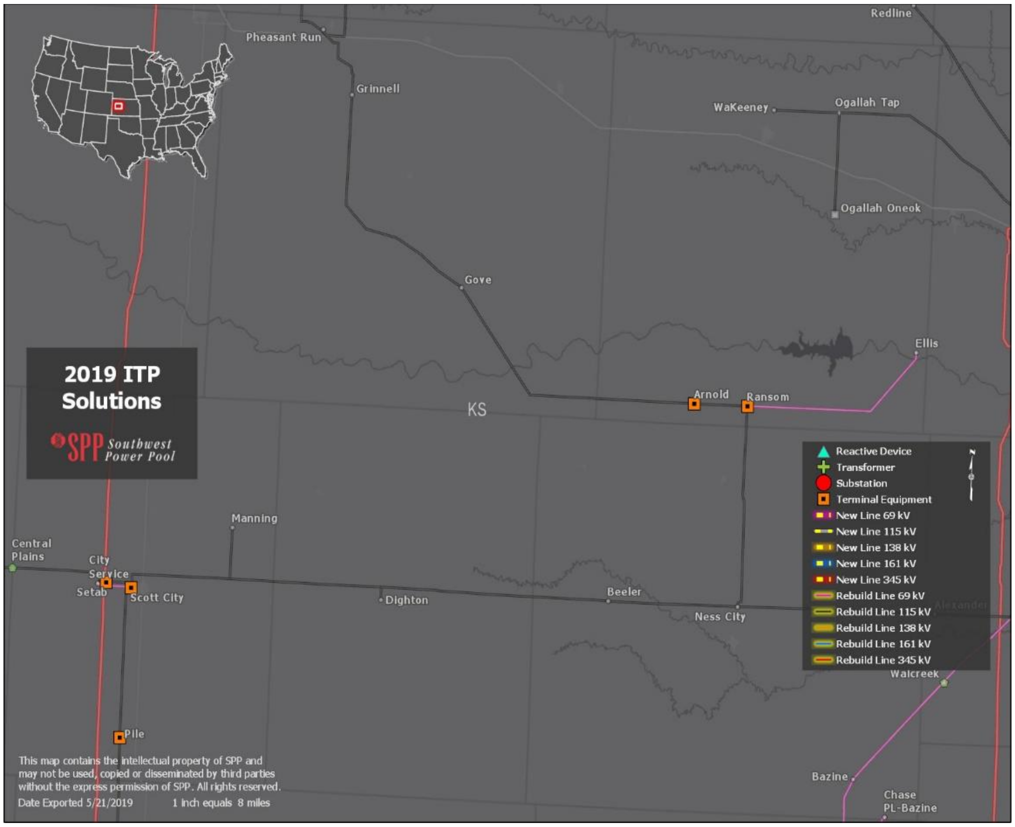


Figure 7.26: Arnold-Ransom and Pile-Scott City-Setab 115 kV terminal equipment

In central western Kansas, the Arnold-Ransom 115 kV line experiences congestion for loss of the Mingo-Setab 345 kV line. The Mingo-Setab 345 kV line supports north-to-south bulk system transfers from SPP north into Kansas. When the path is outaged, the flows transfer to the 115 kV system in northwest Kansas to continue the journey southeast. This line currently experiences operational congestion for outages of either 345 kV line making up the EHV corridor between Nebraska and western Kansas.

While developing solutions for this flowgate, it was observed that congestion moved to similar flowgates in the area: the Pile-Scott City and Scott City-Setab for loss of the Setab-Holcomb 345 kV line. To adequately address the area and allow bulk flows to continue southeast, all three flowgates need to be addressed. The project selected to mitigate these issue is to replace any necessary terminal equipment at Arnold, Ransom, Pile, Scott City, and Setab to increase the rating of the lines.

7.5 POLICY PROJECTS

No policy projects are required for the 2019 ITP assessment.

8 INFORMATIONAL PORTFOLIO ANALYSIS

8.1 BENEFITS

8.1.1 METHODOLOGY

Benefit metrics were used to measure the value and economic impacts of the final portfolio. The Benefit Metrics Manual[20] provides the definitions, concepts, calculations, and allocation methodologies for all approved metrics. The ESWG directed that the 2019 ITP benefit-to-cost ratios be calculated for the final portfolio using the Future 1 and Future 2 models. The benefit analysis is performed on all reliability and economic projects passed through the consolidation process. The benefit structure shown in Table 8.1 illustrates the metrics calculated as the incremental benefit of the projects included in the portfolios.

Metric Description
APC Savings
Savings Due to Lower Ancillary Service Needs and Production Costs
Avoided or Delayed Reliability Projects
Marginal Energy Losses
Capacity Cost Savings Due to Reduced On-Peak Transmission Losses
Reduction of Emissions Rates and Values
Public Policy Benefits
Assumed Benefit of Mandated Reliability Projects
Mitigation of Transmission Outage Costs
Increased Wheeling Through and Out Revenues

Table 8.1: Benefit Metrics

8.1.2 APC SAVINGS

APC captures the monetary cost associated with fuel prices, run times, grid congestion, unit operating costs, energy purchases, energy sales and other factors that directly relate to energy production by generating resources in the SPP footprint. Additional transmission projects aim to relieve system congestion and

[20] Benefit Metrics Manual

reduce costs through a combination of a more economical generation dispatch, more economical purchases and optimal revenue from sales.

To calculate benefits over the expected 40-year life of the projects[21], two years were analyzed, 2024 and 2029. APC savings were calculated accordingly for these years. The benefits are extrapolated for the initial five-year period based on the slope between the two points. After that, they are assumed to grow at an inflation rate of 2.5% per year. Each year's benefit was then discounted to 2024 using an 8% discount rate, and a 2.5% inflation rate from 2024 back to 2019. The sum of all discounted benefits was presented as the NPV benefit. This calculation was performed for every zone.

Figure 8.1 shows the regional APC savings for the recommended portfolio over 40 years, and Table 8.2 provides the zonal breakdown and the NPV estimates. Future 2 has higher congestion compared to Future 1. Therefore, the projects in the recommended portfolio provide more congestion relief in Future 2 than in Future 1, resulting in larger APC savings.

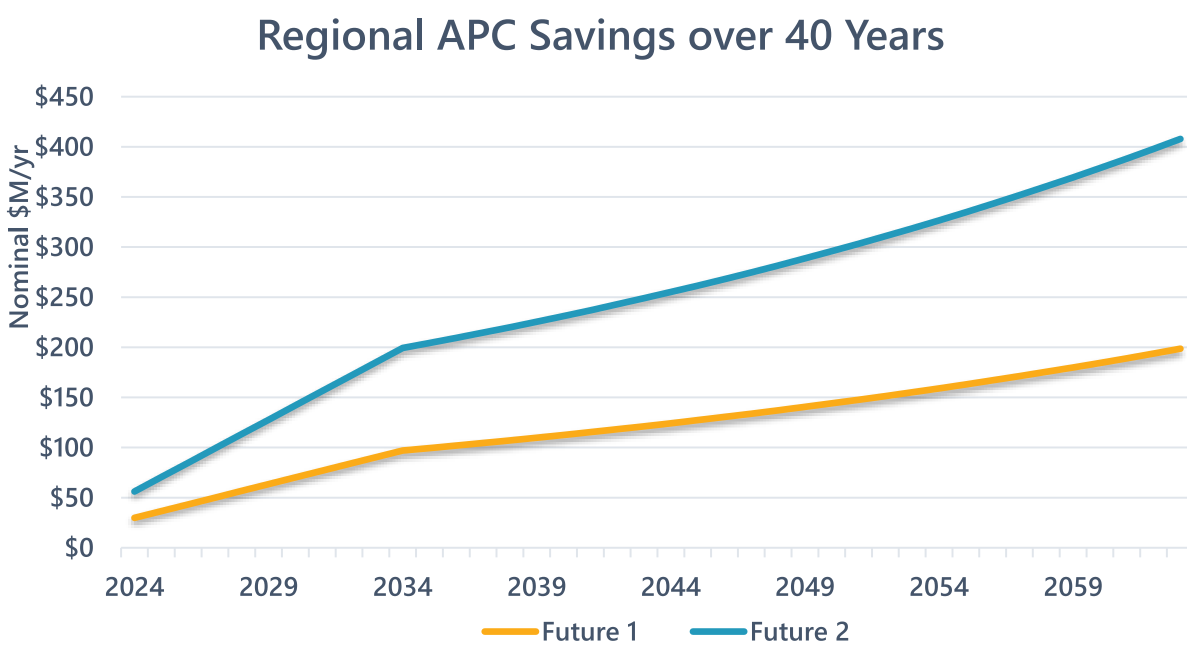


Figure 8.1: Regional APC Savings Estimated for the 40-year Study Period

	Future 1			Future 2		
Zone	**2024 ($M)**	**2029 ($M)**	**40-yr NPV ($2019M)**	**2024 ($M)**	**2029 ($M)**	**40-yr NPV ($2019M)**
AEPW	$14.2	$22.2	$322.8	$25.8	$37.3	$532.3
EMDE	$2.6	$4.8	$72.7	$3.3	$4.2	$57.6
GMO	$0.2	$0.6	$10.2	$2.2	$2.3	$30.7

[21] The SPP OATT requires that the portfolio be evaluated using a 40-year financial analysis.

	Future 1			Future 2		
Zone	**2024 ($M)**	**2029 ($M)**	**40-yr NPV ($2019M)**	**2024 ($M)**	**2029 ($M)**	**40-yr NPV ($2019M)**
GRDA	$10.2	$13.1	$182.2	$14.9	$25.5	$377.2
KCPL	$9.6	$11.4	$154.5	$10.3	$6.9	$70.7
LES	$0.5	$0.5	$6.0	$0.2	($0.5)	($10.5)
MIDW	($1.6)	($2.2)	($30.1)	($2.3)	($2.8)	($37.7)
MKEC	($4.3)	($5.4)	($75.0)	($5.4)	($6.0)	($79.3)
NPPD	$0.1	($0.2)	($3.8)	$0.3	$0.2	$1.5
OKGE	($4.7)	$0.5	$32.4	$5.5	$24.6	$407.7
OPPD	$0.1	$0.6	$10.1	$0.1	($0.0)	($1.4)
SPRM	$3.2	$4.7	$68.0	$3.3	$9.0	$142.0
SPS	($9.6)	($8.2)	($98.3)	($8.7)	$0.9	$58.4
SUNC	($1.6)	($1.8)	($23.5)	($2.0)	($1.9)	($23.9)
SWPA	$1.1	$0.1	($3.2)	($0.1)	$0.7	$12.8
UMZ	$0.0	($0.4)	($6.9)	($0.4)	($1.6)	($25.8)
WERE	$8.3	$18.6	$288.9	$7.2	$21.4	$343.0
WFEC	$1.5	$4.3	$68.4	$2.0	$7.8	$127.6
TOTAL	**$29.8**	**$63.4**	**$975.3**	**$56.1**	**$127.7**	**$1,982.8**

Table 8.2: APC Savings by Zone

Table 8.3 provides the zonal breakdown and the NPV estimates for the SPP other zone. This zone includes merchant generation (without contractual arrangements with load-serving entities) and additional renewable resource plan wind resources. The calculation for this zone is 100% production cost minus sales to other zones (revenue).

	Future 1			Future 2		
Zone	**2024 ($M)**	**2029 ($M)**	**40-yr NPV ($2019M)**	**2024 ($M)**	**2029 ($M)**	**40-yr NPV ($2019M)**
OTHSPP	$100.9	$121.0	$1,643.1	$143.0	$143.0	$1,824.9

Table 8.3: Other SPP APC Benefit

8.1.3 REDUCTION OF EMISSION RATES AND VALUES

Additional transmission may result in a lower fossil-fuel burn (for example, less coal-intensive generation), resulting in less SO_2, NOX, and CO_2 emissions. Such a reduction in emissions is a benefit that is already monetized through the APC savings metric, based on the assumed allowance prices for these effluents. Note that neither ITP future assumes any allowance prices for CO_2.

8.1.4 SAVINGS DUE TO LOWER ANCILLARY SERVICE NEEDS AND PRODUCTION COSTS

Ancillary services, such as spinning reserves, ramping (up/down), regulation, and 10-minute quick start are essential for the reliable operation of the electrical system. Additional transmission can decrease the ancillary services costs by: (a) reducing the ancillary services quantity needed, or (b) reducing the procurement costs for that quantity.

The ancillary services needs in SPP are determined according to SPP's market protocols and do not change based on transmission. Therefore, the savings associated with the "quantity" effect are assumed to be zero.

The costs of providing ancillary services are captured in the APC metrics. The production cost simulations set aside the static levels of resources to provide regulation and spinning reserves. As a result, the benefits related to "procurement cost" effect are already included as a part of the APC savings presented in this report.

8.1.5 AVOIDED OR DELAYED RELIABILITY PROJECTS

Potential reliability needs are reviewed to determine if the upgrades proposed for economic or policy reasons defer or replace any reliability upgrades. The avoided or delayed reliability project benefit represents the costs associated with these additional reliability upgrades that would otherwise have to be pursued.

To calculate the avoided or delayed reliability projects benefit for the recommended portfolio, the ability for economic projects to avoid or delay a base reliability project is analyzed and identified in the optimization milestone. No overlap was identified, therefore, no avoided or delayed reliability projects were identified, and the associated benefits are estimated to be zero.

8.1.6 CAPACITY COST SAVINGS DUE TO REDUCED ON-PEAK TRANSMISSION LOSSES

Transmission line losses result from the interaction of line materials with the energy flowing over the line. This constitutes an inefficiency inherent to all standard conductors. Line losses across the SPP system are directly related to system impedance. Transmission projects often reduce losses during peak load conditions, which lowers the costs associated with additional generation capacity needed to meet the capacity requirements.

The capacity cost savings for the recommended portfolio are calculated based on the on-peak losses estimated in the base reliability powerflow model. The loss reductions are then multiplied by 112% to estimate the reduction in installed capacity requirements. The value of capacity savings is monetized by applying a net cost of new entry (net CONE) of $85.61/kW-yr in 2018 dollars. The net CONE value was obtained from Attachment AA Resource Adequacy–Attachment AA Section 14 of the tariff. The net cone was assumed to grow at an inflation rate of 2.5% for each study year, $99.2 for 2024, and $112.3 for 2029. Table 8.4 displays the associated capacity savings for each zone in each study year and the 40-year NPV.

Base Reliability			
Zone	2024 ($M)	2029 ($M)	40-yr NPV (2019 $M)
AEPW	$0.10	$0.07	$0.82
EMDE	$0.03	$0.05	$0.69
GMO	$0.06	$0.07	$0.88
GRDA	$0.01	$0.01	$0.14
KCPL	$0.36	$0.40	$5.25
LES	$0.01	$0.01	$0.07
MIDW	$0.00	$0.00	$0.01
MKEC	($0.00)	$0.00	$0.02
NPPD	$0.07	$0.10	$1.46
OKGE	($0.16)	($0.20)	($2.70)
OPPD	$0.02	$0.02	$0.27
SPRM	($0.00)	($0.00)	($0.05)
SPS	$0.01	$0.02	$0.31
SUNC	($0.02)	($0.02)	($0.21)
SWPA	$0.02	$0.04	$0.65
UMZ	$0.01	$0.01	$0.10
WERE	$0.39	$0.42	$5.59
WFEC	$0.07	$0.08	$0.00
Total	**$1.0**	**$1.1**	**$13.3**

Table 8.4: On-Peak Loss Reduction and Associated Capacity Cost Savings

8.1.7 ASSUMED BENEFIT OF MANDATED RELIABILITY PROJECTS

This metric monetizes the benefits of reliability projects required to meet compliance and mitigate SPP Criteria violations. The regional benefits are assumed to be equal to the 40-year NPV of ATRRs of the projects, totaling **$100.8 million** in 2019 dollars.

The system reconfiguration approach to allocate zonal benefits utilizes the powerflow models to measure incremental flows shifted onto the existing system during outage of the proposed reliability upgrade. This is used as a proxy for how much each upgrade reduces flows on the existing transmission facilities in each zone. Results from the production cost simulations are used to determine hourly flow direction on the upgrades and applied as weighting factors for the powerflow results.

Table 8.5 summarize the system reconfiguration analysis results and the benefit allocation factors for different voltage levels. The table shows the overall zonal benefits calculated by applying these allocation factors.

Mandated Reliability Benefits Base Reliability and Short-Circuit									
< 100 kV		100–300 kV			> 300 kV			All Projects	
SPP-wide Benefit	$2.84	$98			$0			$101	
Zone	100% SR	67% SR	33% LRS	Wtd. Avg	33% SR	67% LRS	Wtd. Avg	Allocation	Benefit 2019 $M
AEPW	14.2%	14.7%	20.6%	16.7%	0.0%	20.6%	13.7%	16.6%	$16.7
EMDE	0.3%	0.6%	2.4%	1.2%	0.0%	2.4%	1.6%	1.2%	$1.2
GMO	0.9%	5.6%	3.8%	5.0%	0.0%	3.8%	2.6%	4.9%	$5.0
GRDA	0.1%	4.3%	1.7%	3.4%	0.0%	1.7%	1.1%	3.3%	$3.4
KCPL	1.0%	3.1%	7.6%	4.6%	0.0%	7.6%	5.0%	4.5%	$4.5
LES	10.2%	0.4%	1.5%	0.8%	0.0%	1.5%	1.0%	1.1%	$1.1
MIDW	0.3%	0.4%	0.8%	0.5%	0.0%	0.8%	0.5%	0.5%	$0.5
MKEC	0.9%	0.8%	1.3%	1.0%	0.0%	1.3%	0.8%	1.0%	$1.0
NPPD	2.5%	3.2%	6.0%	4.2%	0.0%	6.0%	4.0%	4.1%	$4.2
OKGE	3.6%	19.4%	13.1%	17.3%	0.0%	13.1%	8.7%	16.9%	$17.1
OPPD	4.5%	4.8%	4.8%	4.8%	0.0%	4.8%	3.2%	4.8%	$4.8
SPRM	0.1%	0.3%	1.3%	0.6%	0.0%	1.3%	0.9%	0.6%	$0.6
SPS	6.6%	19.8%	11.6%	17.1%	0.0%	11.6%	7.8%	16.8%	$16.9
SUNC	0.4%	3.9%	0.9%	2.9%	0.0%	0.9%	0.6%	2.9%	$2.9
SWPA	0.8%	1.8%	0.5%	1.4%	0.0%	0.5%	0.4%	1.4%	$1.4
UMZ	0.1%	1.1%	8.8%	3.7%	0.0%	8.8%	5.9%	3.6%	$3.6
WERE	35.5%	8.6%	3.3%	6.8%	0.0%	3.3%	2.2%	7.7%	$7.7
WFEC	17.9%	6.8%	10.1%	7.9%	0.0%	10.1%	6.7%	8.2%	$8.2
Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**0.0%**	**100.0%**	**66.7%**	**100.0%**	**$100.8**

Table 8.5: Mandated Reliability Benefits

8.1.8 BENEFIT FROM MEETING PUBLIC POLICY GOALS

This metric represents the economic benefit provided by the transmission upgrades for facilitating public policy goals. In this study, the scope is limited to meeting public policy goals related to renewable energy. System-wide benefits are assumed to be equal to the cost of policy projects.

Since no policy projects were identified as a part of the recommended portfolio, the associated benefits are estimated to be zero.

8.1.9 MITIGATION OF TRANSMISSION OUTAGE COSTS

The standard production cost simulations used to estimate APC savings assume that transmission lines and facilities are available during all hours of the year, ignoring the added congestion-relief and production cost benefits of new transmission facilities during the planned and unplanned outages of existing transmission facilities.

To estimate the incremental savings associated with the mitigation of transmission outage costs, the production cost simulations can be augmented for a realistic level of transmission outages. Due to the significant effort needed to develop these augmented models for each case, the findings from the RCAR II study were used to calculate this benefit metric for the consolidated portfolio as a part of this ITP assessment.

In the RCAR analysis, adding a subset of historical transmission outage events to the production cost simulations increased the APC savings by 11.3%.[22,23] Applying this ratio to the APC savings estimated for the recommended portfolio translates to a 40-year NPV of benefits of **$110 million** for Future 1 and **$223 million** for Future 2 in 2019 dollars. These benefits are allocated based upon the load ratio share of the region. Table 8.6 shows the outage mitigation benefits allocated to each SPP zone.

Zone	Future 1 (2019 $M)	Future 2 (2019 $M)
AEPW	$22.6	$45.9
EMDE	$2.6	$5.3
GMO	$4.2	$8.6
GRDA	$1.8	$3.7
KCPL	$8.3	$16.8
LES	$1.6	$3.3
MIDW	$0.8	$1.7
MKEC	$1.4	$2.8
NPPD	$6.6	$13.5
OKGE	$14.4	$29.3
OPPD	$5.2	$10.7

22 SPP Regional Cost Allocation Review Report, October 8, 2013 (pp. 36–37)
23 As directed by ESWG, SPP will periodically review historical outage data and update additional APC savings ratio for future studies. Although the outage data was not updated for the 2015 ITP10, it is being reviewed and updated for the RCAR II assessment.

Zone	Future 1	Future 2
	(2019 $M)	(2019 $M)
SPRM	$1.5	$3.0
SPS	$12.8	$26.0
SUNC	$1.0	$2.1
SWPA	$0.6	$1.2
UMZ	$9.7	$19.7
WERE	$11.1	$22.5
WFEC	$3.6	$7.3
TOTAL	**$109.8**	**$223.1**

Table 8.6: Transmission Outage Cost Mitigation Benefits by Zone

8.1.10 INCREASED WHEELING THROUGH AND OUT REVENUES

Increasing ATC with a neighboring region improves import and export opportunities for the SPP footprint. Increased interregional transmission capacity that allows for increased through and out transactions will also increase SPP wheeling revenues.

To estimate how increased ATC could affect the wheeling services sold, the historical long-term firm transmission service request (TSR) allowed by the historical NTC projects are analyzed and compared against the ATC increase in the 2014 powerflow models estimated based on a FCITC analysis. As summarized in Table 8.7, the NTC projects that have been put in-service under SPP's highway/byway cost allocation methodology enabled 13 long-term TSRs to be sold between 2010 and 2014. The TSRs remain active for 2019. The amount of capacity granted for these TSRs add up to 1,402 MW. The associated wheeling revenues are estimated to be $45 million annually based on current SPP tariff rates. The results of the FCITC analysis are summarized in Table 8.8. The export ATC increase in the 2014 powerflow models is calculated to be 1,142 MW, which is comparable to the amount of firm capacity granted for the incremental TSRs sold historically for 2019.

Point of Delivery	Number of Firm PtP Service Requests	MW Capacity Granted	2014 Wheeling Revenues in $million			
			Sch 7 Zonal	Sch 11 Reg-Wide	Sch 11 Thru & Out Zonal	TOTAL
AECI	6	716	$7.9	$9.6	$3.5	**$20.9**
KACY	1	100	$1.1	$1.3	$0.5	**$2.9**
Entergy	6	586	$10.3	$7.8	$2.8	**$21.0**
TOTAL	**13**	**1,402**	**$19.3**	**$18.8**	**$6.8**	**$44.9**

Table 8.7: Estimated Wheeling Revenues from Incremental Long-Term TSRs Sold (2010–2014)

Export ATC in 2014 Base Case	**1,630 MW**
Export ATC in 2014 Change Case	**2,943 MW**
Increase in Export ATC due to NTCs	**1,313 MW**
Incremental TSRs Sold due to NTCs	**1,402 MW**
TSRs Sold as a Percent of Increase in Export ATC	**107%**

Table 8.8: Historical Ratio of TSRs Sold against Increase in Export ATC

The 2024 and 2029 base reliability powerflow models were utilized for the FCITC analysis on the consolidated portfolio. The ratio of TSRs sold as a percent of increase in export ATC is capped at 100%, as incremental TSR sales would not be expected to exceed the amount of increase in export ATC. The recommended portfolio increased the export ATC by 109 MW in 2024 and 159 MW in 2029. Applying the historical ratio suggests the recommended portfolio could enable incremental TSRs by the same amount, generating additional wheeling revenues of $4-7 million annually.

The 40-year NPV of benefits is estimated to be **$119 million**. These benefits are allocated based on the current revenue sharing method in the tariff. Figure 8.2 shows the distribution of wheeling revenue benefits for each SPP zone.

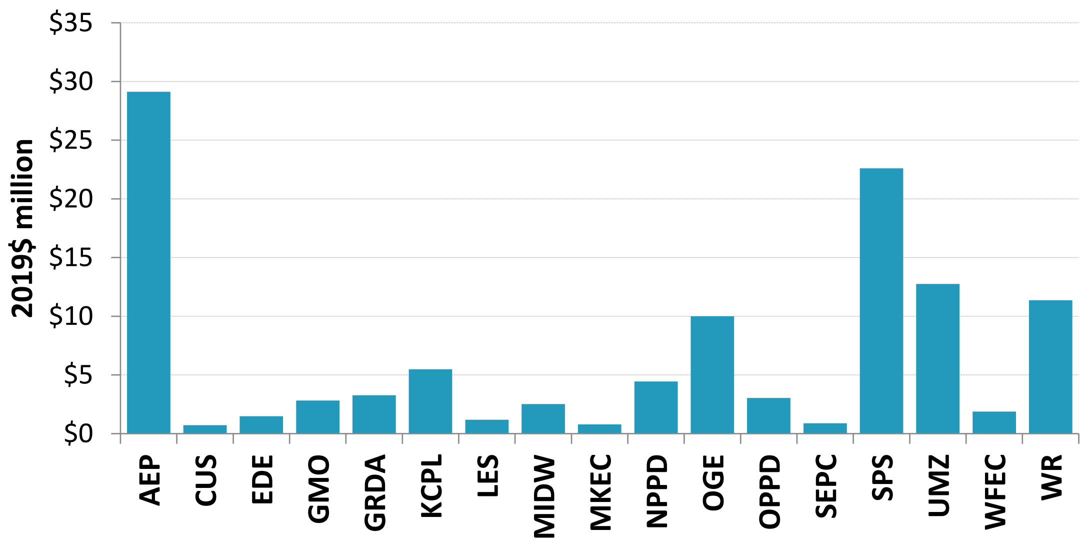


Figure 8.2: Increased Wheeling Revenue Benefits by Zone (40-year NPV)

8.1.11 MARGINAL ENERGY LOSSES BENEFIT

The standard production cost simulations used to estimate APC do not reflect the impact of transmission upgrades on the MWh quantity of transmission losses. To make run-times more manageable, the load in the production cost simulations is "grossed up" for average transmission losses for each zone. These loss assumptions do not change with additional transmission. Therefore, the traditional APC metric does not capture the benefits from reduced MWh quantity of losses.

APC savings due to such energy loss reductions can be estimated by post-processing the marginal loss component (MLC) of the LMPs from simulation results and applying a methodology[24] for marginal energy losses, which accounts for losses on generation and market imports. The 40-year NPV of benefits is estimated to be $168.7 million in future 1 and $34.9 million in future 2, as shown in Table 8.9 below.

	Future 1	Future 2
	40-yr NPV	40-yr NPV
Zone	(2019 $M)	(2019 $M)
AEPW	$19.0	($0.6)
EMDE	$15.6	$4.0
GMO	$7.0	$2.7
GRDA	($5.2)	($22.1)
KCPL	$31.5	$29.43
LES	$2.1	$1.13
MIDW	($0.6)	($0.34)
MKEC	$5.7	$4.66
NPPD	$12.7	$16.54
OKGE	$15.3	($26.74)
OPPD	$3.3	$4.49
SPRM	$1.5	($4.76)
SPS	$44.1	$10.22
SUNC	($0.1)	($0.81)
SWPA	$3.0	$0.89
UMZ	$15.2	$12.76
WERE	$6.4	$11.31
WFEC	($7.7)	($7.94)
TOTAL	**$168.7**	**$34.9**

Table 8.9: Energy Losses Benefit by Zone

8.1.12 SUMMARY

Table 8.10 through Table 8.13 summarize the 40-year NPV of the estimated benefit metrics and costs and the resulting benefit-to-cost ratios for each SPP zone.

For the region, the benefit-to-cost ratio is estimated to be 3.5 in Future 1 and 5.8 in Future 2. The higher benefit-to-cost ratio in Future 2 is driven by the APC savings due to higher congestion relief.

[24] As described in the Benefit Metric Manual

Future 1 Present Value of 40-yr Benefits for the 2024-2063 Period (in 2019 $million)										Present	Est.
Zone	APC Savings	Avoided or Delayed Reliability Projects	Capacity Savings from Reduced On-peak Losses	Assumed Benefit of Mandated Reliability Projects	Benefit from Meeting Public Policy Goals	Mitigation of Trans-mission Outage Costs	Increased Wheeling Through and Out Revenues	Marginal Energy Losses Benefits	Total Benefits	Value of 40-yr ATRRs (in 2019 $million)	Benefit/ Cost Ratio
AEPW	$323	$0	$1	$17	$0	$23	$29	$19	$409	$105	3.9
EMDE	$73	$0	$1	$1	$0	$3	$1	$16	$94	$8	11.6
GMO	$10	$0	$1	$5	$0	$4	$3	$7	$30	$13	2.3
GRDA	$182	$0	$0	$3	$0	$2	$3	($5)	$185	$6	32.8
KCPL	$155	$0	$5	$5	$0	$8	$6	$15	$193	$28	6.9
LES	$6	$0	$0	$1	$0	$2	$1	$32	$41	$5	8.3
MIDW	($30)	$0	$0	$1	$0	$1	$3	$2	($24)	$3	(9.4)
MKEC	($75)	$0	$0	$1	$0	$1	$1	($1)	($73)	$4	(16.9)
NPPD	($4)	$0	$1	$4	$0	$7	$4	$6	$18	$27	0.7
OKGE	$32	$0	($3)	$17	$0	$14	$10	$13	$82	$46	1.8
OPPD	$10	$0	$0	$5	$0	$5	$3	$15	$38	$16	2.4
SPRM	$68	$0	($0)	$1	$0	$1	$1	$3	$74	$5	16.1
SPS	($98)	$0	$0	$17	$0	$13	$23	$1	($46)	$49	(0.9)
SUNC	($24)	$0	($0)	$3	$0	$1	$1	($0)	($19)	$7	(2.6)
SWPA	($3)	$0	$1	$1	$0	$1	$4	$3	$7	$2	3.7
UMZ	($7)	$0	$0	$4	$0	$10	$13	$44	$63	$30	2.1
WERE	$289	$0	$6	$8	$0	$11	$11	$6	$330	$57	5.9
WFEC	$68	$0	$0	$8	$0	$4	$2	($8)	$73	$17	4.3
Total	**$975**	**$0**	**$13**	**$101**	**$0**	**$110**	**$119**	**$169**	**$1,475**	**$427**	**3.5**

Table 8.10: Estimated 40-year NPV of Benefit Metrics and Costs - Zonal

Future 2 Present Value of 40-yr Benefits for the 2024-2063 Period (in 2019 $million)										Present	Est.
Zone	APC Savings	Avoided or Delayed Reliability Projects	Capacity Savings from Reduced On-peak Losses	Assumed Benefit of Mandated Reliability Projects	Benefit from Meeting Public Policy Goals	Mitigation of Trans-mission Outage Costs	Increased Wheeling Through and Out Revenues	Marginal Energy Losses Benefits	Total Benefits	Value of 40-yr ATRRs (in 2019 $million)	Benefit/ Cost Ratio
AEPW	$532	$0	$1	$17	$0	$46	$29	($1)	$622	$105	6.0
EMDE	$58	$0	$1	$1	$0	$5	$1	$4	$70	$8	8.6
GMO	$31	$0	$1	$5	$0	$9	$3	$3	$50	$13	3.8
GRDA	$377	$0	$0	$3	$0	$4	$3	($22)	$365	$6	64.5
KCPL	$71	$0	$5	$5	$0	$17	$6	$13	$115	$28	4.1
LES	($11)	$0	$0	$1	$0	$3	$1	$29	$24	$5	4.9
MIDW	($38)	$0	$0	$1	$0	$2	$3	$1	($32)	$3	(12.4)
MKEC	($79)	$0	$0	$1	$0	$3	$1	($0)	($75)	$4	(17.5)
NPPD	$2	$0	$1	$4	$0	$13	$4	$5	$29	$27	1.1
OKGE	$408	$0	($3)	$17	$0	$29	$10	$17	$476	$46	10.5
OPPD	($1)	$0	$0	$5	$0	$11	$3	($27)	($10)	$16	(0.6)
SPRM	$142	$0	($0)	$1	$0	$3	$1	$4	$151	$5	32.8
SPS	$58	$0	$0	$17	$0	$26	$23	($5)	$117	$49	2.4
SUNC	($24)	$0	($0)	$3	$0	$2	$1	($1)	($19)	$7	(2.6)
SWPA	$13	$0	$1	$1	$0	$1	$4	$1	$21	$2	11.6
UMZ	($26)	$0	$0	$4	$0	$20	$13	$10	$20	$30	0.7
WERE	$343	$0	$6	$8	$0	$22	$11	$11	$401	$57	7.1
WFEC	$128	$0	$0	$8	$0	$7	$2	($8)	$136	$17	7.9
Total	**$1,983**	**$0**	**$13**	**$101**	**$0**	**$223**	**$119**	**$35**	**$2,462**	**$427**	**5.8**

Table 8.11: Estimated 40-year NPV of Benefit Metrics and Costs – Zonal

	Future 1 Present Value of 40-yr Benefits for the 2024-2063 Period (in 2019 $million)									Present Value of 40-yr ATRRs (in 2019 $million)	Est. Benefit/ Cost Ratio
State	APC Savings	Avoided or Delayed Reliability Projects	Capacity Savings from Reduced On-peak Losses	Assumed Benefit of Mandated Reliability Projects	Benefit from Meeting Public Policy Goals	Mitigation of Trans-mission Outage Costs	Increased Wheeling Through and Out Revenues	Marginal Energy Losses Benefits	Total Benefits		
Arkansas	$107	$0	($0)	$10	$0	$8	$8	$2	$135	$51	2.6
Iowa	($1)	$0	$0	$0	$0	$0	$1	$1	$1	$0	3.7
Kansas	($55)	$0	$3	$10	$0	$17	$20	$54	$48	$97	0.5
Louisiana	$43	$0	$0	$2	$0	$3	$4	$3	$55	$14	3.9
Minnesota	($0)	$0	$0	$0	$0	$0	$0	$0	$0	$0	3.7
Missouri	$249	$0	$4	$12	$0	$14	$8	$29	$316	$109	2.9
Montana	($0)	$0	$0	$0	$0	$0	$0	$0	$0	$0	3.7
Oklahoma	$633	$0	$4	$34	$0	$35	$36	$20	$763	$77	9.9
Nebraska	$12	$0	$2	$10	$0	$14	$9	$53	$99	$35	2.8
New Mexico	($27)	$0	$0	$5	$0	$4	$6	$0	($12)	$5	(2.7)
North Dakota	($1)	$0	$0	$1	$0	$0	$2	$1	$3	$1	3.7
South Dakota	($1)	$0	$0	$0	$0	$0	$1	$1	$2	$0	3.7
Texas	$16	$0	$0	$16	$0	$15	$23	$6	$77	$38	2.0
Wyoming	($0)	$0	$0	$0	$0	$0	$0	$0	$0	$0	3.7
TOTAL	**$975**	**$0**	**$13**	**$101**	**$0**	**$110**	**$119**	**$169**	**$1,475**	**$427**	**3.5**

Table 8.12: Estimated 40-year NPV of Benefit Metrics and Costs – State

Future 2 Present Value of 40-yr Benefits for the 2024-2063 Period (in 2019 $million)										Present	Est.
State	APC Savings	Avoided or Delayed Reliability Projects	Capacity Savings from Reduced On-peak Losses	Assumed Benefit of Mandated Reliability Projects	Benefit from Meeting Public Policy Goals	Mitigation of Trans-mission Outage Costs	Increased Wheeling Through and Out Revenues	Marginal Energy Losses Benefits	Total Benefits	Value of 40-yr ATRRs (in 2019 $million)	Benefit/ Cost Ratio
Arkansas	$174	$0	$0	$8	$0	$15	$7	($8)	$196	$32	6.1
Iowa	$2	$0	$0	$0	$0	$0	$1	$0	$4	$0	11.5
Kansas	$320	$0	$7	$31	$0	$67	$40	$25	$488	$140	3.5
Louisiana	$71	$0	$0	$2	$0	$6	$4	($0)	$83	$14	6.0
Minnesota	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	11.6
Missouri	$507	$0	$2	$13	$0	$21	$9	($4)	$546	$35	15.7
Montana	$1	$0	$0	$0	$0	$0	$0	$0	$1	$0	11.6
Oklahoma	$275	$0	$6	$20	$0	$65	$33	($1)	$396	$117	3.4
Nebraska	$513	$0	($3)	$18	$0	$34	$14	$22	$596	$53	11.3
New Mexico	($7)	$0	($0)	$1	$0	$1	$0	($0)	($5)	$2	(2.6)
North Dakota	$5	$0	$0	$1	$0	$0	$2	$0	$8	$1	11.6
South Dakota	$4	$0	$0	$0	$0	$0	$1	$0	$6	$0	11.5
Texas	$116	$0	$0	$6	$0	$13	$8	($1)	$143	$32	4.5
Wyoming	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	11.6
TOTAL	**$1,983**	**$0**	**$13**	**$101**	**$0**	**$223**	**$119**	**$35**	**$2,462**	**$427**	**5.8**

Table 8.13: Estimated 40-year NPV of Benefit Metrics and Costs – State

8.2 RATE IMPACTS

The rate impact to the average retail residential ratepayer in SPP was computed for the recommended portfolio. Rate impact costs and benefits[25] are allocated to the average retail residential ratepayer based on an estimated residential consumption of 1,000 kWh per month. Benefits and costs for the 2029 study year were used to calculate rate impacts. All 2029 benefits and costs are shown in 2019 dollars, discounting at a 2.5% inflation rate.

The retail residential rate impact benefit is subtracted from the retail residential rate impact cost to obtain a net rate impact cost by zone. If the net rate impact cost is negative, it indicates a net benefit to the zone. The rate impact costs and benefits are shown in Table 8.14 through Table 8.17. There is a monthly net benefit for the average SPP residential ratepayer of 4 cents for Future 1. There is a monthly net benefit for the average SPP residential ratepayer of 23 cents for Future 2.

Zone	One-Year ATRR Costs	One-Year Benefit	Rate Impact-Cost	Rate Impact Benefit	Net Impact
AEPW	$9,079	$17,334	$0.17	$0.32	($0.15)
EMDE	$760	$3,770	$0.12	$0.59	($0.47)
GMO	$1,231	$491	$0.13	$0.05	$0.08
GRDA	$528	$10,268	$0.09	$1.72	($1.63)
KCPL	$2,575	$8,908	$0.18	$0.62	($0.44)
LES	$466	$364	$0.11	$0.09	$0.02
MIDW	$240	($1,689)	$0.09	($0.62)	$0.71
MKEC	$400	($4,245)	$0.12	($1.24)	$1.36
NPPD	$2,367	($146)	$0.10	($0.01)	$0.10
OKGE	$4,234	$420	$0.17	$0.02	$0.15
OPPD	$1,528	$473	$0.12	$0.04	$0.08
SPRM	$428	$3,694	$0.13	$1.12	($0.99)
SPS	$4,448	($6,421)	$0.14	($0.20)	$0.33
SUNC	$675	($1,376)	$0.24	($0.50)	$0.74
SWPA	$171	$108	$0.17	$0.11	$0.06
UMZ	$2,822	($297)	$0.12	($0.01)	$0.14
WERE	$5,028	$14,558	$0.16	$0.46	($0.30)
WFEC	$1,486	$3,344	$0.12	$0.26	($0.14)
TOTAL	**$38,468**	**$49,558**	**$0.14**	**$0.18**	**($0.04)**

Table 8.14: Future 1 2029 Retail Residential Rate Impacts by Zone (2019 $)

[25] APC Savings are the only benefit included in the rate impact calculations.

Zone	One-Year ATRR Costs	One-Year Benefit	Rate Impact-Cost	Rate Impact Benefit	Net Impact
AEPW	$9,079	$29,110	$0.17	$0.54	($0.37)
EMDE	$760	$3,255	$0.12	$0.51	($0.39)
GMO	$1,231	$1,827	$0.13	$0.19	($0.06)
GRDA	$528	$19,905	$0.09	$3.34	($3.25)
KCPL	$2,575	$5,357	$0.18	$0.37	($0.19)
LES	$466	($422)	$0.11	($0.10)	$0.21
MIDW	$240	($2,176)	$0.09	($0.80)	$0.88
MKEC	$400	($4,683)	$0.12	($1.37)	$1.48
NPPD	$2,367	$130	$0.10	$0.01	$0.09
OKGE	$4,234	$19,213	$0.17	$0.76	($0.59)
OPPD	$1,528	($34)	$0.12	($0.00)	$0.12
SPRM	$428	$7,001	$0.13	$2.12	($1.99)
SPS	$4,448	$680	$0.14	$0.02	$0.12
SUNC	$675	($1,499)	$0.24	($0.54)	$0.79
SWPA	$171	$546	$0.17	$0.55	($0.37)
UMZ	$2,822	($1,231)	$0.12	($0.05)	$0.18
WERE	$5,028	$16,715	$0.16	$0.52	($0.37)
WFEC	$1,486	$6,077	$0.12	$0.47	($0.36)
TOTAL	**$38,468**	**$99,772**	**$0.14**	**$0.37**	**($0.23)**

Table 8.15: Future 2 2029 Retail Residential Rate Impacts by Zone (2019 $)

Zone	One-Year ATRR Costs	One-Year Benefit	Rate Impact-Cost	Rate Impact Benefit	Net Impact[26]
Arkansas	$2,474	$3,683	$0.17	$0.25	($0.08)
Iowa	$485	($51)	$0.12	($0.01)	$0.14
Kansas	$7,655	$11,828	$0.16	$0.24	($0.09)
Louisiana	$1,217	$2,324	$0.17	$0.32	($0.15)
Minnesota	$34	($4)	$0.12	($0.01)	$0.14
Missouri	$3,719	$12,129	$0.14	$0.46	($0.32)
Montana	$139	($15)	$0.12	($0.01)	$0.14
Nebraska	$4,677	$658	$0.11	$0.02	$0.09
New Mexico	$1,223	($1,765)	$0.14	($0.20)	$0.33
North Dakota	$1,121	($118)	$0.12	($0.01)	$0.14
Oklahoma	$9,590	$21,065	$0.15	$0.33	($0.18)
South Dakota	$703	($74)	$0.12	($0.01)	$0.14
Texas	$5,407	($99)	$0.15	($0.00)	$0.15
Wyoming	$25	($3)	$0.12	($0.01)	$0.14
TOTAL	**$38,468**	**$49,558**	**$0.14**	**$0.18**	**($0.04)**

Table 8.16: Future 1 2029 Retail Residential Rate Impacts by State (2019 $)

[26] State level results are based on load allocations by zone, by state. For example, 11% of Upper Missouri Zone (UMZ) load is in Nebraska, so 11% of UMZ benefits are attributed to Nebraska.

Zone	One-Year ATRR Costs	One-Year Benefit	Rate Impact-Cost	Rate Impact Benefit	Net Impact[27]
Arkansas	$2,474	$8,683	$0.17	$0.58	($0.42)
Iowa	$485	($211)	$0.12	($0.05)	$0.18
Kansas	$7,655	$11,184	$0.16	$0.23	($0.07)
Louisiana	$1,217	$3,902	$0.17	$0.54	($0.37)
Minnesota	$34	($15)	$0.12	($0.05)	$0.18
Missouri	$3,719	$14,673	$0.14	$0.56	($0.42)
Montana	$139	($61)	$0.12	($0.05)	$0.18
Nebraska	$4,677	($464)	$0.11	($0.01)	$0.12
New Mexico	$1,223	$187	$0.14	$0.02	$0.12
North Dakota	$1,121	($489)	$0.12	($0.05)	$0.18
Oklahoma	$9,590	$54,845	$0.15	$0.85	($0.70)
South Dakota	$703	($305)	$0.12	($0.05)	$0.18
Texas	$5,407	$7,855	$0.15	$0.21	($0.07)
Wyoming	$25	($11)	$0.12	($0.05)	$0.18
TOTAL	**$38,468**	**$99,772**	**$0.14**	**$0.37**	**($0.23)**

Table 8.17: Future 2 2029 Retail Residential Rate Impacts by State (2019 $)

8.3 SENSITIVITY ANALYSIS

8.3.1 METHODOLOGY

The recommended portfolio was tested under select sensitivities to understand the economic impacts associated with variations in certain model inputs. These sensitivities were not used to develop transmission projects nor filter out projects, but rather to measure the flexibility of the final consolidated portfolio in both futures (including economic, reliability and short-circuit projects) under different uncertainties. The following sensitivities were performed:

- Scoped sensitivities
    - High natural gas price
    - Low natural gas price
    - High demand
    - Low demand

[27] State level results are based on load allocations by zone, by state. For example, 11% of Upper Missouri Zone (UMZ) load is in Nebraska, so 11% of UMZ benefits are attributed to Nebraska.

- Supplemental sensitivities
    - Increased wind and solar (Future 2 only)
    - Decreased wind and solar (Future 1 only)

The demand and natural gas price sensitivities were included in the 2019 ITP Scope, however, throughout the study there have been questions about how the wind and solar assumptions would impact the potential benefit of the different portfolio. Staff performed additional sensitivities on the consolidated portfolio to provide insight into these questions.

The consolidated portfolio was tested in both futures. The economic impacts of variations in the model inputs were calculated for the simulations. One-year benefit-to-cost ratios are shown in **Error! Reference source not found.** and Figure 8.4, while 40-year benefit-to-cost ratios are shown in Figure 8.5 and Figure 8.6. The benefit-to-cost ratios are shown for all sensitivity and non-sensitivity runs. APC savings is the only benefit considered in these results. The red dashed bar in the figures represents the expected case benefit-to-cost ratio for comparison to the sensitivity case benefit-to-cost ratios.

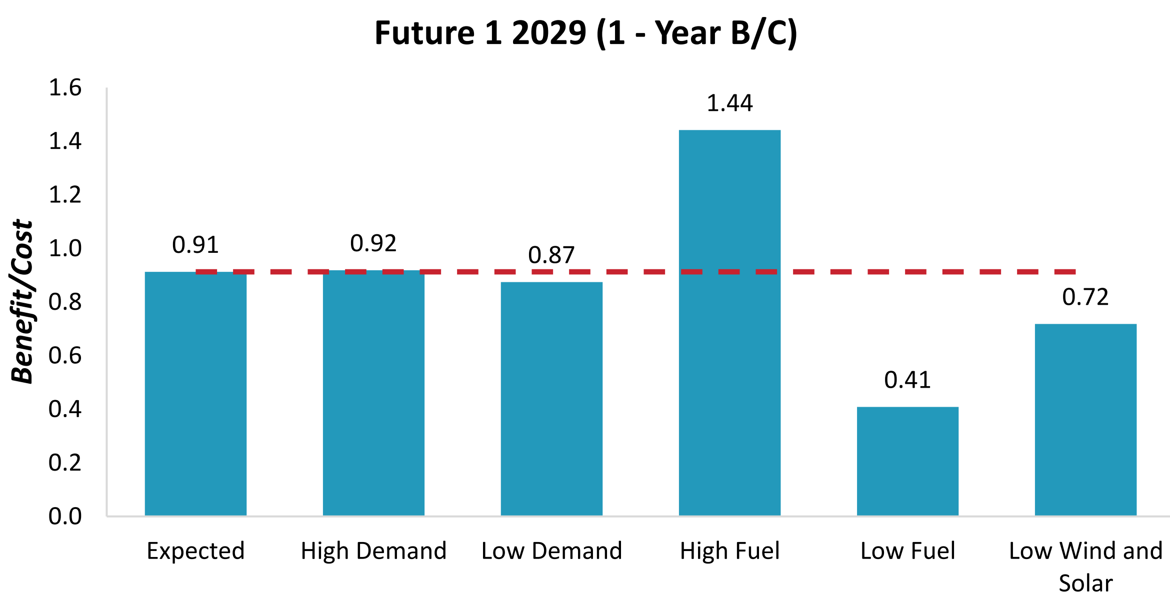


Figure 8.3: *1-Year Benefit-to-Cost Ratios for Sensitivities*

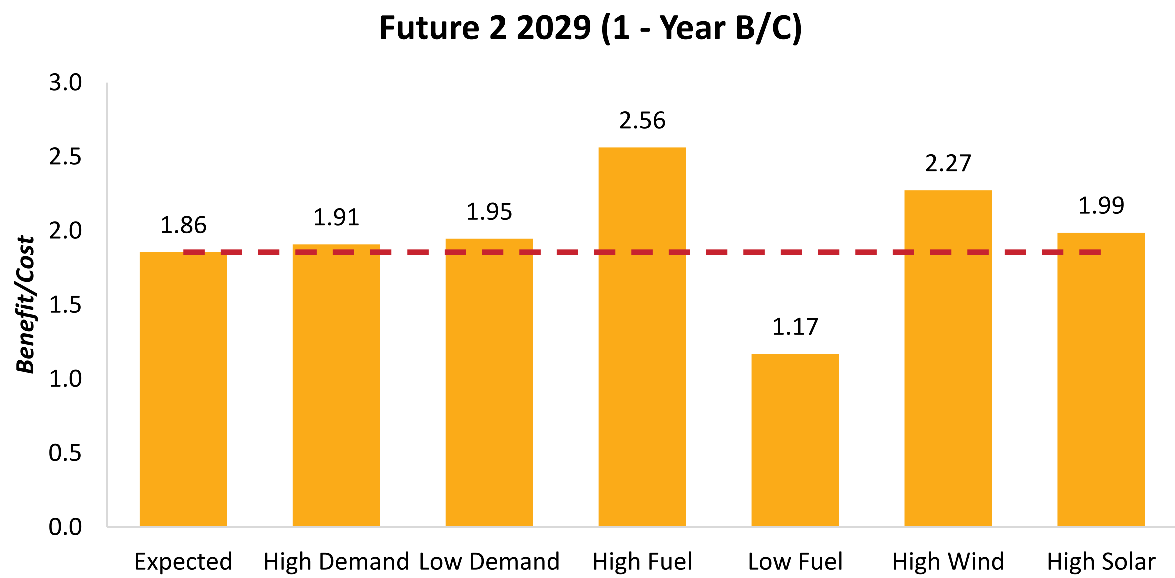


Figure 8.4: *1-Year Benefit-to-Cost Ratios for Sensitivities*

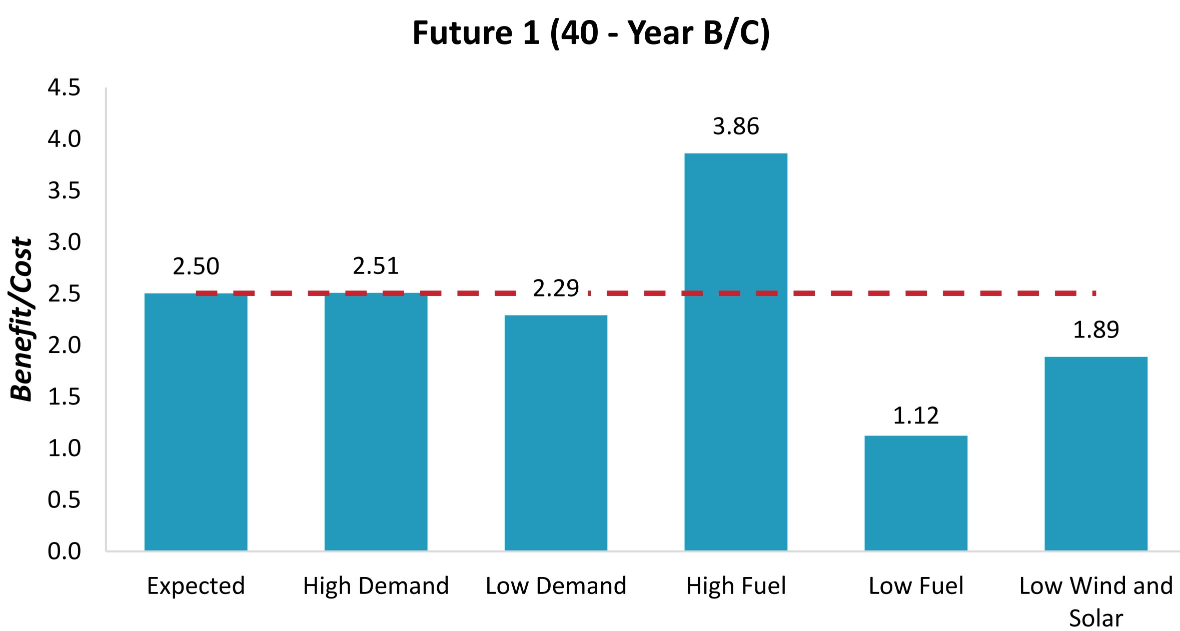


Figure 8.5: *40-Year Benefit-to-Cost Ratios for Sensitivities*

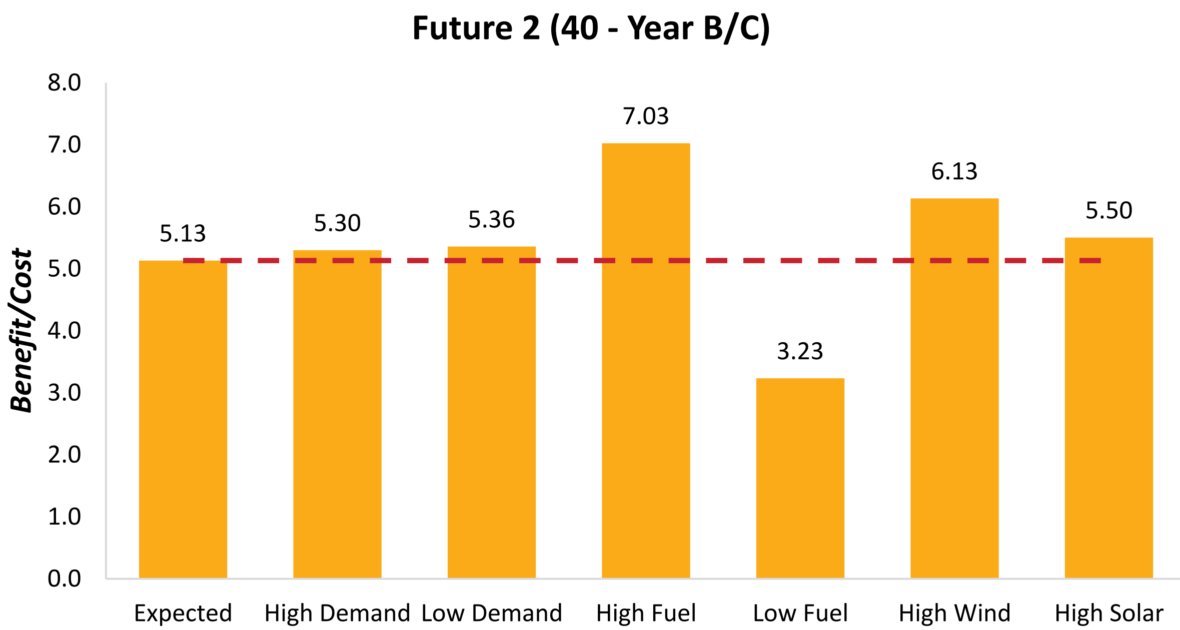


Figure 8.6: *40-Year Benefit-to-Cost Ratios for Sensitivities*

The sensitivity results show one-year benefits and costs as well as 40-year benefits and costs. The highest benefit-to-cost ratios resulted from the high gas price and increased renewable assumptions. For detailed discussion on these results, see the following sections.

8.3.2 DEMAND AND NATURAL GAS

Two confidence intervals were developed using historical market prices and demand levels from the NYMEX and FERC Form No. 714. The standard deviation of the log difference from the normal within the pricing datasets was used to provide a confidence interval. The natural gas price sensitivities had a 95% confidence interval (1.96 standard deviations) in positive and negative directions, while the demand sensitivities had a 67% confidence interval (1 standard deviation) in positive and negative directions.

The resulting assumptions are shown in Figure 8.7 and Table 8.18.

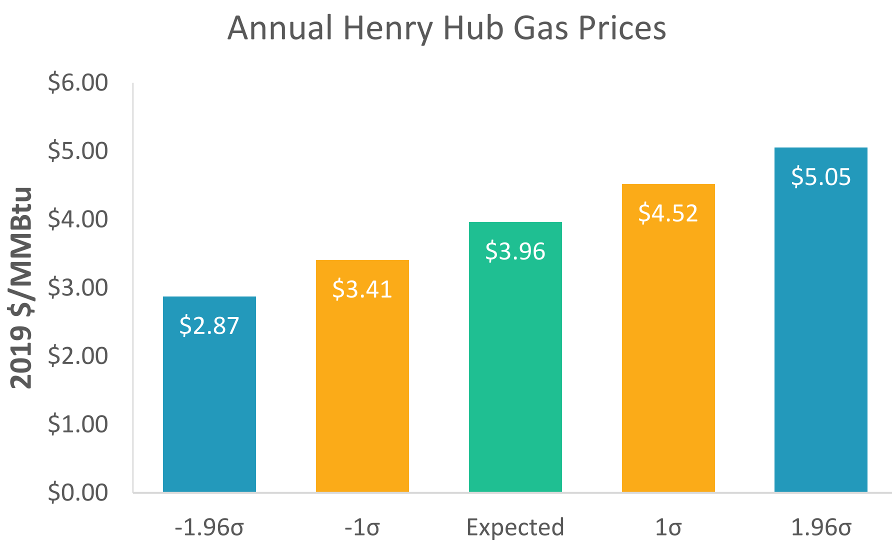


Figure 8.7: *Annual Henry Hub Natural Gas Price Values*

Sensitivity	2029 Annual Energy[28]	2029 Natural Gas Price ($/MMBtu)[29]
Expected Case	No change	No change
High Demand	7.4% Increase	No change
Low Demand	7.4% Decrease	No change
High Natural Gas	No change	$1.39 Increase
Low Natural Gas	No change	$1.39 Decrease

Table 8.18: Natural Gas and Demand Changes (2029)

The change in peak demand and energy shown in Table 8.18 reflects the SPP regional average volatility based on historical data. The 7.4% increase and decrease is the average deviation from the projected 2029 load forecasts developed by the MDWG and reviewed by the ESWG. They were implemented on the load company level. For companies without available data, the SPP regional average confidence interval was used.

These high and low values were included as inputs to the base models of each future with and without the recommended portfolio. The results of the demand and natural gas sensitivities for one-year APC benefit are reflected in Figure 8.8 and Figure 8.9. The 40-year APC benefit for these sensitivities are reflected in Figure 8.10 and Figure 8.11.

An increase in demand creates an increase in congestion on the SPP system, resulting in higher congestion costs for the portfolios to mitigate, thus increasing the benefit. The opposite is true for the low demand case in Future 1. However, the low demand in Future 2 shows higher benefit than the expected case. The fundamental driver of the higher APC benefit observed under low demand in Future 2 is increased congestion on flowgates driven by wind generators; as wind production remains constant while

[28] SPP Regional
[29] Henry Hub 2029 average annual data

demand decreases, the congestion costs are spread over less load. This means in certain cases there is a greater economic opportunity under low demand for transmission projects targeting congestion caused by wind generation.

An increase in gas prices has a similar result as an increase in demand, but also reflects an increase in the overall price of energy while causing a similar increase in congestion. The high natural gas sensitivity shows the portfolio's ability to reduce overall energy costs by relieving system congestion and allowing for a more economical generation dispatch. This is the same effect of portfolio performance in the expected case, but amplified by the increase in energy prices, thus showing more benefit. The low natural gas sensitivity has the opposite effect.

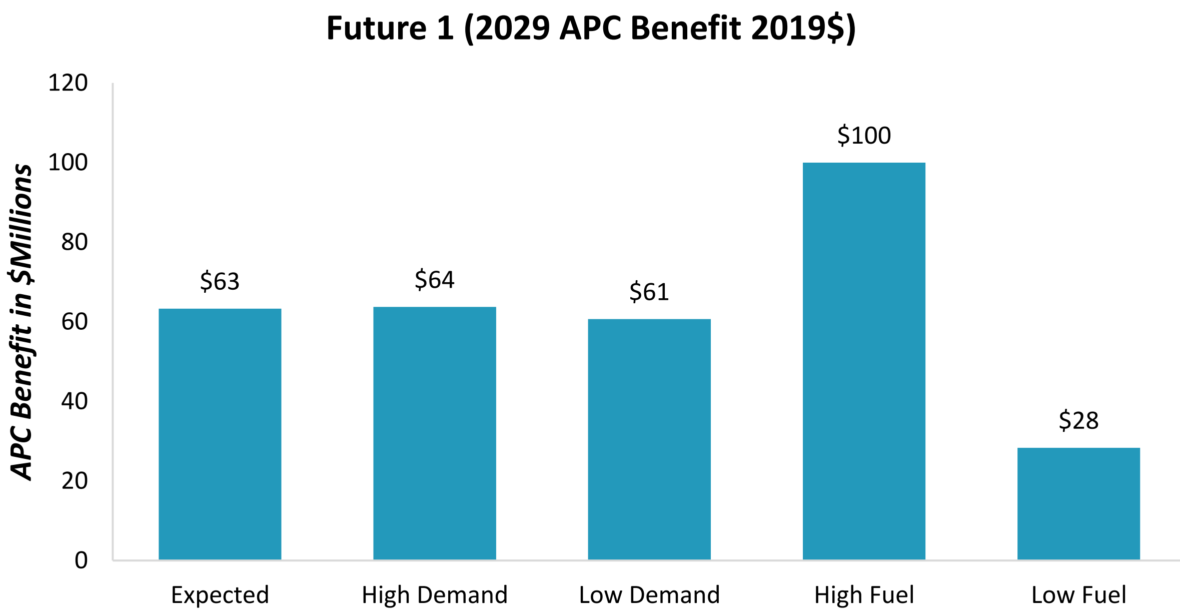


Figure 8.8: *1-Year Benefits of Future 1 Portfolio for Demand and Natural Gas Sensitivities*

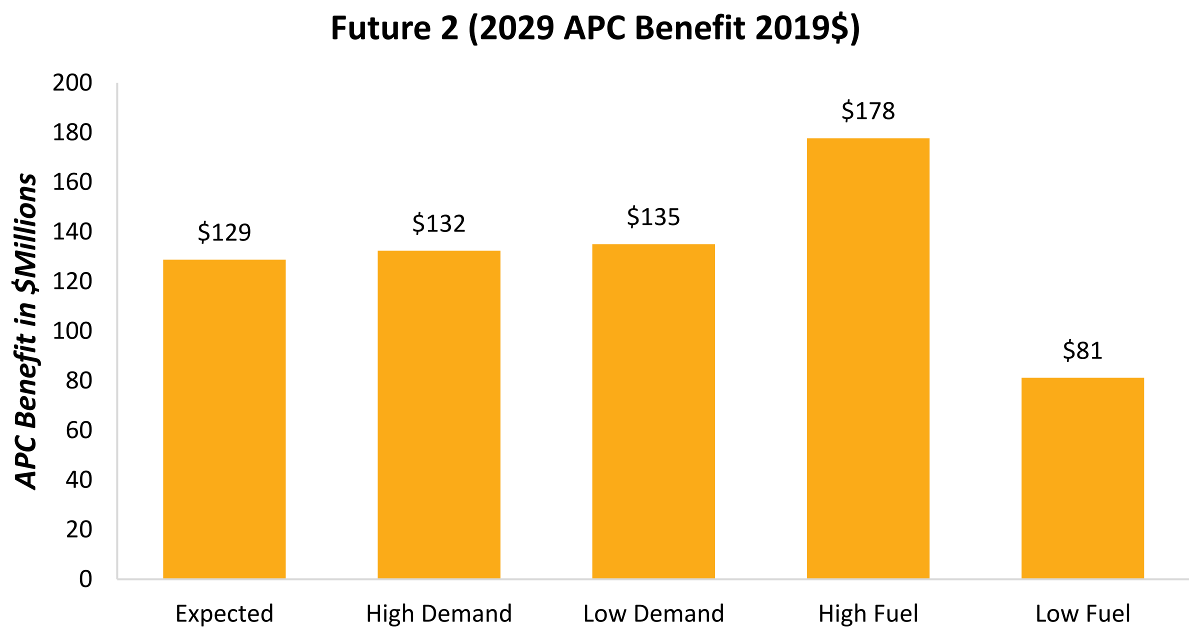


Figure 8.9: 1-Year Benefits of Future 2 Portfolio for Demand and Natural Gas Sensitivities

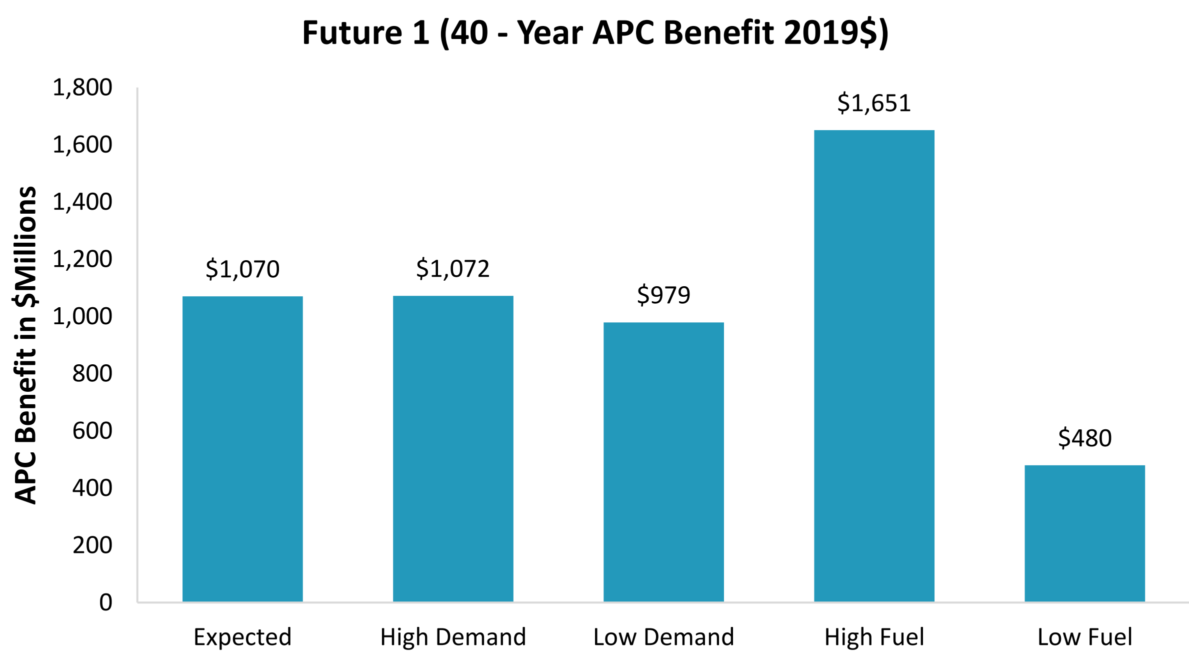


Figure 8.10*: 40-Year Benefits of Future 1 Portfolio for Demand and Natural Gas Sensitivities*

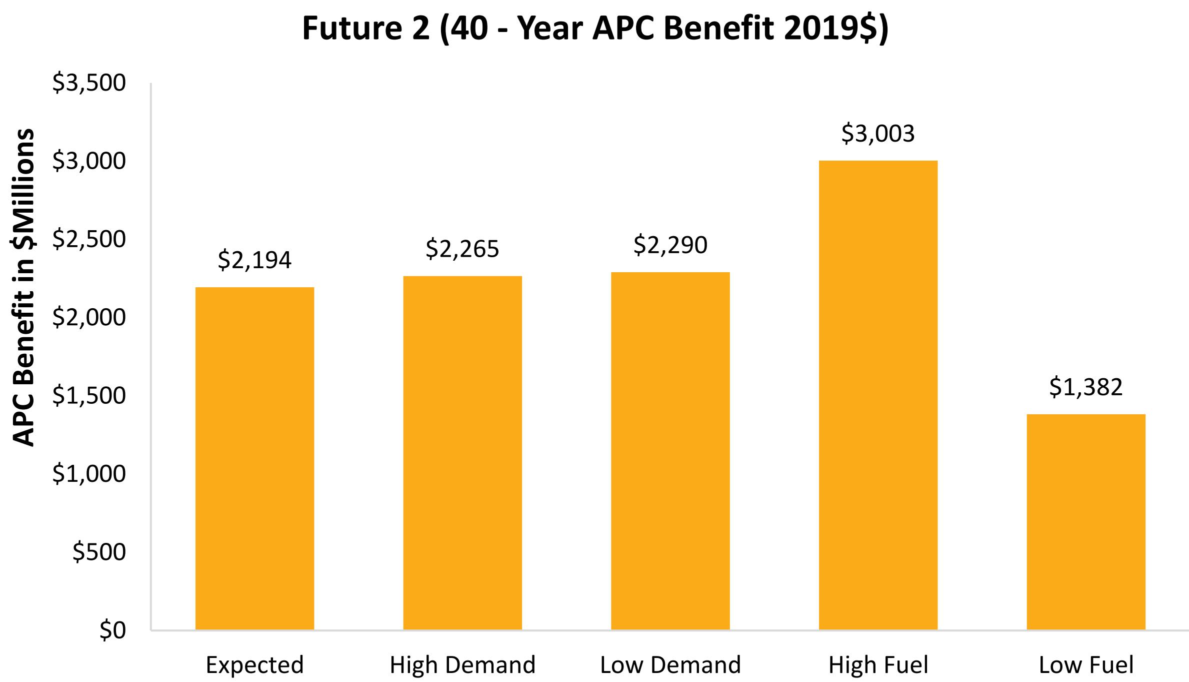


Figure 8.11*: 40-Year Benefits of Future 2 Portfolio for Demand and Natural Gas Sensitivities*

8.3.3 INCREASED RENEWABLES

The 2019 ITP renewable energy forecast in Future 2 projects an increase in wind and solar additions on the SPP system over the next 10 years. During the course of the ITP assessment, discussions occurred which questioned if the renewable amounts were conservative. As a result, a wind and solar sensitivity was conducted to test the portfolio's performance under higher wind and solar conditions. In this sensitivity (Future 2 only), wind and solar were scaled up an additional 3 GW from projected amounts. This additional wind and solar was added to each existing capacity site in the base case assumptions on a pro rata basis. APC results of this increased wind are shown in Figure 8.12 and Figure 8.13.

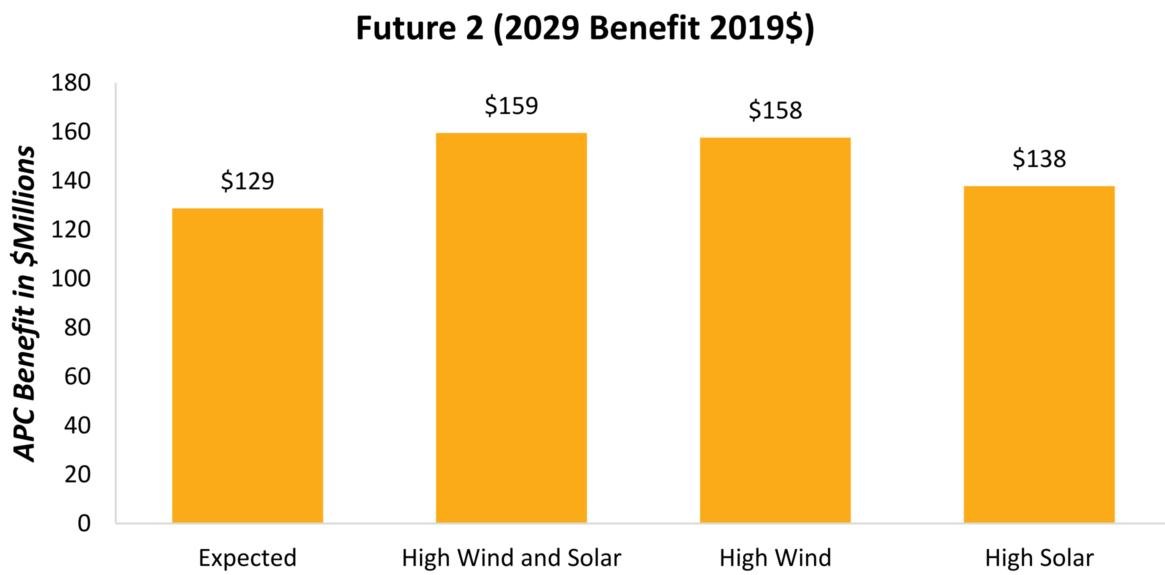


Figure 8.12: 1-Year Benefits of Future 2 Portfolio for Increased Renewables Sensitivity

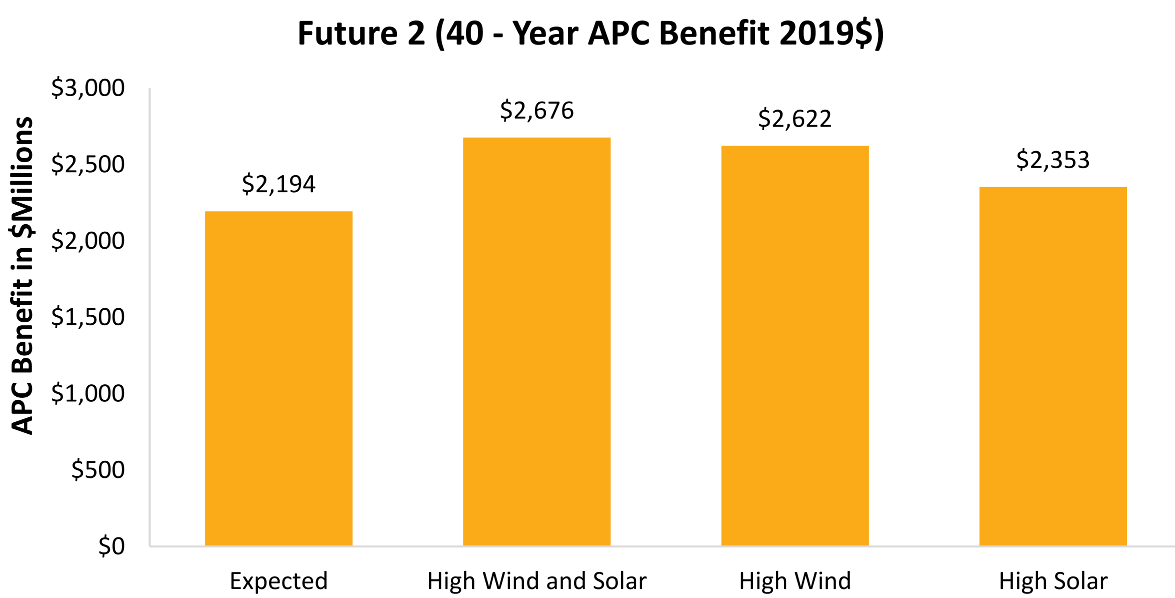


Figure 8.13: 40-Year Benefits of Future 2 Portfolio for Increased Renewables Sensitivity

Testing the portfolio against additional renewables in Future 2 showed an increase in APC benefit. This influx of additional energy increases congestion in the base cases, leaving more congestion to be addressed by the project portfolio. The increase in benefit for both portfolios confirms that renewables would be facilitated by these specific sets of projects. See Table 8.14 and Table 8.15 for the total wind and solar delivered and curtailed under the additional wind and solar scenarios compared to the base scenarios.

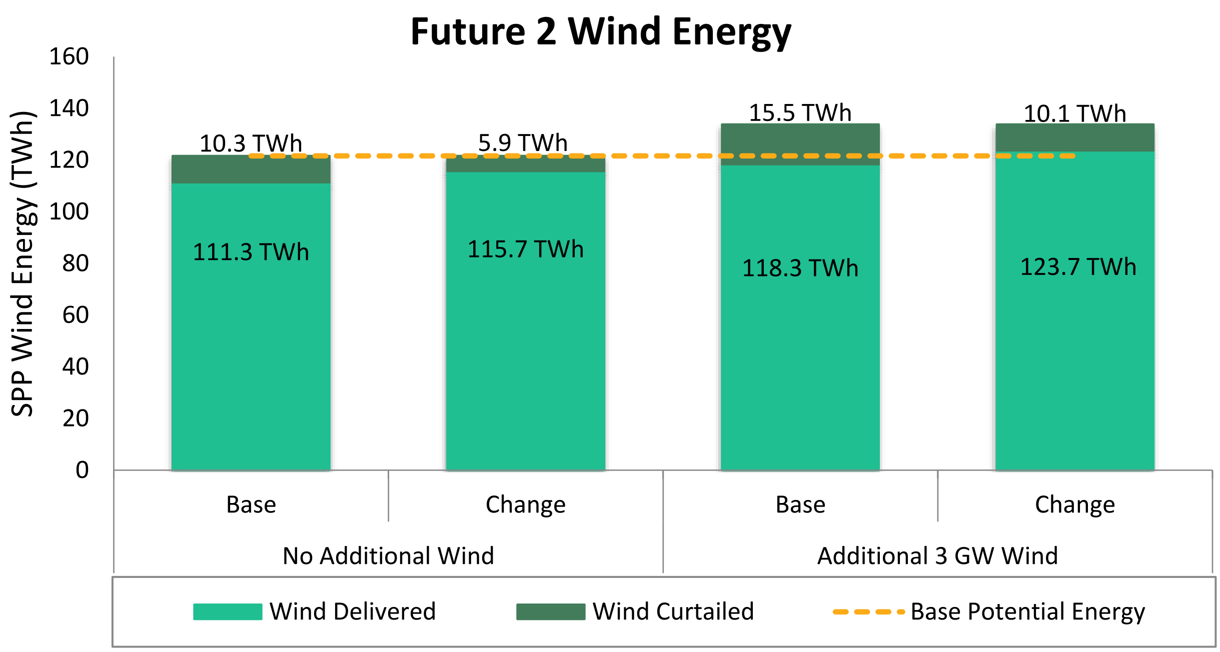


Figure 8.14: SPP Annual Wind Energy for Future 2 Portfolio (2029)

Although more energy is curtailed under the additional renewable sensitivity, more wind energy is delivered overall. The percentage of curtailments to the total potential energy roughly stays the same. The majority of energy from the wind additions is able to be delivered, affirming wind facilitation.

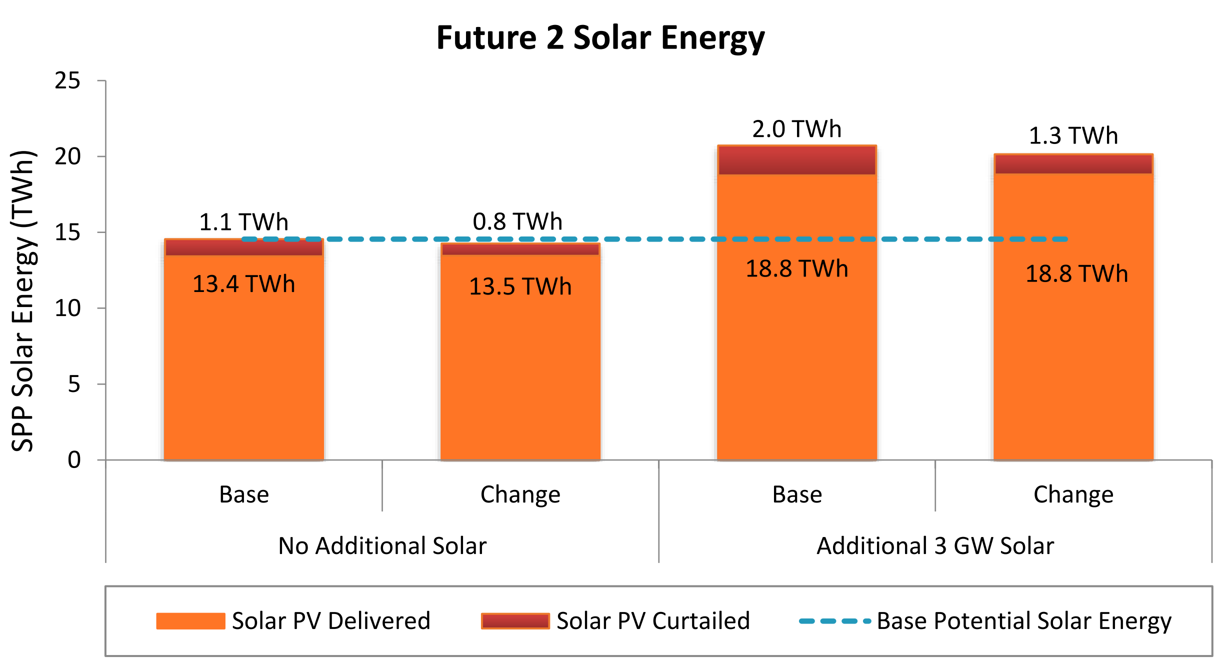


Figure 8.15: Future 2 Portfolio Solar Energy (2029)

8.3.4 DECREASED RENEWABLES

The 2019 ITP renewable energy forecast in Future 1 projects a modest increase in wind additions on the SPP system over the next 10 years. In order to understand the performance of the portfolio under the currently installed renewables, a low wind and solar sensitivity was conducted to test the portfolio's performance. In this sensitivity (Future 1 only), wind and solar are scaled down at projected sites using currently installed amounts on the SPP system of 21.5 GW of wind and 232.9 MW of solar. Wind and solar was decreased at each projected capacity site in the expected case assumptions on a pro rata basis. APC results of the decreased wind and solar are shown in Figure 8.16 and Figure 8.17.

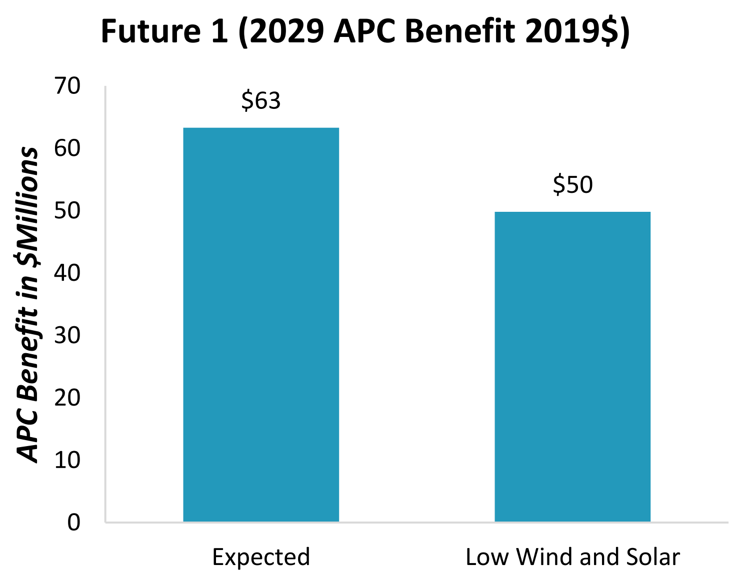


Figure 8.16: 1-Year Benefits of Future 1 Portfolio for Decreased Wind & Solar Sensitivity

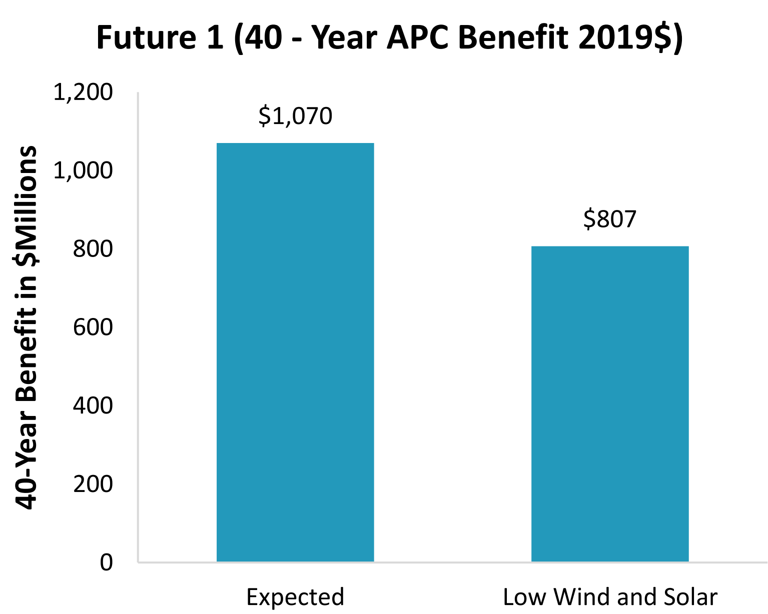


Figure 8.17: 40-Year Benefits of Future 1 Portfolio for Decreased Wind & Solar Sensitivity

Testing the scaled down renewables on Future 1 showed a decrease in APC benefit. The reduction of energy decreases congestion in the base cases leaving less congestion to be addressed by the portfolio of projects. See Figure 8.18 for the total wind and solar reduced and curtailed under the decreased wind and solar scenarios compared to the base scenarios. There was no curtailment for solar in the low renewables case; thus, Figure 8.18 does not show data for curtailed energy.

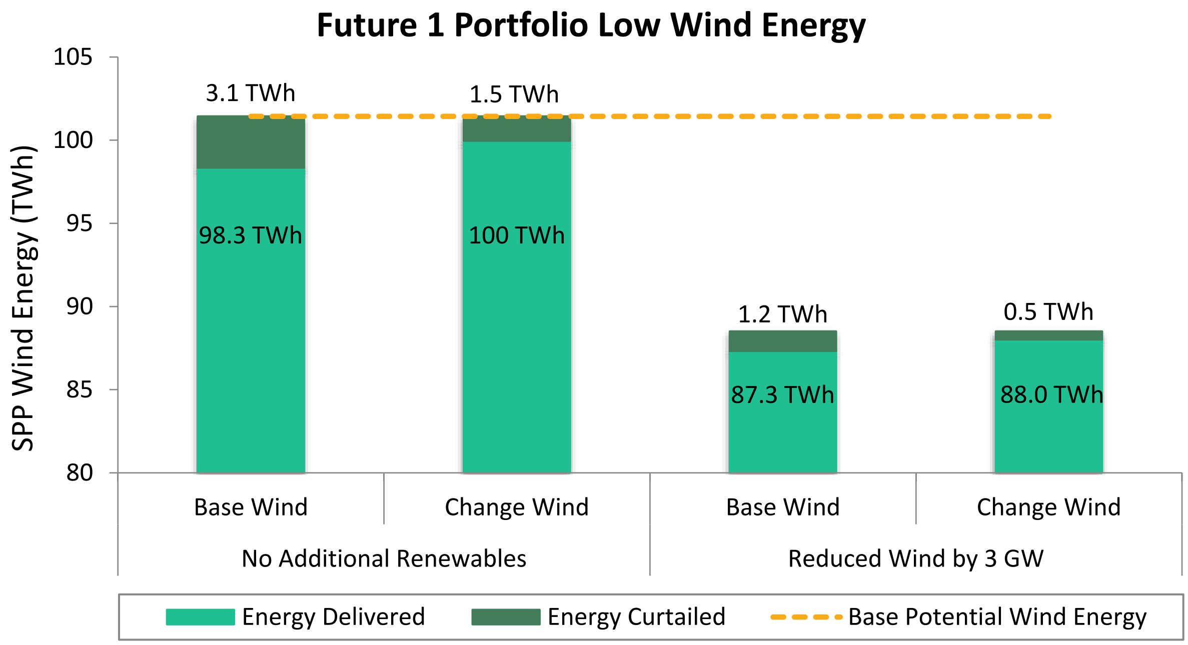


Figure 8.18: SPP Annual Wind Energy for Future 1 Portfolio (2029)

8.4 VOLTAGE STABILITY ASSESSMENT

A voltage stability assessment was conducted with the recommended portfolio using Future 1 and 2 market powerflow models to assess the transfer limit (GW) from renewables in SPP to conventional thermal generation in SPP, and from renewables in SPP to conventional thermal generation in external areas.[30] The assessment was performed to determine whether the generation dispatch with the recommended portfolios adversely impacts system voltage stability. The assessment was intentionally scoped to determine how the planned system performs under high renewable dispatch, given the projected renewable amounts assumed for the 2019 ITP assessment.

The planned system supports the future-specific renewable generation dispatches observed in the reliability hours after modeling the consolidated portfolio, reaching either minimum internal conventional thermal generation levels or thermal limits prior to reaching voltage stability limits. However, the results illustrate previously known limits of the planned system that will need to be considered further in future planning assessments when making project recommendation decisions. [31]

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[30] See TWG 11/30/2017 meeting minutes and attachments for the TWG-approved 2019 ITP Voltage Stability Scope:

[31] Specifically, 345 kV contingencies in southwestern, south-central, and southeastern Oklahoma

8.4.1 METHODOLOGY

To determine the amount of generation transfer that could be accommodated by the planned system, generation in the source zone was increased and generation in the sink zone was decreased. Table 8.19 identifies the transfer zones and boundaries.

Transfer Zones	Zone Boundaries
SPP renewables	SPP conventional thermal generation
SPP renewables	First Tier and Second Tier conventional thermal generation

Table 8.19: Generation Zones

Table 8.20 shows the transfers that were performed on the 2029 light load and 2029 summer models by scaling both on-line and off-line renewables from the source zone and scaling down the sink zone. Utility scale solar was not included in the source zone for the 2029 light load model due to the reliability hour being identified as 4 a.m.

Model	Source Zone	Sink Zone
2029 Light Load	SPP renewables (Wind)	SPP conventional thermal generation
2029 Light Load	SPP renewables (Wind)	SPP conventional thermal generation
2029 Summer	SPP renewables (Wind and Utility Scale Solar)	First Tier and Second Tier conventional thermal generation
2029 Summer	SPP renewables (Wind and Utility Scale Solar)	First Tier and Second Tier conventional thermal generation

Table 8.20: Transfers by Model

Single contingencies (N-1) for all SPP branches, transformers, and ties equal to or greater than 345 kV were analyzed. SPP and first-tier 100 kV and above facilities were monitored for voltage and thermal violations. The initial condition for each model was the source zone sum of real power generation output (MW). The maximum source zone transfer capability was the real power maximum generation (Pmax). The transfers were performed on each model in 200 MW steps until voltage collapse occurred in the pre-contingency and post-contingency (N-1, 345 kV and 500 kV facilities) conditions. The last stable transfer was then continued in increments of 10 MW to the VSL. Each future was evaluated for increasing generation transfer amounts to determine different voltage collapse points of the transmission system. Source and sink generation was scaled on a pro-rata basis to reach the pre-contingency maximum power transfer limit, or VSL. Multiple transfer limits were determined based on the worst N-1 contingency and independently evaluating the next worst contingency to determine the top five post-contingency VSL.

8.4.2 SUMMARY

Table 8.21 shows a summary of the voltage stability assessment limits by future, model and transfer path. The table includes the transfer path, source and sink generation pre-transfer levels, critical contingency, post transfer level when VSL is reached, incremental transfer limit amount, and whether or not thermal overloads occur prior to voltage collapse. The table shows in all instances either minimum internal conventional thermal generation levels or when a thermal limit is reached prior to the VSL.

Transfer Source -->Sink	Initial Source (GW)	Initial Sink (GW)	Event	VSL Source (GW)	VSL Sink (GW)	Transfer (GW)	Thermal Overloads Prior to Voltage Collapse
Future 1: 2029 Light Load							
Wind -->Internal	15.7	6.8	Reached Minimum Sink	16.5	6.1	0.8	N/A
Wind -->External Thermal	15.7	19.1	Terry Road-Sunnyside 345 kV	17.4	17.7	1.7	Yes
"	15.7	19.1	Chisholm-Gracemont 345 kV (Tap at RP2POI06)	17.8	17.5	2.1	Yes
"	15.7	19.1	Cimarron-Draper 345 kV	18.8	16.7	3.1	Yes
"	15.7	19.1	Sunnyside-Hugo 345 kV	18.8	16.7	3.1	Yes
"	15.7	19.1	Minco-Cimarron 345 kV	18.8	16.7	3.1	Yes
Future 1: 2029 Summer Peak							
Solar & Wind -->Internal	5.5	42.0	Reached Maximum Source	30.1	18.5	24.5	Yes
Solar & Wind -->External	5.5	87.2	Oklaunion-Lawton Eastside 345 kV	16.8	77.6	11.2	Yes
"	5.5	87.2	Mount Olive-Layfield 500kV	17.4	77.2	11.8	Yes
"	5.5	87.2	Holt-S3458 345 kV	17.6	77.0	12.0	Yes
"	5.5	87.2	Tuco-Oklaunion 345 kV	17.8	76.9	12.2	Yes
"	5.5	87.2	Muskogee-Fort Smith 345 kV	17.8	76.9	12.2	Yes
Future 2: 2029 Light Load							
Wind -->Internal	18.2	5.7	Reached Minimum Sink	18.9	5.1	0.7	N/A
Wind -->External	18.2	21.1	Crossroads-Eddy County 345 kV	20.6	19.4	2.4	Yes
"	18.2	21.1	Terry Road-Sunnyside 345 kV	21.0	19.1	2.8	Yes
"	18.2	21.1	Pittsburg-Valliant 345 kV	21.0	19.1	2.8	Yes
"	18.2	21.1	Sunnyside-Hugo 345 kV	21.6	18.7	3.4	Yes

Transfer Source -->Sink	Initial Source (GW)	Initial Sink (GW)	Event	VSL Source (GW)	VSL Sink (GW)	Transfer (GW)	Thermal Overloads Prior to Voltage Collapse
"	18.2	21.1	Fort Smith-ANO 500kV	21.6	18.7	3.4	Yes
Future 2: 2029 Summer Peak							
Solar & Wind -->Internal	16.1	33.7	Mingo-Red Willow 345 kV	28.7	21.9	12.6	Yes
"	16.1	33.7	Setab-Mingo 345 kV	28.7	21.9	12.6	Yes
"	16.1	33.7	La Cygne-Stillwell 345 kV	28.7	21.9	12.6	Yes
Future 2: 2029 Summer Peak *(continued)*							
"	16.1	33.7	Wichita-Reno 345 kV	28.9	21.7	12.8	Yes
"	16.1	33.7	JEC-Hoyt 345 kV	28.9	21.7	12.8	Yes
Solar & Wind -->External	16.1	82.7	JEC-Hoyt 345 kV	20.3	78.9	4.2	Yes
"	16.1	82.7	La Cygne-Stillwell 345 kV	21.1	78.3	5.0	Yes
"	16.1	82.7	Hoyt-Stranger 345 kV	21.5	77.9	5.4	Yes
"	16.1	82.7	Jasper-Morgan 345 kV	21.5	77.9	5.4	Yes
"	16.1	82.7	La Cygne-West Gardner 345 kV	21.7	77.8	5.6	Yes

Table 8.21: Post-Contingency Voltage Stability Transfer Limit Summary

Table 8.22 shows a summary of the voltage stability assessment limits and thermal limits by future, model and transfer path. The table includes the transfer path, total renewable capacity, post transfer level when thermal violations and VSLs are reached, and a comment summarizing either the minimum internal conventional thermal generation levels or when a thermal limit is reached prior to the VSL.

Transfer Source-->Sink	Total Renewable Capacity (GW)	VSL Limit (GW)	Thermal Limit (GW)	Comment
Future 1: 2029 Light Load				
Wind-->Internal	**24.6**	N/A	N/A	Reached Sink Minimum
Wind-->External	**24.6**	17.4	16.9	Thermal Issues prior to Voltage Collapse
Future 1: 2029 Summer Peak				
Solar & Wind -->Internal	**29.6**	30.1	7.3	No Voltage Collapse
Solar & Wind -->External	**29.6**	16.8	9.0	Thermal Issues prior to Voltage Collapse
Future 2: 2029 Light Load				
Wind-->Internal	**30**	N/A	N/A	Reached Sink Minimum

Transfer Source-->Sink	Total Renewable Capacity (GW)	VSL Limit (GW)	Thermal Limit (GW)	Comment
Wind-->External	**30**	20.6	20.4	Thermal Issues prior to Voltage Collapse
Future 2: 2029 Summer Peak				
Solar & Wind -->Internal	**37**	28.7	16.1	Thermal Issues prior to Voltage Collapse
Solar & Wind -->External	**37**	20.3	16.1	Thermal Issues prior to Voltage Collapse

Table 8.22: Voltage Stability Results Summary

8.4.3 CONCLUSION

The analysis demonstrates the planned system does not reach a VSL prior to system thermal limits; therefore, the potential benefits attributed to the consolidated portfolio are validated. Voltage collapse occurs at renewable levels less than the projected renewable capacity amounts. However, thermal issues (*i.e.*, causing renewable curtailments) occur prior to voltage collapse when thermal issues are captured in the market economic model as congestion. The APC benefit of the consolidated portfolio generally derives from relieving congestion on thermal issues. Voltage collapse occurs at aggregate renewable levels greater than what is observed in the market economic model reliability hours after modeling the consolidated portfolio.

8.5 FINAL RELIABILITY ASSESSMENT

8.5.1 METHODOLOGY

All projects in the 2019 ITP recommended portfolio and model adjustments identified during solution development were incorporated into the base reliability, short-circuit, and select seasons of the market powerflow models (year 10 peak and off-peak, Futures 1 and 2). The market powerflow models were rebuilt following the DC-to-AC conversion process described in Section 2.3.1 of the ITP Manual. A contingency analysis of equivalent scope to the analysis described in Sections 4.2.1 and 4.2.2 of the ITP Manual was performed to determine if the selected projects caused any new reliability violations.

8.5.1.1 Short-Circuit Model

A proxy automatic sequencing fault calculation (ASCC) short-circuit analysis was performed on the 2019 ITP Year 2 Summer Maximum Fault Current Model to find percent increases in fault currents in relation to the base case model on which the needs assessment was performed. All consolidated portfolio projects expected to alter or need zero sequence data were added to the model regardless of their in-service dates. After performing this analysis, it was found that 58 of the 9,610 buses monitored experienced a 5% increase in fault current. Only three of the 58 buses appeared to exceed common breaker duty ratings of 20kA and 40kA. The subsequent short-circuit analysis performed next cycle will confirm whether or not the duty ratings are exceeded given the latest modeling assumptions.

8.5.2 SUMMARY

8.5.2.1 Base Reliability Powerflow Models

The resulting thermal and voltage violations were solved or marked invalid through methods such as reactive device setting adjustments, model updates, identification of invalid contingencies, non-load-serving buses, and facilities not under SPP's functional control.

8.5.2.2 Market Powerflow Models

A portion of the resulting thermal and voltage violations caused by the 2019 ITP consolidated portfolio were solved or marked invalid through the same methods utilized for the base reliability powerflow models. The remaining thermal overload violations were given additional review and not considered to be new reliability violations based on ITP Manual Section 4.2.5 violation filtering criteria. New voltage violations were observed at several monitored facilities in the south SPS area for loss of the Crossroads-Eddy County 345 kV line; no solutions will be developed for these violations. These facilities will be monitored in the initial assessments of the 2020 ITP for continued issues.

8.5.2.3 Short-Circuit Model

The final reliability assessment for the short-circuit model did not show any new fault-interrupting equipment to have its duty ratings exceeded by the maximum available fault current (potential violation) due to the addition of the consolidated portfolio.

8.5.3 CONCLUSION

The final reliability assessment showed no new reliability violations caused by the 2019 ITP recommended portfolio that require additional project recommendations in this ITP assessment.

9 NTC RECOMMENDATIONS

SPP staff makes Notification to Consruct (NTC) recommendations for projects included in the consolidated portfolio based upon results from the staging process and SPP Business Practice 7060. If financial expenditure is required within four years from board approval, the project is recommended for an NTC or NTC-C (Notification to Construct with Conditions). To determine the date when financial expenditure is required, the project's lead time is subtracted from its need date. Expected lead times for transmission projects are determined using historical data on construction timelines from SPP's Project Tracking process. NTC-Cs are issued for projects with an operating voltage greater than 100 kV and a study cost estimate greater than $20 million.

One exception to this process for the 2019 ITP is the Butler 138 kV phase-shifting transformer. Although this upgrade proved to be cost-effective during the analysis, no NTC is recommended. A qualitative assessment of the Butler 138 kV phase-shifting transformer revealed it may not be the optimal long-term solution.

The Butler-Altoona 138 kV line is 70 miles, spanning from northeast Wichita to a rural area north of Independence, Kansas. This line is one of the oldest and lowest rated in SPP, as compared to other 138 kV facilities. The Butler 138 kV phase-shifting transformer was expected to redirect flows on the Butler-Altoona 138 kV line to other higher capacity facilities. However, definitive long-term plans for rehabilitation of the facility have yet to be determined, suggesting additional analysis is necessary in future planning studies.

Table 9.1 below shows SPP's NTC recommendations when considering staging results, expected lead times, and the resulting financial commitment date. For the reasons indicated above, the Butler 138 kV phase-shifting is not recommended to receive an NTC.

Description	Need Date	Lead Time (months)	Financial Expenditure Date	NTC?
Replace one breaker at Craig 161 kV	6/1/2021	18	12/1/2019	NTC
Replace two breakers at Leeds 161 kV	6/1/2021	18	12/1/2019	NTC
Replace two breakers at Midtown 161 kV	6/1/2021	18	12/1/2019	NTC
Replace four breakers at Southtown 161 kV	6/1/2021	18	12/1/2019	NTC
Replace one breaker at Moore 13.8 kV tertiary bus	6/1/2021	18	12/1/2019	NTC
Replace two breakers at Hastings 115 kV	6/1/2021	18	12/1/2019	NTC
Replace five breakers at Canaday 115 kV	6/1/2021	18	12/1/2019	NTC
Replace two breakers at Westmoore 138 kV	6/1/2021	18	12/1/2019	NTC
Replace three breakers at Santa Fe 138 kV	6/1/2021	18	12/1/2019	NTC

Description	Need Date	Lead Time (months)	Financial Expenditure Date	NTC?
Replace one breaker at Carlsbad Interchange 115 kV	6/1/2021	18	12/1/2019	NTC
Replace three breakers at Denver City North and South 115 kV	6/1/2021	18	12/1/2019	NTC
Replace three breakers at Hale County Interchange 115 kV	6/1/2021	18	12/1/2019	NTC
Replace one breaker at Washita 69 kV	6/1/2021	18	12/1/2019	NTC
Replace 12 breakers at Mooreland 138/69 kV	6/1/2021	18	12/1/2019	NTC
Replace 21 breakers at Riverside Station 138 kV	6/1/2021	18	12/1/2019	NTC
Replace eight breakers at Southwestern Station 138 kV	6/1/2021	18	12/1/2019	NTC
Replace three breakers at Anadarko 138 kV	6/1/2021	18	12/1/2019	NTC
Cleo Corner-Cleo Switch 69 kV terminal equipment	6/1/2022	18	12/1/2020	NTC
Deaf Smith-Plant X 230 kV terminal equipment	4/1/2029	18	10/1/2027	No
Bushland-Deaf Smith 230 kV terminal equipment	4/1/2026	18	10/1/2024	No
Potter-Newhart 230 kV terminal equipment	4/1/2028	18	10/1/2026	No
Getty-Skelly 69 kV terminal equipment	4/1/2021	18	10/1/2019	NTC
Marshall-Smittyville-Bailey-Seneca 115 kV rebuild	4/1/2021	30	10/1/2018	NTC
Pryor Junction 138/115 kV transformer	6/1/2021	24	6/1/2019	NTC
Tulsa SE-21st Street Tap 138 kV rebuild	6/1/2021	24	6/1/2019	NTC
Tulsa SE-S. Hudson 138 kV rebuild	6/1/2021	24	6/1/2019	NTC
Moore-RB–S&S 115 kV terminal equipment	6/1/2026	18	12/1/2024	No
Carlisle-LP Doud 115 kV terminal equipment	6/1/2026	18	12/1/2024	No
Lubbock-Jones 230 kV circuit 1 terminal equipment	6/1/2029	18	12/1/2027	No
Lubbock-Jones 230 kV circuit 2 terminal equipment	6/1/2029	18	12/1/2027	No
Plains-Yoakum 115 kV terminal equipment	6/1/2029	18	12/1/2027	NO
Firth 15 MVAR 115 kV capacitor bank	4/1/2021	24	4/1/2019	NTC
Rocky Point-Marietta 69 kV terminal equipment	12/1/2021	18	6/1/2020	NTC
Gypsum 12 MVAR 69 kV capacitor bank	6/1/2021	24	6/1/2019	NTC

Description	Need Date	Lead Time (months)	Financial Expenditure Date	NTC?
Lawrence EC-Midland 115 kV terminal equipment	1/1/2021	18	7/1/2019	NTC
Sundown-Amoco 115 kV terminal equipment	1/1/2023	18	7/1/2021	NTC
Spearman-Hansford 115 kV rebuild	1/1/2021	18	7/1/2019	NTC
Kingfisher-East Kingfisher Tap 138 kV rebuild	1/1/2021	24	1/1/2019	NTC
Cimarron-Northwest-Mathewson 345 kV terminal equipment	1/1/2021	18	7/1/2019	NTC
New Sooner-Wekiwa 345 kV line, Sheffield Steel-Sand Springs 138 kV terminal equipment	1/1/2026	48	1/1/2022	NTC-C
Arnold-Ransom 115 kV terminal equipment, Pile-Scott City-Setab 115 kV terminal equipment	1/1/2025	18	7/1/2023	NTC
Gracemont-Anadarko 138 kV rebuild	1/1/2021	24	1/1/2019	NTC
New Wolf Creek-Blackberry 345 kV line, new Butler 138 kV phase shifting transformer	1/1/2026	48	1/1/2022	**Line**: NTC-C **PST**: No

Table 9.1: NTC Recommendations

10 APPENDIX

10.1 FINAL RELIABILITY ASSESSMENT – NEW VIOLATIONS

Table 10.1 lists the new voltage violations observed in the market powerflow models after performing the final reliability assessment.

Scenario	Contingency Name	Bus Number	Post-Contingent Voltage
F2 2029 LL	Crossroads-Eddy County 345 kV	AMOCO_SS 6	0.8889
F2 2029 LL	Crossroads-Eddy County 345 kV	AMOCOWASSON6	0.8365
F2 2029 LL	Crossroads-Eddy County 345 kV	YOAKUM 6	0.8414
F2 2029 LL	Crossroads-Eddy County 345 kV	YOAKUM_345	0.85
F2 2029 LL	Crossroads-Eddy County 345 kV	BRU_SUB 6	0.8386
F2 2029 LL	Crossroads-Eddy County 345 kV	OXYBRU 6	0.8386
F2 2029 LL	Crossroads-Eddy County 345 kV	XTO_MAHONEY6	0.8377
F2 2029 LL	Crossroads-Eddy County 345 kV	BENNETT 3	0.8742
F2 2029 LL	Crossroads-Eddy County 345 kV	CORTEZ 3	0.8788
F2 2029 LL	Crossroads-Eddy County 345 kV	APACHE_ROB 3	0.8788
F2 2029 LL	Crossroads-Eddy County 345 kV	ALLRED_SUB 3	0.879
F2 2029 LL	Crossroads-Eddy County 345 kV	INK_BASIN 3	0.89
F2 2029 LL	Crossroads-Eddy County 345 kV	INK_BASIN 6	0.8362
F2 2029 LL	Crossroads-Eddy County 345 kV	ALRDCRTZ_TP3	0.8801
F2 2029 LL	Crossroads-Eddy County 345 kV	XTO_CORNEL+3	0.8774
F2 2029 LL	Crossroads-Eddy County 345 kV	SHELL_C2 3	0.8723
F2 2029 LL	Crossroads-Eddy County 345 kV	ARCO_TP 3	0.8748
F2 2029 LL	Crossroads-Eddy County 345 kV	OXY_WILRD1 3	0.8736
F2 2029 LL	Crossroads-Eddy County 345 kV	ODC_TP 3	0.8741
F2 2029 LL	Crossroads-Eddy County 345 kV	ODC 3	0.872
F2 2029 LL	Crossroads-Eddy County 345 kV	SHELL_CO2 3	0.8687
F2 2029 LL	Crossroads-Eddy County 345 kV	SHELLC3_TP 3	0.8749
F2 2029 LL	Crossroads-Eddy County 345 kV	SHELLC3 3	0.8747
F2 2029 LL	Crossroads-Eddy County 345 kV	EL_PASO 3	0.8684
F2 2029 LL	Crossroads-Eddy County 345 kV	SAN_ANDS_TP3	0.8677
F2 2029 LL	Crossroads-Eddy County 345 kV	SAN_ANDRES 3	0.8651
F2 2029 LL	Crossroads-Eddy County 345 kV	DENVER_N 3	0.8687
F2 2029 LL	Crossroads-Eddy County 345 kV	DENVER_S 3	0.8687
F2 2029 LL	Crossroads-Eddy County 345 kV	MUSTANG 3	0.8673

Scenario	Contingency Name	Bus Number	Post-Contingent Voltage
F2 2029 LL	Crossroads-Eddy County 345 kV	MUSTANG 6	0.8357
F2 2029 LL	Crossroads-Eddy County 345 kV	GS-MUSTANG 6	0.8357
F2 2029 LL	Crossroads-Eddy County 345 kV	LG-PLSHILL 3	0.8895
F2 2029 LL	Crossroads-Eddy County 345 kV	SEAGRAVES 3	0.8853
F2 2029 LL	Crossroads-Eddy County 345 kV	DIAMONDBACK3	0.8816
F2 2029 LL	Crossroads-Eddy County 345 kV	ROZ 3	0.8757
F2 2029 LL	Crossroads-Eddy County 345 kV	AMERADA 3	0.8755
F2 2029 LL	Crossroads-Eddy County 345 kV	SULPHUR 3	0.8877
F2 2029 LL	Crossroads-Eddy County 345 kV	SEMINOLE 3	0.8768
F2 2029 LL	Crossroads-Eddy County 345 kV	SEMINOLE 6	0.8157
F2 2029 LL	Crossroads-Eddy County 345 kV	RUSSELL 3	0.8611
F2 2029 LL	Crossroads-Eddy County 345 kV	HIGGEAST 3	0.862
F2 2029 LL	Crossroads-Eddy County 345 kV	LE-KCM 2	0.8534
F2 2029 LL	Crossroads-Eddy County 345 kV	AM_FRAC 3	0.8597
F2 2029 LL	Crossroads-Eddy County 345 kV	GAINES 3	0.8644
F2 2029 LL	Crossroads-Eddy County 345 kV	OXY_WSTSEM 3	0.8634
F2 2029 LL	Crossroads-Eddy County 345 kV	OXY_WSEM_TP3	0.8639
F2 2029 LL	Crossroads-Eddy County 345 kV	DOSS 3	0.8675
F2 2029 LL	Crossroads-Eddy County 345 kV	LEGACY 3	0.8627
F2 2029 LL	Crossroads-Eddy County 345 kV	MAPCO 3	0.8597
F2 2029 LL	Crossroads-Eddy County 345 kV	JOHNSON_DRW3	0.86
F2 2029 LL	Crossroads-Eddy County 345 kV	HIGG 3	0.862
F2 2029 LL	Crossroads-Eddy County 345 kV	FLANNAGAN 2	0.8998
F2 2029 LL	Crossroads-Eddy County 345 kV	LG-FLOREY +2	0.8998
F2 2029 LL	Crossroads-Eddy County 345 kV	CUNNINHAM 3	0.8836
F2 2029 LL	Crossroads-Eddy County 345 kV	CUNNIGHM_N 6	0.8727
F2 2029 LL	Crossroads-Eddy County 345 kV	CUNNIGHM_S 6	0.8727
F2 2029 LL	Crossroads-Eddy County 345 kV	HOBBS_INT 3	0.8871
F2 2029 LL	Crossroads-Eddy County 345 kV	HOBBS_INT 6	0.8652
F2 2029 LL	Crossroads-Eddy County 345 kV	HOBBS_INT 7	0.8696
F2 2029 LL	Crossroads-Eddy County 345 kV	POTASH_JCT 6	0.8908
F2 2029 LL	Crossroads-Eddy County 345 kV	LE-WAITS 3	0.8877
F2 2029 LL	Crossroads-Eddy County 345 kV	LE-WEST_SUB3	0.8894
F2 2029 LL	Crossroads-Eddy County 345 kV	LE-NRTH_INT3	0.8892
F2 2029 LL	Crossroads-Eddy County 345 kV	LE-SANANDRS3	0.8809
F2 2029 LL	Crossroads-Eddy County 345 kV	BUCKEYE_TP 3	0.8814
F2 2029 LL	Crossroads-Eddy County 345 kV	MADDOXG23 3	0.8839

Scenario	Contingency Name	Bus Number	Post-Contingent Voltage
F2 2029 LL	Crossroads-Eddy County 345 kV	MADDOX 3	0.8839
F2 2029 LL	Crossroads-Eddy County 345 kV	BUCKEYE 3	0.8813
F2 2029 LL	Crossroads-Eddy County 345 kV	PEARLE 3	0.8928
F2 2029 LL	Crossroads-Eddy County 345 kV	TAYLOR 3	0.8741
F2 2029 LL	Crossroads-Eddy County 345 kV	BENSING 3	0.8727
F2 2029 LL	Crossroads-Eddy County 345 kV	MILLEN 3	0.8771
F2 2029 LL	Crossroads-Eddy County 345 kV	NE_HOBBS 3	0.8757
F2 2029 LL	Crossroads-Eddy County 345 kV	W_BENDER 3	0.8708
F2 2029 LL	Crossroads-Eddy County 345 kV	N_HOBBS 3	0.8682
F2 2029 LL	Crossroads-Eddy County 345 kV	SANGER_SW 3	0.8728
F2 2029 LL	Crossroads-Eddy County 345 kV	E_SANGER 3	0.8762
F2 2029 LL	Crossroads-Eddy County 345 kV	S_HOBBS 3	0.8858
F2 2029 LL	Crossroads-Eddy County 345 kV	OXY_S_HOBBS3	0.888
F2 2029 LL	Crossroads-Eddy County 345 kV	SW_4J44 3	0.892
F2 2029 LL	Crossroads-Eddy County 345 kV	MONUMENT 3	0.8869
F2 2029 LL	Crossroads-Eddy County 345 kV	W_HOBBS 3	0.8941
F2 2029 LL	Crossroads-Eddy County 345 kV	LEA_ROAD 3	0.897
F2 2029 LL	Crossroads-Eddy County 345 kV	OIL_CENTER 3	0.8921
F2 2029 LL	Crossroads-Eddy County 345 kV	COOPER_RNCH3	0.8868
F2 2029 LL	Crossroads-Eddy County 345 kV	MONUMNT_TP 3	0.8809
F2 2029 LL	Crossroads-Eddy County 345 kV	OXYPERMIAN 3	0.8711
F2 2029 LL	Crossroads-Eddy County 345 kV	BYRD_TP 3	0.8797
F2 2029 LL	Crossroads-Eddy County 345 kV	BYRD 3	0.878
F2 2029 LL	Crossroads-Eddy County 345 kV	ANDREWS 6	0.8634
F2 2029 LL	Crossroads-Eddy County 345 kV	GAINESGENTP6	0.8645
F2 2029 LL	Crossroads-Eddy County 345 kV	LE-TXACO_TP3	0.8811
F2 2029 LL	Crossroads-Eddy County 345 kV	LE-SW91 2	0.8558
F2 2029 LL	Crossroads-Eddy County 345 kV	LE-ANCELL 2	0.8558
F2 2029 LL	Crossroads-Eddy County 345 kV	LE-ANCEL_TP2	0.8567
F2 2029 LL	Crossroads-Eddy County 345 kV	LE-ERF 2	0.8573
F2 2029 LL	Crossroads-Eddy County 345 kV	LE-ERF 3	0.86
F2 2029 LL	Crossroads-Eddy County 345 kV	LE-GAINES 2	0.8533
F2 2029 LL	Crossroads-Eddy County 345 kV	LE-ROZ 2	0.8544
F2 2029 LL	Crossroads-Eddy County 345 kV	LE-TEXACO 3	0.8809
F2 2029 LL	Crossroads-Eddy County 345 kV	RP2POI12	0.8441

Table 10.1: Market Powerflow Model – New Voltage Violations

10.2 ITP MANUAL AND 2019 ITP SCOPE REFERENCES

Section	Description	ITP Manual Section(s)	ITP Scope Section(s)
1	**Introduction**	**1**	**1**
1.1	The ITP Assessment	1.1, 1.2, 1.6	
1.2	Report Structure	8.1	
1.3	Stakeholder Collaboration	1.3.1, 1.4	
1.3.1	Planning Summits	6.1	
2	**Model Development**	**2**	**2**
2.1	Base Reliability Model	2.1	
2.2	Market Economic Model	2.2	
2.3	Market Powerflow Model	2.3	
3	**Benchmarking**	**3**	
3.1	Powerflow Model	3.1	
3.2	Economic Model	3.2	
4	**Needs Assessment**	**4**	
4.1	Economic Needs	4.1	
4.1.1	Target Areas	4.1.2	
4.2	Reliability Needs	4.2	
4.2.1	Base Reliability Assessment	4.2.1	
4.2.2	Market Powerflow Assessment	4.2.2	
4.2.3	Non-Converged Contingencies	4.2.3	
4.2.4	Short-Circuit Assessment	4.2.7	
4.3	Policy Needs	4.3	
4.4	Persistent Operational Needs	4.4	
4.5	Need Overlap	6.1.5	
5	**Solution Development and Evaluation**	**5**	**3**
5.1	Reliability Project Screening	5.3.2	
5.2	Economic Project Screening	5.3.1	
5.3	Short-Circuit Project Screening	4.2.7	
5.4	Public Policy Project Screening	5.3.3	
5.5	Persistent Operational Project Screening	5.3.4	**3**
6	**Portfolio Development**	**6**	
6.1	Portfolio Development Process	6.1	
6.2	Project Selection and Grouping	6.1.1-6.1.4	
6.2.1	Study Estimates	5.2	
6.2.2	Reliability Grouping	6.1.2	
6.2.3	Short-Circuit Grouping	4.2.7	
6.2.4	Economic Grouping	6.1.1	
6.3	Optimization	4.2.7	

Section	Description	ITP Manual Section(s)	ITP Scope Section(s)
6.4	Portfolio Consolidation	6.2	**3**
6.5	Final Consolidated Portfolio	6.2	**3**
6.6	Staging	6.3	
6.6.1	Economic Projects	6.3.1	
6.6.2	Policy Projects	6.3.3	
6.6.3	Reliability Projects	6.3.2	
6.6.4	Short-Circuit Projects	4.2.7	
7	**Project Recommendations**	**6.2**	**3**
8	**Informational Portfolio Analyses**	**7**	**4**
8.1	Benefits	7.1	
8.2	Rate Impacts	6.3	
8.3	Sensitivity Analysis	7.2	**4**
8.4	Voltage Stability Assessment	--	**4**
8.5	Final Reliability Assessment	6.4	

Table 10.2: ITP Manual and 2019 ITP Scope References

11 GLOSSARY

Acronym	Name
ABB	ABB Group licenses the PROMOD enterprise software SPP uses for economic simulations
APC	Adjusted production cost = Production Cost $ + Purchases $ - Sales $
ARR	Auction Revenue Rights
ATC	Available transfer capacity
BA	Balancing Authority
BAU	Business as usual
B/C	Benefit-to-cost ratio
BES	Bulk-Electric System
CC	Combined cycle
CLR	Cost per loading relief
CT	Combustion turbine
CVR	Cost per voltage relief
DPP	Detailed Project Proposal
E&C	Engineering and construction cost
ERCOT	Electric Reliability Council of Texas (ERCOT)
EHV	Extra-high voltage
ESWG	Economic Studies Working Group
FCITC	First contingency incremental transfer capacity
FERC	Federal Energy Regulatory Commission
GI	Generator Interconnection
GIA	Generator Interconnection Agreement
GOF	Generator outlet facilities
GW	Gigawatt
GWh	Gigawatt hour
HV	High voltage
IFTS	Interruption of firm transmission service
IRP	Integrated resource plan

Acronym	Name
IS	Integrated System, which includes the Western Area Power Administration's Upper Great Plains Region (Western-UGP), Basin Electric Power Cooperative, and the Heartland Consumers Power District
ITP	Integrated Transmission Planning
ITP Manual	Integrated Transmission Planning Manual
kV	Kilovolt
LMP	Locational Marginal Price = the market-clearing price for energy at a given Price Node equivalent to the marginal cost of serving demand at the Price Node, while meeting SPP Operating Reserve requirements
MISO	Midcontinent Independent System Operator
MTEP16	2016 MISO Transmission Expansion Plan
MTEP18	2018 MISO Transmission Expansion Plan
MTEP	MISO Transmission Expansion Plan
MDWG	Model Development Working Group
MMWG	Multi-regional Modeling Working Group
MOPC	Markets and Operations Policy Committee
MW	Megawatt
NERC	North American Electric Reliability Corporation
NITSA	Network Integration Transmission Service Agreement
NPV	Net present value
NREL	National Renewable Energy Laboratory
NCLL	Non-consequential load loss
NTC	Notification to Construct
PPA	Power Purchase Agreement
PST	Phase-shifting transformer
RCAR	Regional Cost Allocation Review
RPS	Renewable portfolio standards
SASK	Saskatchewan Power
SPC	Strategic Planning Committee
SPP OATT	SPP Open Access Transmission Tariff
TO	Transmission Owner
TSR	Transmission Service Request

Acronym	Name
TVA	Tennessee Valley Authority
TWG	Transmission Working Group
US EIA	United States Energy Information Administration
VSL	Voltage stability limit

Table 11.1: Glossary

Exhibit BW-4

Request for Proposal

RFP # **SPP-RFP-000003**

RFP ISSUED DATE: September 28, 2020
Updated ISSUE DATE: December 7, 2020

RFP ORIGINATION STUDY:
2019 Integrated Transmission Plan Assessment (“2019 ITP”)

SPP Southwest Power Pool

Table of Contents

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Section 1 - Background

1.1 RFP Solicitation Overview

SPP is issuing this Request for Proposal ("RFP") to solicit proposals from Qualified RFP Participants or QRPs ("Respondent") for the project described below in Section 2 of this RFP. By submitting a response to this RFP, Respondent agrees to be bound by the terms and conditions of this RFP.

This RFP and the overall Transmission Owner Selection Process ("TOSP") are governed by the SPP Open Access Transmission Tariff ("Tariff") and SPP Business Practices. If there is a conflict between this document and SPP's Tariff or Business Practices, the SPP's Tariff and Business Practices shall govern.

1.2 TOSP Deposit

The TOSP deposit and cost calculation are outlined in Section III.2.e. of Attachment Y of the SPP Tariff. The TOSP deposit must be submitted with each RFP proposal submittal, and is required to be paid by electronic funds transfer or by check at the time the RFP Proposal is submitted. SPP will hold each Respondent's TOSP deposit in a segregated interest-bearing account in the name of the Respondent tied to the Respondent's Internal Revenue Service Tax Identification Number. The TOSP deposit required for this RFP proposal is: **$50,000**.

In accordance with Section III.2.e. of Attachment Y of the SPP Tariff, SPP will determine the actual costs to administer the TOSP at the completion of the TOSP. The cost will be allocated to each RFP proposal on a pro-rata share basis; calculated by taking the total TOSP costs for each Competitive Upgrade and dividing by the number of RFP proposals submitted for that Competitive Upgrade. Each Respondent is required to make additional payments or will be eligible to obtain refunds based on the reconciliation of the TOSP deposits collected and actual TOSP costs. Any unused deposit amounts will be refunded with interest earned on such deposits.

1.3 RFP Timetable

The following events are scheduled for this response:

Task	Deadline
RFP Issued Date	9/28/2020
Pre-Response Meeting*	10/21/2020
Notice of Intent to Submit RFP Response**	12/28/2020
Industry Expert Panel Bidder Guidance Document	1/06/2021
Last Date SPP will Accept RFP Questions	3/12/2021
RFP Response/Deposit Deadline by 5 p.m. (Central Time)***	3/29/2021

** The Pre-Response Meeting will be an open meeting to allow QRPs and other interested parties to ask questions and receive feedback prior to submitting an RFP Response. The Q&A will be publicly posted to SPP.org.*
***The Notice of Intent to Submit RFP Response is a non-binding notice that will be used by SPP to assist in estimating the amount of resources required to evaluate the RFP Responses.*
****180 days from September 28, 2020 is March 27, 2021 however this date is a Saturday. Per Attachment Y Section III.2.(c)(xix) in this circumstance the due date shall be the next business day.*

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1.4 Instructions for Submitting an RFP Proposal

The Respondent shall provide the following items in a submitted RFP Proposal:

- A completed RFP Response Form Word and Excel documents, including any supporting documentation itemized in the RFP Response Form as referenced in the Word form "Index of Attachments" section;
- An executed copy of the Acknowledgements in Section 4 of this RFP; and
- The TOSP deposit

All RFP Proposals and any supporting documentation shall be submitted through the SPP Request Management System (RMS) (https://spprms.issuetrak.com/login.asp). The submitter shall use the RMS quick pick, "Transmission Owner Selection Process" subtype 1 "RFP Proposal" when submitting an RFP Proposal.

See SPP Business Practice 7700 for RFP receipt and response information.

1.5 RFP Communication

The Respondent shall submit any inquiries about the RFP process through RMS. RMS responses will be posted publicly in the Wolf Creek-Blackberry RFP Folder on spp.org.

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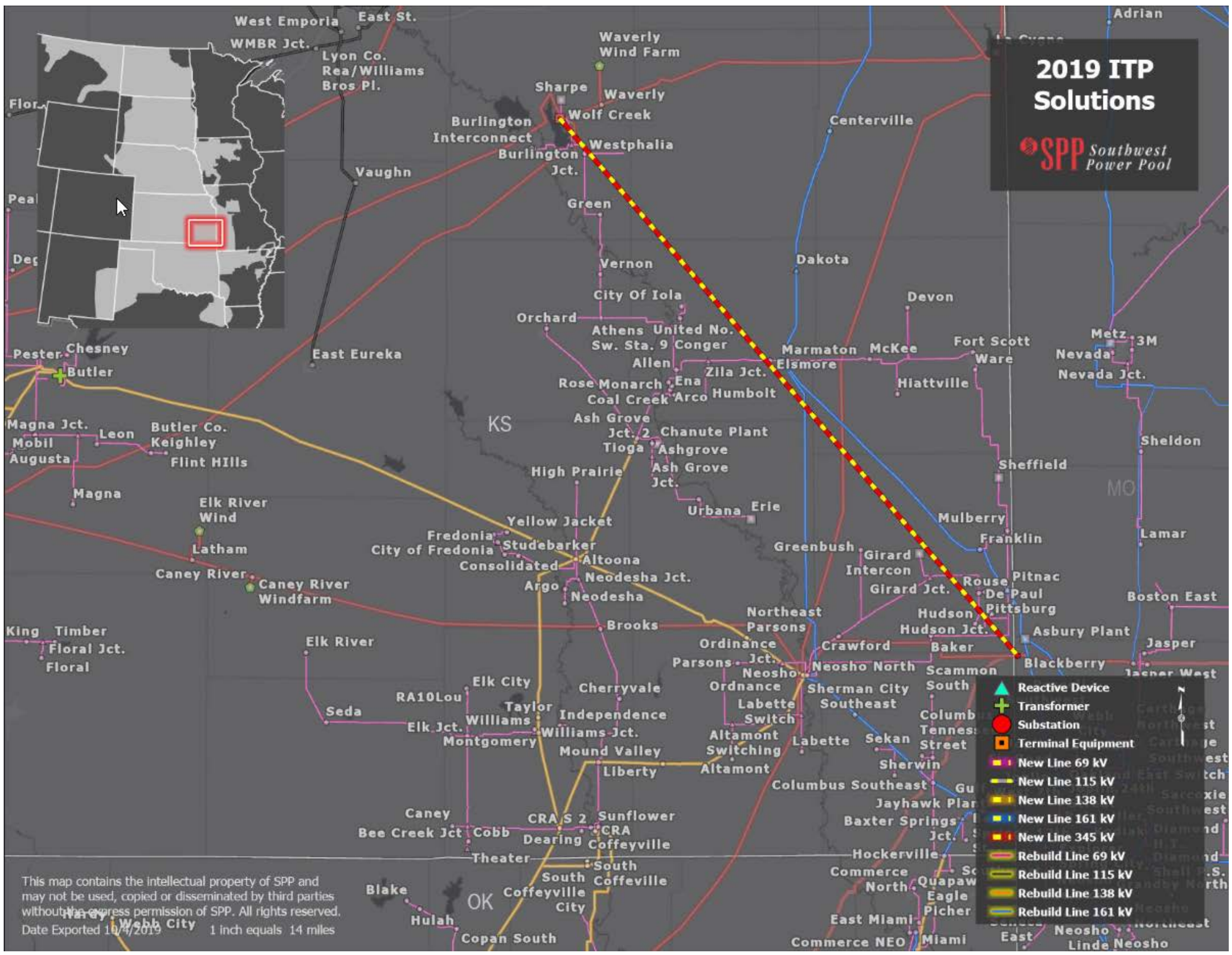
Section 2 – Project Objectives

2.1 Project Overview

On October 29, 2019, the SPP Board approved the new Wolf Creek-Blackberry 345 kV line project (Wolf Creek-Blackberry) for construction as part of the [2019 ITP](#). Wolf Creek-Blackberry meets the requirements of a Competitive Upgrade in Attachment Y of the SPP Tariff.



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2.2 Project Specifications

Project ID: 81547
Need Date for Project: 1/1/2026
Study Cost Estimate for entire Project (+/-30%): $155,524,855
Project Name: Line - Wolf Creek-Blackberry 345 kV
Project Overview: The Competitive Upgrade portion of this RFP requires construction of a new 345 kV transmission line from the Wolf Creek substation to the Blackberry substation to address economic needs.
Date Regulatory Approvals Are Required to Be Completed: 1/1/2023
Expected Financial Expenditure Date: 1/1/2022

The Wolf Creek-Blackberry project includes the following non-competitive portions:

- The Blackberry substation is owned by Associated Electric Cooperative, Inc. (AECI). SPP will coordinate with AECI to install any 345 kV terminal equipment at the existing Blackberry substation necessary to accommodate termination of new 345 kV line. (Project ID: 81547 / Upgrade ID: 112508)
- The Wolf Creek substation is owned by Evergy Kansas Central, Inc. (EKC). SPP will issue an NTC to EKC to install any 345 kV terminal equipment at the existing Wolf Creek substation necessary to accommodate termination of new 345 kV line. (Project ID: 81547 / Upgrade ID: 112509)

The Wolf Creek-Blackberry project includes the following competitive portion:

Competitive Upgrade ID: 122598
Network Upgrade Name: Wolf Creek - Blackberry 345 kV
Network Upgrade Description: Build a new 345kV line from Wolf Creek to Blackberry with a summer emergency rating of 1792 MVA
Network Upgrade Specification: All elements and conductor must have at least a minimum ampacity of 3000 A.
Network Upgrade Justification: Upgrade identified in the 2019 ITP Assessment as an economic project (need date: 1/1/2026).
Study Cost Estimate for Competitive Upgrade: $142,601,178

2.3 Interconnection Information

- Interconnection to the Wolf Creek substation shall be from the north side of the substation. Interconnection will be at a dead end structure[1] located inside the substation.

[1] The transmission line deadend structure will be constructed and owned by the incumbent substation owner. The DTO will own the conductor and the insulators attaching to the dead end structure. The substation owner will attach jumpers to the incoming line at the deadend structure, providing all hardware and conductor necessary to connect from the tap point to the substation buswork. Additionally, the substation owner will provide splice cans on the legs of the substation deadend for termination of the two OPGW fiber cables. DTO will be responsible for attaching OPGW to substation deadend and providing sufficient OPGW for several loops around the splice can. Substation owner will be responsible for terminating OPGW in the splice cans. The selected DTO for the transmission line should reflect any costs/hardware associated with constructing and owning their structures but not include any costs/hardware identified as being owned by the incumbent substation owner to meet this point of interconnection.

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- Interconnection to the Blackberry substation shall be from the north side of the substation. Interconnection will be at a dead end structure[2].
- Fiber optic shall be used for both the primary and redundant communication paths for this project.

2.4 Project Design Standards

The Respondent shall, at a minimum, comply with design specifications as outlined in the Minimum Transmission Design Standards for Competitive Upgrades, Revision 2, dated 12/6/2016 (MTDS), which can be found at http://www.spp.org/publications/Minimum_Design_Standard_Rev_2.pdf. The Respondent shall acknowledge and provide any necessary supporting documentation on how the MTDS requirements have all been met. If the Respondent exceeds the MTDS, then it is the responsibility of the Respondent to detail and support the reason it exceeded the MTDS.

The Respondent shall comply with the SPP Effective Planning Criteria V2.2, as it pertains to this RFP.

2.5 Project Regulatory Context and Authority

Pursuant to Section III of Attachment Y of the SPP Tariff, SPP is issuing this RFP providing QRPs with the opportunity to submit an RFP proposal for Wolf Creek-Blackberry. The SPP Board approved Wolf Creek-Blackberry as part of the 2019 ITP.

2.6 RFP Proposal Cost Estimate

Respondent must include an RFP Response Estimate (RRE) as further described in SPP Business Practice 7060 for Wolf Creek-Blackberry . The RRE will be used by the Industry Expert Panel (IEP) to evaluate the RFP Proposal that will be included in the reports given to the SPP BOARD for RFP selection. The RRE will be used as the established baseline for reporting all cost estimate changes during the Project Tracking process and will be the basis for determining project cost variance. The final project cost is expected to be within a -20% to + 20% variance from the RRE.

[2] The transmission line deadend structure will be constructed and owned by the incumbent substation owner. The DTO will own the conductor and the insulators attaching to the dead end structure. The substation owner will attach jumpers to the incoming line at the deadend structure, providing all hardware and conductor necessary to connect from the tap point to the substation buswork. Additionally, the substation owner will provide splice cans on the legs of the substation deadend for termination of the two OPGW fiber cables. DTO will be responsible for attaching OPGW to substation deadend and providing sufficient OPGW for several loops around the splice can. Substation owner will be responsible for terminating OPGW in the splice cans. The selected DTO for the transmission line should reflect any costs/hardware associated with constructing and owning their structures but not include any costs/hardware identified as being owned by the incumbent substation owner to meet this point of interconnection.

Section 3 – RFP Proposal Process and Requirements

3.1 Respondent Information

The Respondent shall provide information for the authorized person(s) making this proposal and any alternate person with the same authority whom SPP should contact in the event of questions or clarification. If this is a Joint RFP Proposal or Multi-Owner RFP Proposal (or both) as those terms are defined in Section III.2(a) of Attachment Y of the SPP Tariff, Respondent(s) must complete applicable sections within Section A on the RFP Response Form.

- Using the RFP Response Form Word document, complete Section A: RFP RESPONDENT INFORMATION. Include all Respondent(s) and/or Competitive Upgrade Participant(s) information in section A1; if applicable complete information for Joint RFP and/or Multi-Owner RFP information in section A2. If the RFP Proposal is a Joint or Multi-Owner RFP Proposal, sections A2.1 – A2.5 must be completed defining the roles and responsibilities of each respondent in the RFP Proposal.

3.2 RFP Project Summary

The Respondent shall provide overview information related its proposal to Wolf Creek-Blackberry RFP.

- If applicable, complete information in Table B1.2
- All Respondents shall complete information under sections B1.3, B1.4, B1.5, and B1.6

3.3 RFP Supporting Documentation

The Respondent shall provide a complete indexed listing of any and all supporting documentation being submitted with the RFP Response Form referencing the appropriate section identifier under the SUBSECTION ID column.

- Complete INDEX OF ATTACHMENTS section on the RFP Response Form. If no attachment or supporting documentation was provided for a particular subsection of the Response Form, answer "No" in column 2 of the index. If however, a supporting attachment was provided, answer "Yes" and note whether the information is deemed confidential. The file name of the attachment shall be provided in column 4 of the index.

3.4 Engineering Design (Reliability/Quality/General Design)

The Respondent shall provide proposed engineering design and technical information specific to Wolf Creek-Blackberry. Responses should be specific to this upgrade and supported accordingly as to why they were chosen and how they meet all requirements.

- The design wind speed and direction for calculating line rating shall be 2 ft/sec at 90 degrees (normal to conductor).
- The shield design shall be determined based on the anticipated fault currents generating from the terminal substations. The maxium anticipated fault current is 22kA.

- Surge protection shall be applied on all line terminals and power transformers. The expected surge protection energy rating on the line terminals shall be determined through a system study performed by the successful bidder, or an agent of the successeful bidder.

  - Using the RFP Response Form Word and Excel documents complete the following sections listed below:

Section 1: Engineering Design
TRANSMISSION LINE SECTION
- 1A.1 TYPE OF LINE CONSTRUCTION (WOOD, STEEL, DESIGN LOADING, ETC)
- 1A.2 LOSSES (DESIGN EFFICIENCY)[3]
- 1A.3 ESTIMATED LIFE OF CONTRUCTION
- 1A.4 RELIABILITY/QUALITY METRICS
- 1A.5 DESIGN EXPERIENCE
- 1A.6 OTHER COMMENTS

3.5 Project Management (Construction Project Management)

The Respondent shall provide construction project management information specific to its proposal to construct Wolf Creek-Blackberry. Responses should be specific to this upgrade.

- Using the RFP Response Form Word document complete the following sections listed below.

Section 2: Project Management
- 2A.1 ENVIRONMENTAL
- 2A.2 RIGHTS-OF-WAY ACQUISITION
- 2A.3 PROCUREMENT
- 2A.4 PROJECT DEVELOPMENT SCHEDULE (INCLUDING OBTAINING NECESSARY REGULATORY APPROVALS)
- 2A.5 CONSTRUCTION
- 2A.6 COMMISSIONING
- 2A.7 TIMEFRAME TO CONSTRUCT
- 2A.8 EXPERIENCE/TRACK RECORD
- 2A.9 OTHER COMMENTS

[3] Average annual ambient temperature method can be used to calculate losses. Alternatively, losses can be calculated at rated power in MVA without a temperature using the bidder's line resistance parameters R and X:
Current i =(MVA*1000)/(KV*sqrt3)
Real Power Losses P = i^2*R
Reactive Power Losses Q = i^2*X

3.6 Operations (Operations/Maintenance/Safety)

The Respondent shall provide operations information specific to its proposal to operate Wolf Creek-Blackberry. Responses should be specific to this upgrade.

- Using the RFP Response Form Word document complete the following sections listed below.

Section 3: Operations

- 3A.1 CONTROL CENTER OPERATIONS (STAFF,ETC)
- 3A.2 STORM/OUTAGE AND EMERGENCY RESPONSE PLAN
- 3A.3 RELIABILITY METRICS
- 3A.4 RESTORATION EXPERIENCE/PERFORAMNCE
- 3A.5 MAINTENANCE STAFFING/TRAINING
- 3A.6 MAINTENANCE PLANS
- 3A.7 SPECIALIZED MAINTENANCE EQUIPMENT AND SPARE PARTS
- 3A.8 MAINTENANCE PERFORMANCE/EXPERTISE
- 3A.9 NERC COMPLIANCE PROCESS HISTORY
- 3A.10 INTERNAL SAFETY PROGRAM
- 3A.11 CONTRACTOR SAFETY PROGRAM
- 3A.12 SAFETY PERFORMANCE RECORD
- 3A.13 OTHER COMMENTS

3.7 Rate Analysis (Cost to Customer)

The Respondent shall provide detailed rate analysis information for Wolf Creek-Blackberry. Responses should be specific to this upgrade.

- Using the RFP Response Form Word and Excel documents complete the following sections listed below.

Section 4: Rate Analysis

- 4A.1 ESTIMATED TOTAL COST OF THE PROJECT
  - 4A.1.2 PROVIDE THE RRE FOR THIS RFP PROPOSAL
  - 4A.1.3 PROVIDE DTAILS ON WHAT THE BASIS FOR THE COST ESTIMATES ARE FOR TABS 2A AND 2B.
- 4A.2 FINANCIING COST
- 4A.3 FERC INCENTIVES
- 4A.4 REVENUE REQUIREMENTS
- 4A.5 LIFETIME COST OF THE PROJECT TO CUSTOMERS
- 4A.6 RETURN ON EQUITY
- 4A.7 THE QUANTITATIVE COST IMPACT OF MATERIAL ON HAND, ASSETS ON HAND, RIGHTS-OF-WAY OWNERSHIP, CONTROL, OR ACQUISTION
- 4A.8 COST CERTAINTY GUARANTEE
- 4A.9 OTHER COMMENTS

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3.8 Finance (Financial Viability and Creditworthiness)

The Respondent shall provide finance information specific to Wolf Creek-Blackberry. Responses should be specific to this upgrade.

- Using the RFP Response Form Word and Excel documents complete the following sections listed below.

Section 5: Finance

- 5A.1 EVIDENCE OF ABILITY TO FINANCE
- 5A.2 MATERIAL CONDITIONS
- 5A.3 FINANCIAL/BUSINESS PLAN
- 5A.4 PRO FORMA FINANCIAL STATEMENTS
- 5A.5 EXPECTED FINANCIAL LEVERAGE
- 5A.6 DEBT COVENANTS
- 5A.7 PROJECTED LIQUIDITY
- 5A.8 DIVIDEND POLICY
- 5A.9 CASH FLOW ANALYSIS
- 5A.10 DEMONSTRATION OF FINANCIAL STRENGTH
- 5A.11 OTHER COMMENTS

3.9 Conditions of Proposal

In submitting a response to this RFP, the Respondent acknowledges and accepts the conditions detailed in Section 4 (Acknowledgements). To signify such acknowledgement, an authorized representative of Respondent must initial each sub-paragraph and sign at the bottom. If Respondent fails to include such acknowledgments or fails to accept any condition set forth herein, the RFP Proposal will be deemed withdrawn and will be disqualified from consideration.

If the RFP Proposal is a Multi-Owner RFP Proposal or Joint RFP Proposal, an authorized representative from each participating company must acknowledge and accept the conditions detailed in Section 4. If the RFP Proposal does not include such acknowledgements or acceptance of any of the conditions set forth herein by each participating company, the RFP Proposal will be deemed withdrawn and will be disqualified from consideration.

3.10 Confidential Information Identification

The Respondent must identify any information in the RFP Proposal that the Respondent considers to be confidential.

3.11 Information Exchange Requirements

Identification of data required to be provided to the Transmission Provider is in accordance with NERC reliability standards and CEII requirements.

3.12 Confidentiality

In accordance with Attachment Y, Section III.2.d.iii of the SPP Tariff, SPP will not disclose the information contained in any RFP proposal, except to the IEP, until the issuance of the IEP reports in accordance with Attachment Y, Section III.2.d.vi.2 of the SPP Tariff. Any information identified by the Respondent as confidential in the RFP will be redacted from the public version of the IEP report.

3.13 Disclaimer

This RFP is not an offer to enter into a contract, but is merely a request for the Respondent to submit information. Expenses incurred in responding to this request are solely the responsibility of the Respondent. SPP's issuance of this RFP does not constitute any commitment on SPP's part to move forward with Wolf Creek-Blackberry, and SPP may reevaluate Wolf Creek-Blackberry in accordance with the SPP Tariff and Business Practices and withdraw this RFP at any time.

3.14 RFP Evaluation

Pursuant to Attachment Y, Section III of the SPP Tariff, an IEP will evaluate the written proposal. During this time, the IEP may initiate discussions with SPP or the Respondent for the purpose of clarifying aspects of the proposal. However, the proposal may be evaluated without such discussions. The Respondent shall not initiate such discussions with the IEP.

The RFP proposals will be evaluated in accordance with the process in Attachment Y, Section III.2.f of the SPP Tariff.

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Section 4 - Acknowledgments

In submitting a response to this RFP, the Respondent (and, in the case of a Multi-Owner RFP Proposal or Joint RFP Proposal, an authorized representative from each participating company) acknowledges and accepts the following conditions, and makes the following representations. Please initial each sub-paragraph in each box below in your response.

A-1 RFP Proposal – RFP Respondent is providing the completed RFP Response Form, an executed copy of this Section 4 Acknowledgements, a TOSP deposit, as well as any supporting documentation itemized in the RFP Response Form on Tab C.

A-2 No Cure Period – No additions or other changes to the original Proposal will be allowed after RFP Response Window is closed.

A-3 TOSP Deposit – The RFP Respondent will make additional payments or obtain refunds based on the final reconciliation of the TOSP costs for this RFP.

A-4 SPP Membership Agreement – (1) Each RFP Respondent agrees to execute the SPP Membership Agreement as a Transmission Owner if the RFP Proposal is selected by the Transmission Provider, if it has not already done so; and (2) Each Competitive Upgrade Participant in a Multi-Owner RFP Proposal shall agree in writing to execute the SPP Membership Agreement as a Transmission Owner at such time that the entity is first eligible to execute the Membership Agreement as a Transmission Owner, if it has not already done so.

A-5 RFP Withdrawal – SPP may withdraw this RFP at any time.

A-6 SPP Tariff and Business Practices – This RFP and the overall TOSP are governed by the SPP Tariff and Business Practices. If there is a conflict between this document and the SPP Tariff or Business Practices, the SPP Tariff and Business Practices shall govern.

A-7 Joint RFP Proposal – (1) Each RFP Respondent shall be jointly and severely liable for all aspects of finance and construction of the Competitive Upgrade, such that if the Joint RFP Proposal is selected by the Transmission Provider, the other RFP Respondent(s) shall be liable for the defaulting RFP Respondent's(s') obligations in the event that one or more RFP Respondent(s) defaults on its obligations; and (2) In the event that each RFP Respondent(s) does not agree to be jointly and severely liable, as set forth in Section III.2(c)(xiv)(a) of Attachment Y of the SPP Tariff, if the Joint RFP Proposal is selected by the Transmission Provider, the Transmission Provider shall reevaluate the entire Competitive Upgrade pursuant to Section V(4) of Attachment Y of the SPP Tariff if one or more RFP Respondent(s) default on its obligations with respect to the Competitive Upgrade.

A-8 Multi-Owner RFP Proposal – The RFP Respondent acknowledges and agrees that notwithstanding any defaults of any Competitive Upgrade Participant on its obligations under any participation agreement(s), each RFP Respondent, as identified on the RFP Response Form as responsible for any Competitive Upgrade Participant default, is responsible for all aspects of the Competitive Upgrade.

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A-9 Minimum Transmission Design Standards for Competitive Upgrades – The RFP Respondent acknowledges all MTDS have been met, as referenced in Section 2.3 above. If the RFP Respondent exceeds the MTDS, then it is the responsibility of the RFP Respondent to detail and support the reason it exceeded the MTDS. ☐

IN WITNESS WHEREOF, the parties hereto have caused this RFP Proposal to be executed by their respective authorized officials.

RFP Respondent:*

Company Name: ____

By: ______________________ ______________________ ______________________
Name Title Date

Additional Authorized Representatives, if needed:*

Company Name: ____
☐ RFP Respondent ☐ Competitive Upgrade Participant

By: ______________________ ______________________ ______________________
Name Title Date

Company Name: ____
☐ RFP Respondent ☐ Competitive Upgrade Participant

By: ______________________ ______________________ ______________________
Name Title Date

Company Name: ____
☐ RFP Respondent ☐ Competitive Upgrade Participant

By: ______________________ ______________________ ______________________
Name Title Date

* For a single RFP Respondent, only one signature is required. For a Joint RFP, each company submitting the Joint RFP is expected to complete a signature block and indicate “RFP Respondent” under the Company line. For a Multi-Owner RFP, each company submitting the Multi-Owner RFP are expected to complete a signature block and indicate whether they are a “RFP Respondent” or “Competitive Upgrade Participant” under the Company line.

Exhibit BW-5

SPP Southwest Power Pool

HELPING OUR MEMBERS WORK TOGETHER TO KEEP THE LIGHTS ON... TODAY AND IN THE FUTURE

October 11, 2021

Dear SPP Members, Qualified RFP Participants, and Stakeholders:

The Transmission Owner Selection Process ("TOSP") is a part of SPP's Tariff as required by FERC Order No. 1000. As we all know, the competitive nature of the TOSP presents new challenges to SPP's open, transparent and collaborative stakeholder process. One challenge in particular is the fact that our FERC-approved process requires that the Board of Directors ("BOD") review and select the "winning" Request for Proposal ("RFP") proposal via a "blind" competitive process. In other words, the BOD is unaware what entities have submitted RFP proposals until after a RFP proposal has been selected by the BOD following a recommendation report from an Industry Expert Panel ("IEP").

Due to the requirement that the BOD be "blind" as to which parties have submitted RFP proposals, we have decided to implement the following requirement and process for the October 26, 2021 meeting.

Ex Parte Communications – No person or entity shall have any communications, in any form, fashion or medium, with the members of the BOD about the substance of any RFP proposals under consideration or the IEP recommendations and report. Similarly, members of the IEP have been instructed to have no contact with any person or entity about their work on and the results contained in the IEP's recommendations and report, except with certain SPP staff, other IEP members, IEP consultants or information related to any request for information about submitted RFP proposals per SPP's Tariff.

October 12, 2021 – Per Attachment Y of SPP's Tariff, two reports based on the IEP recommendation will be completed – a public report and a non-public report. The public report will redact the identity of submitters, as well as confidential information. This report will be posted on SPP's website. The non-public report will be provided to the BOD. This report will redact only the identity of submitters.

October 26, 2021 – A three-phase process will be used during the BOD web-based meeting in which the BOD selects the Designated Transmission Owner ("DTO") and an alternate RFP proposal ("Alternate DTO").

During Phase 1 and 2 of this process, the IEP will participate via WebEx and present their recommendations to the BOD.[1] During Phase 1, only procedural questions will be permitted and during Phase 2 substantive questions are only permitted by members of the BOD. *The purpose of these prohibitions are to ensure that no questions for the IEP could be used -- intentionally or unintentionally -- to disclose the identity of the entities that have submitted RFP proposals.*

Phase 1: The IEP chairman will present the procedural steps and processes used by the IEP during the review of each RFP proposal. After the IEP chairman presents the procedural aspects, questions submitted by SPP stakeholders via email. Questions should be limited to questions to the IEP about the processes and procedures used by the IEP. Questions, should be emailed to Ben Bright, SPP's Manager of Regulatory Processes, at bbright@spp.org. The BOD members can ask questions during the meeting. *Only procedural questions will be permitted. No substantive questions about the IEP's recommendations or report will be allowed in Phase 1.*

Phase 2: The IEP will present its recommendations and report to the BOD. After the IEP presents its recommendations and report, only BOD members will be permitted to question the IEP about its recommendations and report. *Only the BOD will be permitted to pose substantive questions about the IEP's recommendations or report. Any SPP stakeholder that wishes to request that the IEP address any substantive topics during the IEP's presentation during Phase 2 may submit requested topics to the IEP panel via an email.* ***The IEP, in its sole discretion, will have the final decision on addressing these requests.*** *These emails must be submitted to Ben Bright at bbright@spp.org by October 19, 2021.*

Phase 3: The BOD will discuss the RFP proposals and select the entity that will become the DTO and the Alternate DTO, respectively. Only the BOD will be permitted to debate and/or discuss the competing RFP proposals and recommendations and report from the IEP. *No SPP stakeholder will be allowed to participate in the debate or discussion. As with the standard SPP process, the SPP Members Committee will be polled before the BOD conducts any vote.*

If you have any questions about the above requirements or procedures, please contact Paul Suskie, SPP's General Counsel, at psuskie@spp.org or by phone at 501-831-1622.

Sincerely,

Larry Altenbaumer
Chairman SPP Board of Directors

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[1] The members of the IEP designated by SPP's Oversight Committee will not be announced until the BOD meeting on October 26, 2021.

INDUSTRY EXPERT PANEL TRANSMISSION PROVIDER PUBLIC REPORT

FINAL

RFP-000003
Wolf Creek – Blackberry 345 kV
October 12, 2021

Table of Contents

Acronyms and Definitions

These terms are used in this report and are taken from the SPP Tariff Attachment Y or have been defined by the IEP for use in this report.

ATRR: Annual Transmission Revenue Requirement0

Applicant: An entity that has submitted an application to the Transmission Provider to be a Qualified RFP Participant (QRP).

Competitive Upgrades (CU): Those upgrades defined in Section I.1 of this Attachment Y or an upgrade for which the Transmission Provider must select a replacement Transmission Owner pursuant to Section IV.3 of this Attachment Y.

Criterion: An element in the SPP Tariff, Attachment Y that the IEP is directed to consider in its evaluation of proposals. As part of its evaluation, the IEP members may have further divided a criterion into sub-criteria, and further divided a sub-criterion into factors.

DPP: Detailed Project Proposal

DTO: Designated Transmission Owner

Guaranty: This term shall have the meaning given in Attachment X of this Tariff.

Guarantor: This term shall have the meaning given in Attachment X of this Tariff.

Industry Expert Panel: The panel of industry experts designated by the SPP Oversight Committee to review and evaluate proposals submitted in response to any Request for Proposals in the Transmission Owner Selection Process.

Project: The Wolf Creek-Blackberry 345 kV Transmission Line Project, the Wolf Creek-Blackberry Project.

Present Value of the Revenue Requirement (PVRR): The estimated ongoing cost of operating the project over a 40 year period as calculated in the RFP Response Form Excel Workbook, Tab 3-PVRR

RFP Response Estimate (RRE) Cost Summary: The RRE is the cost to construct the project including materials, labor, equipment, and other non-material costs, as calculated in the RFP Response Form Excel Workbook, Tab 2B.

Request for Information (RFI): A request to one or more Respondents for information related to its proposal.

Request for Proposals (RFP): For purposes of this Attachment Y, a request issued by the Transmission Provider for proposals from QRPs to construct, own, operate, and maintain a Competitive Upgrade.

RFP Proposal or Proposal: A proposal submitted by one or more QRPs in response to a Request for Proposals issued by the Transmission Provider for a Competitive Upgrade.

RFP Respondent: Each QRP involved in the submission of an RFP Proposal that proposes to be the DTO for all or part of a Competitive Upgrade.

Qualified RFP Participant (QRP): An entity that has been determined by the SPP to meet the requirements in Attachment Y to submit a proposal.

ROW: Right of way.

Scoring category: One of the five major categories identified in the SPP Tariff, Attachment Y for evaluation of proposals, which include Engineering Design, Project Management, Operations, Rate Analysis, and Finance.

SPP Tariff, Attachment Y or Attachment Y: SPP's Open Access Transmission Tariff, Sixth Revised Volume No. 1 that sets out the steps for the Owner Designation Process.

Transmission Owner Selection Process (TOSP): The process of determining the Designated Transmission Owner for a Competitive Upgrade pursuant to Section III.2 of this Attachment Y.

Industry Expert Panel Internal Report Executive Summary

Executive Summary

In October 2019, the Board finalized approval of the 2019 Integrated Transmission Planning (ITP) recommendations that included two Competitive Upgrades (CU). One, the Wolf Creek – Blackberry 345 kV Transmission Line Project (Project), which is the subject of this report, and the Sooner – Wekiwa 345 kV Transmission Line Project which was awarded in October 2020. SPP issued a Request for Proposals (RFP) as required by the SPP Transmission Owner Selection Process (TOSP) to qualified entities soliciting proposals to construct, own, and operate the Wolf Creek-Blackberry Project pursuant to Attachment Y of the SPP Tariff.[1]

Once the RFP was approved for issuance, the Oversight Committee approved the selection of five panel members, with a lead and second in each of the five scoring categories described in Attachment Y of the SPP Tariff, and also designated one expert to act as a chairman for the panel.

The newly formed IEP for the Project held multiple conference calls in November and December 2020 in which the group adopted a set of work practices, provided input to SPP staff on the pending IEP Direction to Respondents document, and defined a successful project as one that would be built within the target in-service date, within budget, and would operate and be maintained in accordance with the requirements set out by SPP.

The IEP also discussed the scoring methodology within each scoring category and began to document those methodologies for ultimate inclusion in the IEP Recommendation Report and IEP Direction to Respondents document. The IEP adopted a scoring philosophy that would be used to allocate points to the specific criterion/sub-criterion in each scoring category based upon information provided in the proposals, using this rubric:

- Unacceptable (0%): Proposals that provided information not relevant to the RFP requirements or did not meet the minimum requirements for a particular criterion/sub-criterion were rated "Unacceptable" and were allocated no points for that criterion/sub-criterion.

- Meets Minimum Expectation (50%): Proposals that provided a response that was rated as meeting only the minimum expectations for addressing a particular criterion/sub-criterion were assigned 50% of the available points for that criterion/sub-criterion.

- Good (80%): Proposals that provided an acceptable level of supporting information for a particular criterion/sub-criterion were rated "Good" and allocated up to 80% of the available points for that criterion/sub-criterion.

[1] www.spp.org

- Better (90%): Proposals that provided a better level of supporting documentation for a particular criterion/sub-criterion were rated "Better" and allocated up to 90% of the available points for that criterion/sub-criterion.

- Best (100%): Proposals with the best supporting documentation for a particular criterion/sub-criterion were rated "Best" and allocated up to 100% of the available points for that criterion/sub-criterion.

Scoring in the Rate Analysis category was driven by the lowest RRE and PVRR proposal numbers, and maintains the scoring methodology used in the other categories. All Proposals received greater than the Minimum Expectation Standard of 50% of available points for each criterion/sub-criterion in the Rate Analysis category. One Proposal did receive the Best Scoring of 100% of available points for all scoring criteria/sub-criteria. The rest of the Proposals received a score above the Minimum Expectation Standard and just below the Good Standard of 80% of available points for the RRE and PVRR criteria. None of these Proposals scored in the Better Standard of 90% of available points, reflecting the large dollar difference in their RRE and PVRR values from those of the lowest cost Proposal.

The proposals were made available to the IEP on April 12, 2021. The group designated a letter identifier for each proposal to avoid focus on any Respondent's identity, as shown in Table 1. At all times the IEP sought to conduct its work in a non-discriminatory manner and to operate within the structure set by Attachment Y.

Table 1
Letter Designation for Each Proposal

Letter Designation	Respondent
Proposal A	[redacted]
Proposal B	
Proposal C	
Proposal D	
Proposal E	
Proposal F	
Proposal G	

During the first several weeks of the evaluation period, each IEP member reviewed each of the proposals, examined the information presented that addressed the criteria and sub-criteria within their primary and secondary categories, and determined point allocations consistent with the scoring methodologies developed prior to the beginning of the evaluation period. If the IEP needed additional information from Respondent(s), the IEP instructed SPP staff to send a Request for Information (RFI) to Respondent(s) requesting clarifying information to support the IEP's evaluations. During the entire evaluation period the IEP met weekly by video conference to discuss its evaluations and common issues.

On June 2-3, 2021 the full IEP met via video conference and the lead for each scoring team presented their point allocations for each criterion and sub-criterion in their respective categories for review and discussion by the full IEP. As part of this meeting, the IEP examined whether the allocation of points for any criterion or sub-criterion that overlapped across scoring categories resulted in a double counting or inadequate allocation of points. In addition, the IEP addressed whether the point allocation spread for any criterion/sub-criterion was consistent across scoring categories and did not result in an inappropriate weighting of the total point allocation.

Following these discussions, SPP staff presented a summary tabulation of the point allocations for each scoring category. The results showed that the overall scoring was tightly clustered among the top proposals, as shown in Table 2.

Table 2
Total IEP Point Allocation by Scoring Category and RFP Respondent

Scoring Results Matrix SPP-RFP-000003 Wolf Creek-Blackberry 345kV						
RFP Proposal	Engineering Design (200pts)	Project Management (200pts)	Operations (250pts)	Rate Analysis (225pts)	Finance (125pts)	Total Score
C	184.00	169.00	243.25	225.00	113.13	**934.38**
B	189.00	182.00	239.00	190.17	113.75	**913.92**
A	186.00	182.00	239.00	192.75	113.75	**913.50**
G	178.00	187.00	245.00	180.77	118.75	**909.52**
F	182.00	188.00	196.25	188.32	118.75	**873.32**
E	185.00	179.00	214.38	177.49	93.13	**848.99**
D	179.00	179.00	214.38	180.33	93.13	**845.83**
Average Score	**183.29**	**180.86**	**227.32**	**190.69**	**109.20**	**891.35**

The point allocation for each scoring category including Incentive Points, as described in Section 4 of this Report, is shown in Table 3.

Table 3
Total IEP Point Allocation by Scoring Category and RFP Respondent Including Incentive Points[2]

Scoring Results Matrix SPP-RFP-000003 Wolf Creek-Blackberry 345kV

RFP Proposal	RRE	PVRR	Engineering Design (200pts)	Project Management (200pts)	Operations (250pts)	Rate Analysis (225pts)	Finance (125pts)	Total Score	Qualified for Incentive Pts?	Incentive Pts	Grand Total Score
C	$ 85,168,938	$ 63,235,728	184.00	169.00	243.25	225.00	113.13	934.38	Yes	100.00	1034.38
B	$ 121,105,590	$ 93,655,553	189.00	182.00	239.00	190.17	113.75	913.92	Yes	100.00	1013.92
A	$ 116,544,151	$ 90,494,897	186.00	182.00	239.00	192.75	113.75	913.50	Yes	100.00	1013.50
G	$ 144,924,580	$ 112,766,772	178.00	187.00	245.00	180.77	118.75	909.52	Yes	100.00	1009.52
F	$ 126,505,598	$ 101,289,581	182.00	188.00	196.25	188.32	118.75	873.32	Yes	100.00	973.32
E	$ 151,156,536	$ 116,566,959	185.00	179.00	214.38	177.49	93.13	848.99	Yes	100.00	948.99
D	$ 143,802,827	$ 110,971,071	179.00	179.00	214.38	180.33	93.13	845.83	Yes	100.00	945.83
Average Score	$ 127,029,746	$ 98,425,794	183.29	180.86	227.32	190.69	109.20	891.35	N/A	N/A	991.35

The IEP unanimously recommends Proposal C as the Recommended RFP Proposal. Proposal C received the highest overall point allocation for its proposal to construct, operate and maintain the Wolf Creek-Blackberry 345 kV Transmission Line. Proposal C also received the highest point allocation in the scoring of Rate Analysis, which represents the lowest cost proposal to SPP customers. The strength of Proposal C went beyond being the lowest cost. The IEP recommendation found Proposal C to merit high scores in the vital areas of Engineering Design (including the highest rated conductor of all proposals), Operations and Finance. The high point scores in these areas reflect a balance across scoring criteria that determine the value to SPP customers, not just the cost. The IEP believes Proposal C demonstrated that it offers capabilities and processes that can deliver a successful project, that the proposed designs are robust, and that the resulting costs are competitive.

The IEP unanimously recommends Proposal B as the Recommended Alternate RFP Proposal. Proposal B received the second highest point allocation as shown in Table 2. In addition, Proposal B scored with the highest points on Engineering Design and third in Project Management, Operations, Rate Analysis, and Finance. The Respondent submitting Proposal B is viewed as having the capability and experience to construct, operate and maintain the Project successfully.

[2] Table 3 includes the RRE and PVRR figures for each Proposal

Industry Expert Panel Evaluation Process and Results

Section 1: Industry Expert Panel History

In October 2019, the Board finalized approval of the 2019 Integrated Transmission Planning recommendations. These recommendations included two projects that were determined to be CUs, as described in the SPP Tariff. Each CU is subject to a separate TOSP. This report is to address the Wolf Creek - Blackberry 345 kV project. Under the SPP TOSP, SPP issued an RFP to qualified entities to provide them an opportunity to submit a proposal to construct, own, and operate the CU facility pursuant to the SPP Tariff.

On November 20-21, 2019, the members of the expert pool and SPP Board member Josh Martin attended a two-day training exercise at the SPP headquarters in Little Rock. The experts were provided an overview of SPP and information related to its ITP process, FERC Order 1000, the SPP Order 1000 Process, and SPP Tariff provisions related to Order 1000, as well as the role and expectations of the expert panel.

In April 2020, the SPP Oversight Committee recommended a pool of experts to the Board that would be available for the creation of an industry expert panel should there be CU projects approved for construction. The Board approved the Oversight Committee recommendation to include these experts in the pool for 2020.

On September 28, 2020, SPP published an RFP for the Wolf Creek - Blackberry 345 kV Transmission Project. The RFP terms were largely dictated by Attachment Y of the SPP Tariff. All interested qualified entities were required to submit proposals on or before March 29, 2021. A standard RFP Response template was provided to each qualified entity. In addition to the required response format, each entity was instructed to meet additional guidelines (such as minimum design standards, SPP Operating Criteria, and incumbent interconnection requirements) in their responses. Each of these additional guidelines was noted in the RFP and included detailed documentation of the requirements.

Once the RFP was approved for issuance, SPP proceeded to identify and gain Oversight Committee approval for 5 members of the expert pool to serve as the Industry Expert Panel (IEP) for the Wolf Creek - Blackberry Project, with a lead and second in each of the five scoring categories as shown in Table 4 below.

Table 4
SPP Industry Expert Panel for Wolf Creek - Blackberry Project

Area of Expertise/Scoring Category	Primary Expert	Secondary Expert
Engineering Design	[redacted]	
Project Management		
Operations		
Rate Analysis		
Finance		

On November 5, 2020 the IEP held its initial meeting by conference call. The group covered general organizational issues, RFI philosophy, and set an evaluation schedule. The group also discussed the need to set up a scoring methodology for each category based on the criteria/sub-criteria outlined in the Tariff and any other items each expert felt could be beneficial to their respective scoring category. Finally, the group discussed its initial task to provide input to the IEP Direction to Respondents document by the mid-point of the RFP response window.

In subsequent calls in November and December 2020, the group met via conference call and adopted a set of work practices that included:

- When emails are used for communications with other IEP members, the consultant retained to support the IEP's activities, or the SPP staff, the sender will copy Aaron Shipley and the IEP Chair on each email.
- Aaron Shipley will maintain a master archive of all email communications involving the IEP's activities.
- Before sending an email, each IEP member will review the draft email for clarity of content understanding that the email may be made public at some point.
- IEP members will not initiate contact directly with any RFP Respondent.
- If a RFP Respondent initiates contact with an IEP member, that member will terminate the contact immediately and notify the IEP Chair, Aaron Shipley, and Ben Bright who will assess whether any follow-up action is appropriate.
- An IEP member may request that an RFI be sent to RFP Respondents utilizing the SPP staff to transmit the RFI and receive and distribute responses to the IEP members as appropriate.
- IEP members will retain documents on which they relied in rating the RFP Respondents' proposals until completion of the TOSP, at which time they will delete notes/files used in the TOSP.
- The IEP adopted a scoring methodology that would subdivide each of the five scoring categories into criteria and sub-criteria with assigned points that sum to the point total set for each scoring category in the SPP Tariff, Attachment Y.
- In May 2021, the IEP decided to seek a 30-day extension in its schedule and requested that Aaron Shipley develop the request to the SPP Oversight Committee. The extension request was later approved by the Oversight Committee.

Also in November and December of 2020, the group met via conference call and discussed the appropriate way to measure the ultimate success or failure of the Project, which is categorized as needed for economic purposes. The IEP determined that a successful project would be built within the target in-service date, within budget, and would operate in accordance with the requirements set out by SPP. The IEP also discussed the scoring methodology within each scoring category and began to document those methodologies for ultimate inclusion in the IEP Recommendation Report and IEP Direction to Respondents document.

The IEP also discussed its policy on seeking additional information from RFP Respondents. The IEP determined that each response would be evaluated based on information provided by the Respondent. If required, a clarification would be sought using an RFI to gain a better understanding of the information provided. No additional information would be requested from an individual Respondent so as not to allow one Respondent an unfair advantage to supplement its response. If additional information was needed in the evaluation, a request would be sent to all relevant Respondents. In addition, the IEP determined that its role was to evaluate the information provided for reasonableness and for comparison, but not to serve as an audit function.

The IEP published the IEP Direction to Respondents document on December 21, 2020.

The SPP Staff made the proposals available to the IEP on April 12, 2021, and the IEP designated a letter identifier for each proposal in keeping with the SPP's directive that the IEP should act in an impartial way. These identifiers are listed in Table 5.

Table 5
Letter Designation for Each Proposal

Letter Designation	Respondent
Proposal A	[redacted]
Proposal B	
Proposal C	
Proposal D	
Proposal E	
Proposal F	
Proposal G	

Section 2: IEP Scoring Category Methodologies

The primary and secondary panel expert for each scoring category developed a methodology to allocate a portion of the total points specified in Attachment Y for each scoring category - Engineering Design, Project Management, Operations, Rate Analysis, and Finance – to each of the criteria and sub-criteria that were identified to evaluate the RFP proposals and any additional factors. Each scoring category team presented its methodology to the full IEP for review and comment prior to receiving the proposals and prior to applying it to score the proposals. The IEP discussed areas of potential improvement and agreed on a general approach for scoring, while allowing flexibility within each scoring category for the experts to apply their judgment in designing the methodology and distributing the available points to the criteria and sub-criteria, consistent with the requirements of the SPP Tariff, Attachment Y.

Engineering Design

The SPP Tariff, Attachment Y designates four criteria for the Engineering Design review of the Project:

1(a) Type of construction (wood, steel, design loading, etc.),
1(b) Losses (design efficiency),
1(c) Estimated life of construction; and
1(d) Reliability/quality metrics.

The RFP Response Form Excel Workbook included a "Design Experience" criterion, which was in addition to the Attachment Y requirements. This was added to emphasize that long-term reliability/resilience and performance of the transmission line is dependent on the experience and capabilities of the staff and contractors assigned to designing the Project.

The RFP Response Form Excel Workbook also included an "Other" criterion.

These criteria were further divided into multiple sub-criteria to assist in the evaluation of each proposal, resulting in a total of 44 sub-criteria. The 200 points designated by Attachment Y for Engineering Design were assigned to the summary criteria as shown in Table 6 based on their perceived significance to the success of the Project from an Engineering Design standpoint.

Significant effort was expended to carefully read and review all Engineering documents in all Proposals, including the RFP Response Form, the RFP Response Form Excel Workbook, and multiple Engineering Attachments. Utilizing 18 sub-criteria, a side by side comparison of all Proposals supported the scoring of the criteria/sub-criteria in the Engineering Design category.

The most important criteria and sub-criteria were deemed to be those related to the Structure Configuration, Conductor, and Structure Loadings/Foundations, because they determine whether the transmission line will provide the rated capacity of a minimum of 3000 amps specified by SPP and whether it will provide a safe, resilient, and reliable design for its service life. The conductor selection will govern the line capacity. The structural design must consider the impact of the extreme loading criteria the line will experience during its service life. Reliability of the line is critical to the day-to-day operations of the line through its structural resilience, its design for clearances, and its energized characteristics.

The importance of these three sub-criteria is reflected in the high proportion of points, 36, 24, and 20 points respectively, assigned to these sub-criteria.

The next tier of importance, scoring 20 points each, was for Losses, Life of Construction, Reliability/Quality, and Design Experience for delivering an efficient design/power transfer capability, and Project durability/life, Quality, and experience in designing similar relevant projects.

A third tier of importance, scoring 10 points, was for Shield Wire/dual communication paths. Lastly, four points were allocated for the "Other Comments" sub-criterion.

Table 6
Scoring Methodology Point Designation for Engineering Design

Section 1: Engineering Design (Reliability/Quality/General Design) 200 Pts *Measures the quality of the design, material, technology, and life expectancy of the Competitive Upgrade*	**Sub-criteria**	**Weight**	**Total Pts (200)**
1a) Type of Construction (Wood, Steel, Design Loading, etc.)	1a.1) Design Loading Criteria	10%	20
	1a.2) Conductor Type/Name, Ampacity, Number of sub conductors	12%	24
	1a.3) Shield Wire Type/Name, Number of Shield Wires, Size of Wire	5%	10
	1a.4) Structure Configuration	18%	36
	1a.5) Insulators	6%	12
	1a.6) Dampers	4%	8
	1a.7) Markers	3%	6
	Sub-Total Criteria Pts	58%	116
1b) Losses (Design Efficiency)		10%	20
1c) Estimated Life of Construction		10%	20
1d) Reliability/Quality Metrics		10%	20
1e) Other - Design Experience		10%	20
1f) Other - Comments		2%	4
	Scoring Category Total	**100%**	**200**

Project Management

Attachment Y of the SPP Tariff allocates a maximum of 200 points for the defined criteria in the Project Management scoring category. These criteria are Environmental/Route Selection, Right of Way Acquisition, Procurement and Engineering, Project Development Schedule/Scope, Construction, Commissioning Process, Timeframe to Construct/Milestones, and Experience/Track Record.

The criteria judged to have the greatest impact on the success of the Project were assigned the most points:

Construction - 45 points
Environmental/Route Selection - 30 points
ROW Acquisition - 30 points

The criteria judged to have a medium impact on the success of the Project were assigned the next most points:

Project Development Schedule/Scope - 25 points
Experience/Track Record - 25 points

The criteria judged to have a somewhat lower impact on the success of the Project were assigned a lower number of points:

Timeframe to Construct/Milestones - 20 points
Procurement and Engineering - 15 Points
Commissioning Process - 10 points

The Attachment Y criteria were further divided into more discrete sub-criteria to aid in the evaluation and scoring process. Table 7 lists the final criteria, sub-criteria and the maximum points allocated to each.

Table 7
Scoring Methodology Point Designation for Project Management

Section 2: Project Management (Construction Project management) 200 Pts *Measures an RFP Respondent's expertise in implementing construction projects similar in scope to the Competitive Upgrade*	**Sub-criteria**	**Weight**	**Total Pts (200)**
2a) Environmental	2a.1) Route Selection	10.0%	20
	2a.2) Regulatory	2.5%	5
	2a.3) Support Staff	2.5%	5
	Sub-Total Criteria Pts	15.0%	30
2b) Rights-of-way acquisition	2b.1) Acquisition	10.0%	20
	2b.2) Regulatory	2.5%	5
	2b.3) Support Staff	2.5%	5
	Sub-Total Criteria Pts	15.0%	30
2c)Procument	2c.1) Process	5.0%	10
	2c.2) Support Staff	2.5%	5
	Sub-Total Criteria Pts	7.5%	15
2d) Project Devlopment Schedule/Scope	2d.1) Project Scope/Specifications	7.5%	15
	2d.2) Potential Risks/Mitiagtion Plans	2.5%	5
	2d.3) Reg. approval Process/Mitigation Plans	2.5%	5
	Sub-Total Criteria Pts	12.5%	25
2e) Construction Mangament	2e.1) Process and Plan	12.5%	25
	2e.2) Project Manager and Staff	10.0%	20
	Sub-Total Criteria Pts	22.5%	45
2f) Commissioning/Process		5.0%	10
2g) Timeframe to Construct/Milestones		10.0%	20
2h) Experience/Track Record		12.5%	25
	Scoring Category Total	**100%**	**200**

While all the criteria of Project Management as listed in the RFP and RFP Response Form are important and were scored and evaluated as stated, the criteria that pose the most risk to the successful and timely completion of this Project are the Environmental and ROW Acquisition categories, without which the other aspects of the Project cannot proceed.

The following guidance was provided to Respondents in the IEP Direction to Respondents document with respect to all criteria in the Project Management category and was used by the IEP team in the final evaluation and scoring of proposals.

Environmental

- Respondents should provide a well-defined environmental review and permitting process, and elaborate on their first-hand knowledge of and experience in evaluating all relevant environmental factors, especially those related to this Project as described in the RFP Response Form. This should include discussion of factors reasonably expected to be encountered on the proposed route (e.g., endangered species, cultural areas, etc.).

• Respondents should give particular attention to the development and execution of specific plans for addressing these factors in the affected states and municipalities and securing the necessary regulatory approvals.

Rights of Way (ROW) Acquisition

• Equally important is the Respondent's knowledge of and experience with various transmission line siting approval processes. Respondents should provide instances in the last five years in which they have gained the necessary approvals for ROW acquisition, whether through the exercise of eminent domain or other means.

• Respondents should also provide copies of any documents that demonstrate that it has control of any ROW segments related to this Project. If the Respondent does not have eminent domain rights, it should present its plan and experience for gaining the necessary ROW approvals.

Procurement

• Supply chain management has taken on increased importance with respect to equipment ordered to complete a project, especially if some equipment is planned to be purchased from non-domestic sources. To the extent this is an issue regarding the equipment needed for this Project, Respondents should indicate how they plan to address supply chain management issues.

• The evaluation of each Respondent's proposal will consider the quality of the material providers selected, and the Respondent's prior relationships and evidence of warranties on all material.

• Respondents should provide their QA/QC process for material and equipment procurement, including review of each manufacturer's quality processes and anticipated factory inspections.

Project Development Schedule, Scope, Time to Construct, and Commissioning

• Respondents should provide their detailed processes and plans for managing all aspects of Project development and scheduling, including key milestones for the time to construct and commission the Project.

• Respondents should cite their experience and track record in developing and following a critical path schedule for this Project, including how they have addressed unforeseen obstacles encountered in the past on projects of similar scope and magnitude.

• Respondents should reflect in their Project development schedule a clear understanding of the requirements for access to and performance of work on the Wolf Creek property and within the Wolf Creek substation to connect the new 345 kV line and associated fiber optic communications circuits at the designated dead-end structure.

• Respondents should describe their plan for coordination with the Wolf Creek substation owner, the Wolf Creek Nuclear Operating Company, and the NRC, as necessary, to evaluate any crossing(s) the new 345 kV line will make over or under existing lines out of the Wolf Creek substation. In addition, Respondents should describe any special system studies required to evaluate the impacts of such crossings, including the impact of potential multi-line outages. Respondents should also document any potential restrictions to construction during certain times of the year or during scheduled nuclear plant outages.

Construction

- Respondents should provide specific evidence of significant prior experience in managing the construction of projects similar in scope and magnitude. Respondents should explain how they plan to deploy the necessary support staff, field crews, and material handling resources. Respondents should also describe the safety protocols that will be followed during the construction process. In order to demonstrate its past safety performance, Respondents should provide their Experience Modification Rate (EMR) for previous projects.

- Respondents should provide a Construction Project Organization Chart, and provide resumes of those expected to be in key leadership roles in managing all aspects of construction, including QA/QC process, record keeping, reporting, and their approach to addressing issues that may be encountered.

Operations

Attachment Y of the SPP Tariff provides for a maximum of 250 points for this scoring category. Per Attachment Y, the RFP instructions at Tab 3 describe 12 criteria and associated sub-criteria to assess proposal Respondents' operations, maintenance, safety experience, expertise, and plans as they pertain to the Project facility.

The objectives in allocating the maximum 250 points in this category to the 12 criteria and sub-criteria are: 1) to emphasize that successful operation requires a lifetime commitment to the facility; 2) to recognize that timing is relevant for repairs and storm recovery and there is a difference between what can be done in advance as compared to what would be done in response to external events; and 3) to recognize that the project would operate in a remote location.

Point Allocation

The point allocation system adopted implements the objectives listed above by dividing the 12 criteria into three groups: Operations, Maintenance, and Safety. The sub-criteria for each group, are explained below.

- Operations - control center operations, proposed plan to incorporate this project into a control center for real time monitoring and control, reliability metrics and NERC compliance-process history;
- Maintenance - storm/outage response plan, specialized maintenance equipment and spares, maintenance plans, maintenance staffing/training, maintenance experience and historical performance, and restoration experience and historical performance. Financial strategy for the Project replacement/rebuilds following catastrophic failures will be evaluated as part of the storm/outage response plan; and
- Safety - internal safety programs, contractor safety programs, and safety plans and historical records.

The maximum 250 points for Operations were allocated to these three groups and further subdivided into their sub-criteria. A slightly higher allocation of available points was made to the Maintenance group, followed by Operations and Safety. This point allocation is intended to emphasize that successful operation of the Project:

i) Requires a lifetime commitment to the Project;
ii) Recognizes that timing, and expertise is relevant for repairs and storm recovery, including financial strategy for replacement/rebuilds following catastrophic failures;
iii) Recognizes that there is a difference between what should be done in advance to improve reliability and resiliency as compared to what should be done in response to external events; and
iv) Recognizes that the Project must be operated in a safe manner throughout its life cycle.

Table 8 shows the allocation of 250 points to the 12 criteria under the Operations, Maintenance, and Safety groups.

Table 8
Scoring Methodology Point Designation for Operations

Operations (Operations/Maintenance/Safety) 250 Points *Measures safety and capability of an RFP Respondent to operate, maintain, and restore a transmission facility*	**Sub-criteria**	**Weight**	**Total Pts (200)**
3a) Operations	3a.1) Control Center Operations	10%	25
	3a.2) Reliability Metrics	10%	25
	3a.3) NERC Compliance Process History	10%	25
	Sub-Total Criteria Pts	30%	75
3b) Maintenance	3b.1) Storm/Outage and Emergency Response Plan	10%	25
	3b.2) Specialized Maintenance Equipment and Spare Parts	8%	20
	3b.3) Maintenance Plans	8%	20
	3b.4) Maintenance Staffing/Training	8%	20
	3b.5) Maintenance Performance/Expertise	6%	15
	3b.6) Restoration Experience/Performance	6%	15
	Sub-Total Criteria Pts	46%	115
3c) Safety	3c.1) Internal Safety Program	8%	20
	3c.2) Contractor Safety Program	8%	20
	3c.3) Safety Plan Similar to This Project and Performance Record	8%	20
	Sub-Total Criteria Pts	24%	60
	Scoring Category Total	**100%**	**250**

Rate Analysis

The scoring methodology for the Rate Analysis section (Cost to Customer) is based on Attachment Y. As stated in Attachment Y, the Rate Analysis section measures an RFP Respondent's cost to construct, own, operate, and maintain the Competitive Upgrade over a forty (40) year period.

As stated in the IEP Direction to Respondents document on December 21, 2020, the scoring of the Rate Analysis category used the criteria as listed in Attachment Y grouped within three primary evaluation sub-categories: Total Cost of the Project - RFP Response Estimate (RRE); Present Value Revenue Requirement (PVRR); and Other Attachment Y factors, which could reduce the cost without compromising the quality and risk of the Project.

The IEP evaluator determined that the RRE and PVRR are two distinct rating criteria which are equally important in determining the cost to customers. As a result of this determination, the IEP evaluator assigned 101.25 points to scoring both the RRE criteria and the PVRR criteria. The IEP evaluator made this equal assignment of points to reflect the equal importance of the RRE (cost to construct the Competitive Upgrade) and the PVRR (the cost to own, operate, and maintain) as set forth in Attachment Y.

To reflect further the importance of scoring the RRE and PVRR separately and assigning equal amounts of points to each criterion, the IEP evaluator offers the following logic for this rationale.

RRE

- The RRE is the cost to construct the project including materials, labor, equipment, and other non-material costs, as calculated in the RFP Response Form Excel Workbook, Tab 2 B, while the PVRR is the ongoing cost to operate and maintain the CU over a forty (40) year period.

- Another reason it is important to evaluate and score the RRE is outlined in the Request for Proposal, in Section 2.6 RFP Proposal Cost Estimate.
  "Respondents must include an RFP Response Estimate (RRE) as further described in SPP Business Practice 7060" for Wolf Creek-Blackberry. The RRE was used by the IEP to evaluate the RFP Proposal that will be included in the reports given to the SPP. This panel unanimously agreed additional focus should be put on the RRE and not solely on PVRR. Since the RRE will be used as the established baseline for reporting all cost estimate changes during the Project Tracking process and will be the basis for determining project cost variance.

PVRR

- As stated above the RRE is based on the cost to construct the project including materials, labor, equipment, and other non-material costs. While the PVRR uses some different cost components to calculate its value, it does use as a starting point for its calculations the RRE less AFUDC. Using this adjusted RRE number then the RFP Response Form Excel Workbook calculates the ongoing cost of safely operating and maintaining the project based on using the investment number as a starting point for the PVRR calculation. The costs of operating the project include depreciation, the discount rate, various taxes, operating and maintenance expenses, administration and general expenses, the recovery of the Respondent's weighted average cost of capital, any adjustments to the rate base such as cash working capital, and other operating costs of the project (see Tab 3 – PVRR for a detailed list of the cost items).

In summary, the reason for scoring RRE and PVRR as two distinct criteria is the difference between a Respondent's costs to construct the project versus a Respondent's costs to operate and maintain the project.

As further described in the IEP Direction to Respondents document, points for the first two evaluation sub-categories (RRE and PVRR) were awarded based on the lowest cost numbers (i.e., the lower the cost numbers for RRE and PVRR, the higher the points awarded in each of these sub-categories). The scoring in each of these sub-categories would also be conditioned on the cost proposal meeting the requirements of the other IEP evaluation sections.

The PVRR calculation includes the following Attachment Y criteria:

- RFP Response Estimate (RRE) total
- Financing costs
- FERC incentives
- Revenue Requirements - an estimated present value revenue -requirement (PVRR) for this RFP Proposal by completing Tabs 3-3G of the RFP Response Form Excel Workbook
- Lifetime cost of the Project to customers
- Return on Equity

The third and final evaluation sub-category has a lesser number of points assigned to it than the other two sub-categories. Points will be awarded based on a detailed, quantitative response that demonstrates a reduction in the cost risk of the Project, including the following Attachment Y criteria:

- The quantitative cost impact of material on hand, assets on hand, rights-of-way ownership, control, or acquisition
- Cost certainty guarantee
- Other Comments

The IEP evaluator reviewed all of the proposal documents submitted by Respondents for the Rate Analysis category. The IEP evaluator reviewed the proposal submissions numerous times before scoring the proposals using the evaluation criteria discussed above.

The IEP evaluator verified that the information populated in the RFP Response Form Excel Workbook flowed correctly from worksheet to worksheet. The IEP evaluator also verified that there were no glaring discrepancies between the numerical information in the RFP Response Form Excel Workbook and the proposal narrative. The IEP evaluator not only looked at the calculation of the RRE and PVRR but also the information in the tabs and worksheets that flowed into the calculation of these numbers as part of the ranking and scoring process.

The IEP evaluator identified for evaluation purposes where the numbers in a proposal ranked in comparison to other proposals. For evaluating and scoring purposes, the IEP evaluator did score proposals based on the criteria and sub-criteria outlined in the scoring section with proposals with a lower value RRE and PVRR being awarded more points than proposals with higher value RREs and PVRRs, as long as those proposals satisfactorily met the criteria in the other IEP scoring categories.

RRE Scoring Methodology

The IEP evaluator utilized a two-step process for the RRE scoring methodology. The first step in this process was to determine if a Respondent provided the required RRE information for the Rate Analysis section as outlined in the Wolf Creek -Blackberry RFP. If a Respondent did comply with these RFP standards for the RRE criterion, then it was awarded half of the maximum of 101.25 points (i.e., 50.625). If a Respondent failed to comply with the RFP standards, then it was scored at less than 50.625 points based on the information provided in its proposal.

First Step RRE Points -- 50.625, if the Respondent complied with the RFP standards for the RRE Criterion.

The second step of the RRE scoring process was to assign to each proposal a percentage of the remaining 50.625 points. The proposal with the lowest RRE dollar value will receive100% of the remaining 50.625 points. The proposals with a higher RRE dollar value will be awarded points based on the following two part calculation: the proposal with the lowest RRE dollar value is divided by a proposal with a higher RRE dollar value which equals a percent of the higher RRE dollar value to the lowest RRE dollar value. Then this percentage figure is multiplied by the 50.625 points allocated to this second step of the RRE scoring process.

The actual calculation was as follows:

Second Step RRE Points = [Lowest RRE proposal's dollar value ÷by a Higher RRE proposal's dollar value] *50.625pts.

Once this two-step process was completed, then the points awarded for the first step of the scoring process were added to the points awarded for the second step for a combined total RRE score for each proposal.

Total RRE Points = Points from the 1st step of the scoring process + Points from the 2nd step of the scoring process

Each Respondent's Estimated Total Cost of the Project (RRE) was obtained by the IEP evaluator from each proposal submission. The IEP evaluator listed each Respondent's RRE and compiled several tables and charts to compare the lowest to the highest dollar value of each Respondents' RRE to the other proposal's RREs for evaluation and scoring purposes. The IEP evaluator also developed other tables and charts to illustrate key components of the RRE calculation.

PVRR Scoring Methodology

The IEP evaluator utilized a two-step process for the PVRR scoring methodology similar to what was done for the RRE scoring. The first step was to determine if a Respondent provided the required PVRR information for the Rate Analysis section as outlined in the Wolf Creek -Blackberry RFP. If a Respondent did comply with these PVRR RFP standards, then it was awarded a maximum of 50.625 points out of the 101.25 total points for compliance with these filing standards. If a Respondent failed to comply with the PVRR RFP standards, then it was scored at less than 50.625 points based on the information provided in its proposal.

First Step PVRR Points = 50.625, if the Respondent complied with the RFP standards for the PVRR Criterion

The second step of the PVRR scoring process followed the same approach as was done for the RRE category, using the following formula:

Second Step PVRR Points = [Lowest PVRR proposal's dollar value ÷ by a Higher PVRR proposal's dollar value] *50.625pts.

Once this two-step process was completed, the points awarded for the first step of the scoring process were added to the points awarded for the second step for a combined total PVRR score for each proposal.

Total PVRR Points = Points from the 1st step of the scoring process + Points from the 2nd step

Each Respondent's response to its PVRR ROE was obtained by the IEP evaluator from each proposal submission. In this section of the report the IEP evaluator listed each Respondent's PVRR ROE and compiled tables and charts which compare the lowest to the highest dollar value of each Respondents' PVRR ROE to the other Respondent's PVRR ROE for evaluation and scoring purposes. The IEP evaluator also analyzed and examined the worksheets which flowed into the PVRR ROE such as Investment, O&M expense, A&G expense, AFUDC, and other additions to Rate Base. To illustrate the dollar difference from the lowest to the highest PVRR dollar value, several tables and charts were compiled showing the dollar differences by each proposal for the PVRR ROE lowest value submitted. The IEP evaluator also constructed other tables and charts to illustrate key components of the PVRR calculation.

Cost Certainty Guarantees Scoring Methodology

The IEP evaluator examined all cost certainty guarantee proposals (i.e. cost caps) submitted by Respondents and grouped them into six categories:

- Binding Dollar Cost Cap
- ROE Cap,
- % Equity Cap,
- Schedule Guarantee,
- AFUDC or CWIP in Rate Base;
- Annual Transmission Revenue Requirement (ATRR) Cap

Using these six categories the IEP evaluator reviewed each proposal to determine the effectiveness of the cost caps the Respondent offered including how the terms and conditions for each cost cap provided assurances for cost certainty guarantees. SPP retained an outside consultant to validate the concept of the matrix of the six cost caps developed by the IEP evaluator. Assessment of quality and effectiveness of the cost caps including their terms and conditions were used for scoring. The IEP evaluator developed a table that compares these six cost caps for each Respondent's proposal. This table is contained in the Appendix of this report. The scoring of the cost caps was performed solely by the IEP evaluator.

The scoring methodology point designation for Rate Analysis is shown in Table 9.

Table 9
Scoring Methodology Point Designation for Rate Analysis

Section 4: Rates (Cost to Customer) 225 Pts *Measures an RFP Respondent's and, if applicable, a CU Participant's cost to construct, own, operate, and maintain the Competitive Upgrade over a 40-year period*	**Sub-criteria**	**Weight**	**Total Pts (200)**
4a) Estimated Total Cost of Project (RFP Response Estimate - RRE)		45%	101.25
4b) Present Value Revenue Requirement (PVRR)	4b.1) Financing Costs		
	4b.2) FERC Incentives		
	4b.3) Revenue requirements		
	4b.4) Lifetime Cost of the Project to Customers		
	4b.5 Return on Equity		
	Sub-Total Criteria Pts	45%	101.25
4c) Other Attachment Y Factors	4c.1) The quantitative cost impact of material on hand, assets on hand, rights-of-way ownership, control, or acquisition		
	4c.2) Cost Certainty guarantee		
	4c.3) Other Comments		
	Sub-Total Criteria Pts	10%	22.5
	Scoring Category Total	**100%**	**225**

Finance

The SPP Tariff, Attachment Y provides a maximum of 125 points for scoring the Finance section of RFP responses. To establish the viability and creditworthiness of the proposals, and the analyses requested, Attachment Y lists eight criteria to be used: Evidence of the Respondent's ability to obtain financing; Material conditions; Financial/business plan; Pro forma financial statements; Expected financial leverage; Debt covenants; Projected liquidity; Dividend policy; and Cash flow analysis.

The RFP provided initial guidance regarding the information expected from Respondents, stating "The Respondent shall provide financial information specific to the Wolf Creek-Blackberry Project. Responses should be specific to this upgrade." The descriptions and analyses provided by Respondents to the RFP were evaluated as evidence indicating the plans and preparations of the respective Respondents to meet the demands of financing the Wolf Creek-Blackberry Project. Attention was given to the assumptions made for inputs the Respondent used. The Respondents that support the assumptions for external factors and expectations for other inputs to this section were scored higher than the Respondents that did not support the expectations or assumptions.

The description of the Finance category in Attachment Y emphasizes financial viability and creditworthiness. This evaluation is intended to measure an RFP Respondent's and, if applicable, a CU Participant's ability to obtain financing for the Competitive Upgrade. The weights and scoring of the criteria were selected to reveal differences in the proposals' presentation of their preparations to define a financing strategy, collect meaningful inputs and assumptions to use in financial projections, and broadly show that there are fewer risks to achieving this strategy and achieving the financial, engineering, construction and operational objectives of the proposal.

The Table 10 below displays the weights and maximum possible points for the criteria listed in the RFP and Attachment Y.

Table 10
Scoring Methodology Point Designation for Finance

Section 5: Finance (Financial Viability and Creditworthiness) 125 Points *Measures an RFP Respondents and, if applicable, a CU Participant's ability to obtain financing for the Competitive Upgrade.*	**Weight**	**Total Pts (125Pts)**
A) Evidence of Financing	10%	12.5
B) Material Conditions	5%	6.25
C) Financial/Business Plan	25%	31.25
D) Pro Forma Financial Statements	15%	18.75
E) Expected Financial Leverage	5%	6.25
F) Debt Covenants	5%	6.25
G) Projected Liquidity	15%	18.75
H) Dividend Policy	5%	6.25
I) Cash Flow Analysis	15%	18.75
Scoring Category total:	**100%**	**125**

Section 3: IEP Scoring Category Results

In the initial meetings of the IEP after receiving and reviewing the proposals, the IEP examined and confirmed that the seven Proposals provided qualified and adequate proposals to build the Wolf Creek-Blackberry Project. The seven Proposals were submitted by four Respondent teams. Three of these Respondents each prepared two Proposals. [redacted]

Through weekly video calls, the IEP members described their on-going review and evaluation of each proposal. Discussions emphasized the application of the previously developed scoring methodology to the information provided by each RFP Respondent in its proposal.

Points were allocated to the criterion/sub-criterion for each scoring category based on the information provided in each Proposal including attachments and appendices, using this rubric:

- Unacceptable (0%): Proposals that provided information not relevant to the RFP requirements or did not meet the minimum requirements for a particular criterion/sub-criterion were rated "Unacceptable" and were allocated no points for that criterion/sub-criterion.

- Meets Minimum Expectation (50%): Proposals that provided a response that was rated as meeting only the minimum expectations for addressing a particular criterion/sub-criterion were allocated 50% of the available points for that criterion/sub-criterion.

- Good (80%): Proposals that provided an acceptable level of supporting information for a particular criterion/sub-criterion were rated "Good" and allocated up to 80% of the available points for that criterion/sub-criterion.

- Better (90%): Proposals that provided a better level of supporting documentation for a particular criterion/sub-criterion were rated "Better" and allocated up to 90% of the available points for that criterion/sub-criterion.

- Best (100%): Proposals with the best supporting documentation for a particular criterion/sub-criterion were rated "Best" and allocated up to 100% of the available points for that criterion/sub-criterion.

Scoring in the Rate Analysis category is driven by the lowest RRE and PVRR proposal numbers, and follows the scoring methodology used in the other categories. All Proposals received greater than the Minimum Standard of 50% points for each criterion in the Rate Analysis section. One Proposal did receive the Best Scoring of 100% of points for all scoring criteria. The rest of the Proposals received a score above the Minimum Standard and just below the Good 80% of points for the RRE and PVRR criteria. None of these Proposals scored in the Better Scoring 90% of points, reflecting the large dollar difference in their RRE and PVRR values from those of the lowest cost Proposal.

The IEP noted that the evaluation of proposed conductors was not straight forward in terms of the benefits of the lower losses of those conductors. The various economic and performance advantages of conductors that exceeded the RFP minimum were not easily or uniformly quantified for comparison with the minimum conductor in characteristics in the Engineering Design category. However, the additional cost for that greater capability was readily captured in the Rate Analysis category.

[redacted] This Proposal offered distinct advantages in the Environmental/Route Selection and Right of Way Acquisition categories, which resulted in higher scores in the Project Management Category. [redacted] Concerns about cost subsidies for the Rate Analysis review and questions regarding Operations were also inadequately addressed in Proposal [redacted]. Some of these weaknesses are described further in this report and associated Appendix.

Engineering Design

Point allocations were made to each criterion/sub-criterion for each proposal based on the information submitted in the RFP response documents. The RFP Response Form Excel Workbook contained line items for more information and provided additional details that provided better insight into other sub-criteria that were assigned point values. Some of the comparisons and allocations were quantitative, while others were qualitative assessments based upon how well the response documented the Respondent's ability to deliver the desired engineering design for the Project.

Type of Construction, including Loading Criteria/Foundations, Conductor, and Structure Configuration, knowledge of and compliance with SPP Planning Process, SPP Minimum Transmission Design Standards, applicable code, and regulatory requirements were carefully evaluated and had the greatest importance in scoring because these factors impact the performance, reliability and resilience of the conductor, structure, foundation designs and ultimately the capital costs. Performance over the service life of the assets, attributed to the structural system loading criteria, structure configuration, and materials also had a significant impact on the scoring because these factors address the safety, reliability, resilience, and quality of the transmission line.

An initial task was to examine whether each proposal met engineering design criteria set out in the RFP. The RFP was specific as to several minimum requirements found in the SPP Minimum Transmission Design Standards (MTDS)[3] and to the minimum line rating of 3000 Amps.

In general, the Engineering Design sections of all proposals were complete and of high quality, with only some slight variations. For example, some Respondents went to greater lengths on Geotech investigations compared to others, some included more specific detailed Studies than others, and some used slightly different assumptions for detailed Studies.

All proposals included a two-conductor bundle and two shield wires. Two shield wires allowed for good lightening protection/performance by all the Respondents. The redundant communications RFP requirement was met, either with dual shield wires with fiber optic capability, or in one case, one fiber optic shield wire and a secondary path utilizing a leased communication path.

All proposals were based on a single pole (steel or concrete). Some utilized a braced post insulator, and some a davit arm with either V String or I String suspension insulators. One Respondent utilized self-supporting angle and dead-end structures (no down guys) [redacted]

With respect to Losses, each proposal was reviewed to record its line rating and validate that the parameters used to calculate the rating were as prescribed by SPP. Again, all proposals were compliant with the RFP, with some variation in the conductor selected and Losses calculated. Most proposals include a very detailed Conductor Selection Study.

Live line work capability also was deemed to have a significant impact on Reliability and Structural criteria. While not required by SPP, designs capable of live line work would provide greater flexibility for future maintenance and added reliability associated with clearances.

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[3] "Minimum Transmission Design Standards for Competitive Upgrades Rev2. SPP. December 2016; SPP Planning Criteria Revision 2.1. February 18, 2020.

All proposals included information on the design staff and experience with similar projects. All were highly qualified and had significant experience. [redacted].

In general, the Proposals (Engineering Design category) were complete, comprehensive, and of high quality, with only some slight variations, leading to only slight variations in scoring, from 178 to 189 points.

The allocation of points within Engineering Design for each criterion and sub-criterion by proposal is shown in Table 11.

Table 11
Engineering Design Point Allocation by Criterion and RFP Respondent

Section 1: Engineering Design (Reliability/Quality/General Design) 200 Pts *Measures the quality of the design, material, technology, and life expectancy of the Competitive Upgrade*	**Sub-criteria**	**Weight**	**Total Pts**	**A**	**B**	**C**	**D**	**E**	**F**	**G**
1a) Type of Construction (Wood, Steel, Design Loading, etc.)	1a.1) Design Loading Criteria	10%	20	20	20	18	19	19	19	19
	1a.2) Conductor Type/Name, Ampacity, Number of sub conductors	12%	24	20	22	22	20	24	19	19
	1a.3) Shield Wire Type/Name, Number of Shield Wires, Size of Wire	5%	10	10	10	10	10	10	9	9
	1a.4) Structure Configuration	18%	36	34	34	32	29	29	36	32
	1a.5) Insulators	6%	12	11	11	10	12	12	11	11
	1a.6) Dampers	4%	8	8	8	8	8	8	8	8
	1a.7) Markers	3%	6	6	6	6	6	6	6	6
	Sub-Total Criteria Pts	58%	116	109	111	18	104	108	108	104
1b) Losses (Design Efficiency)		10%	20	17	18	18	17	19	16	16
1c) Estimated Life of Construction		10%	20	19	19	18	18	18	18	18
1d) Reliability/Quality Metrics		10%	20	19	19	20	17	17	18	18
1e) Other - Design Experience		10%	20	19	19	19	20	20	18	18
1f) Other - Comments		2%	4	3	3	3	3	3	4	4
	Scoring Category Total	**100%**	**200**	**186**	**189**	**184**	**179**	**185**	**182**	**178**

Project Management

The evaluation of each Respondent's proposal and assignment of the available 200 points in this scoring category was based on the information provided by the Respondent and the extent to which it demonstrated the Respondent's ability to complete the Project within the scope, proposed budget, and schedule.

After the initial review of the proposals, it was concluded, based upon individual experience and project management capabilities, that all Respondents could construct the Project based on the scope specified in the RFP by the target in-service date, and within the proposed budget. Therefore, all Respondents received an initial score of "*Good*" under all criteria. The task then became determining which proposals would elevate to a score of "*Better*" or "*Best*" for each criterion and sub-criterion. The remainder of the evaluation process assessed each Respondent's ability to articulate its expertise and capabilities in each of the criteria and sub-criteria.

By its nature, the Project Management category and each of its criteria and sub-criteria are more qualitative than quantitative, leaving it to the judgement of the evaluator based on the information provided in the Proposal to assign an appropriate score.

The following three criteria, Environmental, ROW, and Construction, are judged to have the greatest impact on the success of the Project.

Environmental (30)
Route Selection - 20
Regulatory - 5
Support Staff - 5

All Respondents indicated that they have retained or are planning to retain experienced contractors/consultants with first-hand knowledge and experience with the area expected to be traversed by the new line as well as familiarity with the various regulatory/permitting processes and agencies in Kansas and Missouri, which experience will assist in routing and environmental permitting. All proposals provided well-defined plans for addressing all relevant environmental, endangered species, and cultural issues unique to the region, including mitigation plans to address risks associated with the selected route. Finally, all Respondents indicate their plan to assign experienced staff resources to this portion of the Project, leading to a "*Best*" score for the Support Staff sub-criteria for each proposal.

The Regulatory sub-criteria was rated "Good" for all proposals with the exception of Proposal F, which was rated "Best" [redacted]

The Route Selection sub-criteria for Proposal F was also rated "Best" [redacted]

Proposals A/B and Proposal G were both rated "Better" based on their description of their detailed route selection processes and how these processes had been used successfully for other projects.

Proposals C and D/E were judged "Good" but did not have the inherent advantages found in the other proposals. Proposal C indicated Respondent's parent company had a great deal of experience developing transmission [redacted] Of these projects, Proposal C noted 80% were completed on schedule or sooner. In addition, the Respondent for Proposals D/E indicated they had proactively reached out to landowners and the public in advance of being awarded the project.

Right Of Way (30)
Acquisition - 20
Regulatory - 5
Support Staff - 5

All Respondents have extensive Land Acquisition Plans (including timelines) and have engaged experienced contractors to assist in acquiring the necessary easements for the line itself as well as for additional property needed for site access and construction.

All Respondents and their contractors have strong preference for fair market pricing of properties needed for the Project, and plan for several open house events to address landowner issues.

All proposals were rated "Good" or "Best" as it pertains to the Regulatory and Support Staff sub-categories.

All Respondents have experience and plans for obtaining eminent domain if necessary; all plan to use it as a last resort.

Proposal F is again rated "Best" in all aspects of ROW Acquisition, [redacted]

Respondent for Proposal C has already contacted 10% of the landowners for parcels needed, have signed option agreements for 15 parcels, and are in active negotiations for 50 additional parcels.

Proposals A/B, D/E and G are all rated "Better". Respondent for Proposals A/B has extensive experience acquiring ROW [redacted], including >700 miles for EHV transmission, and are using qualified land agents with specific experience in Kansas and Missouri. Respondent for Proposals D/E have a Route Development Agreement with their parent company to leverage resources.

Construction (45)
Process and Plan - 25
Project Manager and Staff - 20

All Respondents identified their detailed Construction Management Processes, including deploying highly qualified and experienced contractors and staff. All plans include detailed safety protocols applicable to all participants in the process.

Proposal G rates "Best" for both Process and Plan and Project Manager and Staff. Highly experienced, well-qualified construction team includes personnel with more than 180 years of combined experience constructing EHV transmission projects.

Proposal G indicates that ROW input will be integrated into construction planning early on; ensuring the full scope of ROW needs (from temporary construction access, crane pad, and pulling station locations to long-term access agreements) are considered.

Local utility partner will provide on-site Transmission Construction Representatives to monitor construction practices and methods, inspect construction installation quality, ensure adherence to safe work practices and programs, and assist the [redacted] in coordinating construction activities with other utilities.

[redacted]

Proposal F is only marginally weaker than Proposal G for the Process and Plan sub-criteria [redacted]

Proposals A/B and D/E are judged "Better" for both Process and Plan and Project Manager and Staff due to their extensive experience constructing projects of similar scope. Proposal C is judged "Good" based on 80% of their previous competitive upgrade projects completed on or ahead of schedule.

The following two Criteria, Project Development Schedule/Scope and Experience/Track Record are judged to have a medium impact on the success of the Project.

Project Development Schedule/Scope (25)
Project Scope/Specifications - 15
Potential Risks/Mitigation Plans - 5
Regulatory Approval Process/Mitigation Plans - 5

All Respondents provided the required schedules and "no later than" dates for regulatory approvals, environmental permits, ROW acquisition, engineering and design, material procurement, construction, commissioning, energization, and final in-service date.

All Respondents identified potential schedule risks and planned mitigation measures, including utilizing schedule float.

Proposal G was judged "Best" in each of the sub-categories. Experience of all involved parties enable Respondent to provide a realistic schedule [redacted] based on significant development work already performed.

Respondent for Proposal F also has the [redacted]

Proposal F Project Team also has experience with planning and installing lines [redacted]; anticipated that Respondent can easily transition from award to siting approval.

Respondent for Proposals A/B was judged "Good" on all aspects of this category. Expended significant effort to develop a thorough understanding of Project specific construction requirements, e.g., clearing, access roads, site grading, foundations and anchors, and wire stringing. Also included 80 potential risks and associated mitigation plans, including final route evaluation, regulatory permitting, permit conditions/requirements, ROW/land acquisition, material procurement, construction, Wolf Creek access, commissioning and energization.

Proposals C and D/E, judged "Better" to "Best" in terms of their detailed approach to identifying risks and mitigation plans.

Respondent for Proposal C offers a guaranteed [redacted]

Respondent for Proposals D/E has substantially negotiated Project Agreements with key partners and contractors. [redacted]

Experience/Track Record (25)
All Respondents have demonstrated experience and strong track records in successfully constructing significant EHV transmission projects in the last five years.

Proposals A/B and D/E are judged "Best" (100%) with regard to Respondents' experience in successfully completing transmission projects of similar scope.

Respondent for Proposals A/B will leverage experience of parent organization delivering projects subject to schedule guarantees; [redacted] Directors of Respondent organization have 20 - 36 years' experience; Contractors have Kansas and Missouri based staff and/or experience.

Construction Contractor has recent experience in Kansas and Missouri [redacted] 290 mi 345 kV in KS, 115 mi 138/69 kV in Kansas and Missouri.

Respondent organization for Proposals D/E formed specifically to develop, own, construct, acquire, operate, lease and otherwise manage parent company's strategic investment in FERC-regulated electric transmission infrastructure across the U.S., [redacted]

Proposal C judged "Better". Will operate under a "support services" model; draw on the entire range of resources of its parent and affiliated companies to ensure successful delivery of the Project. [redacted]

Proposals F and G judged "Better". Respondent employs a Project Lifecycle Management Process, providing a structure to accurately scope and document projects during their life cycles from development to closeout. [redacted]

[redacted]

[redacted]

The following three criteria, Timeframe to Construct/Milestones, Procurement and Engineering, and Commissioning Process, are judged to have a somewhat lower impact on the success of the Project.

Timeframe to Construct/Milestones (20)

All Respondents provided adequate descriptions of their proposed time to construct date in their "Project Development Schedule." Milestone dates and potential risks were also provided.

Proposals A/B, judged as "Best" have substantial float in all phases; [redacted] Will consult with affected parties on benefits of early energization.

If not have all land rights, can start construction where rights have been obtained. No requirement for simultaneous outages of multiple lines.

Project schedule for Proposal C, judged "Better"; has built-in flexibility [redacted]

Proposals F&G judged "Better". Total duration of the Project, from award to in-service [redacted] more than adequate time for preconstruction, all work disciplines, and testing/commissioning activities. Combined overall flexibility of [redacted] on how long it takes SPP from the date of the expected award to issuing the NTC for the Project; [redacted]

Proposals D/E judged "Good".
Potential project risks/mitigations based upon previous experience and information gathered during the RFP response process: ROW Acquisition; Material Quality; Subsurface Conditions; Third Party Outages; Weather.

Procurement (15)
Process - 10
Support Staff - 5

All Respondents:
- Provided comprehensive Procurement and Project Management Plans as called for in the RFP, and plan to use qualified/experienced staff and contractors;
- Described their planned QA/QC program and process with respect to material and equipment procurement, including inspections of materials and equipment at vendors' sites and at construction sites; and
- Indicated their plan to use qualified and experienced material and equipment providers who are expected to provide evidence of warranties on all material and equipment.

Proposals D/E, F & G were judged "Best" in both Process and Support Staff. [redacted] Quality Management Program will ensure all suppliers meet specs prior to start of manufacturing. EPC contractor has already competitively bid all materials and discussed material manufacturing and delivery timelines to prevent risk of delays. Will lock in manufacturing windows with suppliers in advance of contract signing.

Respondent for Proposals F&G has significant collective buying power through affiliated/subsidiary companies; [redacted]. Executed EPC contract with highly capable and experienced contractor; proof of performance with 10 projects; ready to implement without further negotiation.

[redacted] Proposals A/B and C judged "Better".

Respondent for Proposals A/B plans to retain one of the largest EHV transmission construction contractors in the U.S.; used for >700 mi. of 345 kV transmission in the past 10 years and T&D design and engineering firm with 100 years' experience; [redacted].

Respondent will directly purchase all major materials from pre-qualified suppliers based on recent performance, ability to meet schedules and design specs without defects; will use a single supplier for insulator assemblies/hardware to ensure proper fit.

Parent company maintains a stockpile of 345 kV equipment that can be used in event of delivery issues.

Proposal C will use the application process to identify and pre-approve "preferred vendors," and has secured space and priority from vendors' manufacturing queues. Parent company has long-standing development and supply alliances with vendors. Respondent plans to enter into project specific agreements to purchase major equipment.

All material and equipment will be designed and manufactured specifically for this project. Third-party services and materials will be procured through Integrated Supply Chain process; will use all domestic materials and equipment.

Commissioning Process (10)

Respondents for Proposals A/B, C, and D/E have adequately described their commissioning plans, including detailed descriptions of items to be considered, coordination plans with Wolf Creek and Blackberry substation owners, and interconnection agreements; Proposal C judged "Best" and Proposals A/B and D/E judged "Better".

Commissioning Manager for Proposal C has over 19 years of experience; responsible to ensure line and substation assets are tested and commissioned in accordance with interconnection agreements negotiated with each of the substation owners. Designed to occur in the shortest amount of time, no disruptions to electrical service and eliminate the need for future outages.

Construction will require crossing of the Wolf Creek to La Cygne 345 kV Line outside of the Wolf Creek facility, which will require coordination with Evergy, La Cygne Substation and Wolf Creek Generating Station. Switching orders will be prepared consistent with SPP and AECI requirements. Record of successful interconnection processes combined with Respondent's nuclear experience significantly reduces the risk to timely interconnection agreement at Wolf Creek.

Construction Director for Proposals A/B will have the primary responsibility for managing the commissioning activities in coordination with the Project Director. Project Director to develop energization procedure with substation owners and enter into interconnection agreements. Respondent will coordinate outage schedules based on availability of outages at Wolf Creek and Blackberry. Post energization inspection to confirm Project as-built including LIDAR survey. Prior to energization, Respondent and construction contractor will drive the length of the line to verify the phases are correctly aligned and that all construction grounds and safety devices have been removed.

EPC contractor for Proposals D/E will perform detailed checks and acceptance testing of both the transmission and fiber optic system after concluding its detailed QA/QC procedures to verify that the line is in conformance with Power Engineers and Foundation Acceptance standards, and that all grounds have been removed. Testing will include a detailed list of acceptance tests, including: Transmission Line Clearance Verification, Compression Splice Inspection Report, and Fiber Optic testing. Access Road Conditions and ROW Conditions will be completed as work is completed; final inspection conducted to make sure all clean-up is complete for the project.

Proposal F is judged "Good" due primarily to the lack of detailed information how commissioning will be coordinated [redacted]

Proposal G is judged "Good".

Respondent and EPC contractor for Proposals F&G have proposed a construction schedule that allows the line to be available early to coordinate outages, testing, and energization. Substation owners responsible for developing site-specific zones of protection, testing, and commissioning plans for the equipment at their respective existing substations. Respondent anticipates that its construction and installation work can be completed without the need for substation outages because its scope ends at the attachment point of the interconnect poles outside of the energized substations.

Table 12
Project Management Point Allocation by Criterion and RFP Respondent

Section 2: Project Management (Construction Project management) 200 Pts *Measures an RFP Respondent's expertise in implementing construction projects similar in scope to the Competitive Upgrade*	**Sub-criteria**	**Weight**	**Total Pts**	**A**	**B**	**C**	**D**	**E**	**F**	**G**
2a) Environmental	2a.1) Route Selection	10.0%	20	18	18	15	15	15	20	18
	2a.2) Regulatory	2.5%	5	4	4	4	4	4	5	4
	2a.3) Support Staff	2.5%	5	5	5	5	5	5	5	5
	Sub-Total Criteria Pts	15.0%	30	27	27	24	24	24	30	27
2b) Rights-of-way acquisition	2b.1) Acquisition	10.0%	20	17	17	15	17	17	20	17
	2b.2) Regulatory	2.5%	5	5	5	4	5	5	5	5
	2b.3) Support Staff	2.5%	5	5	5	5	5	5	5	5
	Sub-Total Criteria Pts	15.0%	30	27	27	24	27	27	30	27
2c)Procument	2c.1) Process	5.0%	10	9	9	9	10	10	10	10
	2c.2) Support Staff	2.5%	5	5	5	5	5	5	5	5
	Sub-Total Criteria Pts	7.5%	15	14	14	14	15	15	15	15
2d) Project Devlopment Schedule/Scope	2d.1) Project Scope/Specifications	7.5%	15	12	12	13	14	14	14	15
	2d.2) Potential Risks/Mitiagtion Plans	2.5%	5	4	4	5	5	5	4	5
	2d.3) Reg. approval Process/Mitigation Plans	2.5%	5	4	4	4	4	4	5	5
	Sub-Total Criteria Pts	12.5%	25	20	20	22	23	23	23	25
2e) Construction Mangament	2e.1) Process and Plan	12.5%	25	22	22	20	22	22	23	25
	2e.2) Project Manager and Staff	10.0%	20	18	18	15	18	18	20	20
	Sub-Total Criteria Pts	22.5%	45	40	40	35	40	40	43	45
2f) Commissioning/Process		5.0%	10	9	9	10	9	9	7	8
2g) Timeframe to Construct/Milestones		10.0%	20	20	20	18	16	16	18	18
2h) Experience/Track Record		12.5%	25	25	25	22	25	25	22	22
	Scoring Category Total	**100%**	**200**	**182**	**182**	**169**	**179**	**179**	**188**	**187**

Operations

Rating method

To conduct the comparative analysis and score appropriately, each proposal was judged and evaluated based on the information and data provided by the Respondent. The purpose was: i) To ensure each Proposal provided relevant and sufficient information as part of the narration in the response form supplemented with additional supporting information in attachments; and ii) To recognize important differences among the proposals.

If the level of information/data to be used to evaluate each criterion/sub-criterion was not sufficient, then that RFP Respondent was scored less as compared to the RFP Respondent that considered the criteria/sub-criteria provided relevant information in sufficient detail. Each RFP Respondent was evaluated for each of the criteria/sub-criteria listed based solely on the original information that was submitted in response to the RFP. No additional information regarding Operations, Maintenance and Safety was requested from any RFP Respondent in fairness to other RFP Respondents who initially provided information in response to the RFP.

Analysis

The analysis focused on whether the respondent has demonstrated that it has an adequate team with the manpower, equipment, knowledge of the local area, and expertise required to undertake the operation and maintenance of the Project as well as other aspects such as safety, NERC compliance, restoration plan and response time, financial strategy to address catastrophes, etc.

For purposes of the comparative analysis and scoring for the Operations category, the evaluation considered the representations by the respondents regarding adherence to best applicable robustness of operations and maintenance plans and practices proposed for this Project, including but not limited to proposed plans for compliance with NERC requirements as well as safety. The evaluation for the operation category was mostly qualitative, except for the information provided for the criterion safety records, based upon how well the information that was narrated along with the supporting documents and the extent to which it demonstrated Respondent's ability to safely operate, maintain, and increase the availability of the line by quickly restoring the Wolf Creek – Blackberry Project over its life. The resulting point allocation for each RFP Respondent for each criterion is shown in Table 13 below.

The evaluation showed that all respondents have demonstrated to have the capability to adhere to good utility operations and maintenance practices for their respective proposals. However, based on the information provided by each respondent, it was evident that some of the proposals have more well-established organizations and plan processes related to operations and maintenance of the Project than other proposals.

Based on the foregoing analysis and the scoring shown in Table 8, the evaluation pertaining to the operations, maintenance, compliance, reliability, safety, and other aspects listed for the Operations group and its sub-categories revealed no material difference or slight difference among the Proposals A, B, C, and G. Proposals D and E provided far less information to demonstrate Respondent's ability as compared to the other proposals, and provided information that was not relevant for one category for the Maintenance performance/Expertise category.

Proposal F provided relevant information as to how the Project will be integrated into the overall operation and maintenance plans and processes [redacted] Proposal F lacked information addressing operational, maintenance, and safety aspects [redacted] Proposal F also lacked detailed information addressing special considerations [redacted]

It should be noted that the Operations scoring category did not allocate any points for the submitted O&M and A&G expenses as those expenses will be considered under the Rate Analysis category.

Table 13
Operations Point Allocation by Criterion and RFP Respondent

Operations (Operations/Maintenance/Safety) 250 Points *Measures safety and capability of an RFP Respondent to operate, maintain, and restore a transmission facility*	Sub-criteria	Weight	Total Pts	A	B	C	D	E	F	G
3a) Operations	3a.1) Control Center Operations	10%	25	22.5	22.5	25	19.25	19.25	25	25
	3a.2) Reliability Metrics	10%	25	25	25	25	23.25	23.25	15	25
	3a.3) NERC Compliance Process History	10%	25	25	25	23.75	21.88	21.88	25	25
	Sub-Total Criteria Pts	30%	75	72.5	72.5	73.75	64.38	64.38	65	75
3b) Maintenance	3b.1) Storm/Outage and Emergency Response Plan	10%	25	22.5	22.5	25	20	20	15	25
	3b.2) Specialized Maintenance Equipment and Spare Parts	8%	20	16	16	16	15	15	11	18
	3b.3) Maintenance Plans	8%	20	20	20	20	18	18	12	20
	3b.4) Maintenance Staffing/Training	8%	20	20	20	20	18	18	12	19
	3b.5) Maintenance Performance/Expertise	6%	15	15	15	14.25	7.5	7.5	14.25	15
	3b.6) Restoration Experience/Performance	6%	15	15	15	14.25	13.5	13.5	9	15
	Sub-Total Criteria Pts	46%	115	108.5	108.5	109.5	92	92	73.25	112
3c) Safety	3c.1) Internal Safety Program	8%	20	20	20	20	20	20	20	20
	3c.2) Contractor Safety Program	8%	20	18	18	20	20	20	20	20
	3c.3) Safety Plan Similar to This Project and Performance Record	8%	20	20	20	20	18	18	18	18
	Sub-Total Criteria Pts	24%	60	58	58	60	58	58	58	58
	Scoring Category Total	**100%**	**250**	**239**	**239**	**243.25**	**214.38**	**214.38**	**196.25**	**245**

Rate Analysis

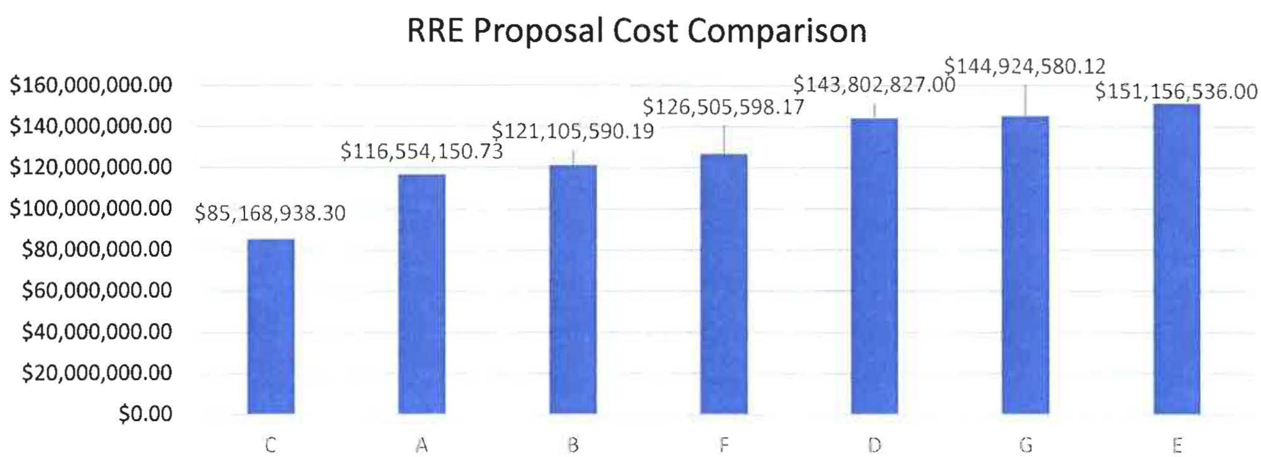
Attachment Y allocates 225 points for this scoring category. Of these total points 101.25 were assigned to the RRE scoring criteria, 101.25 points were assigned to the PVRR scoring criteria and 22.5 were assigned to the Other Attachment Y scoring criteria as illustrated in the table above.

The scoring methodology was based on the criteria listed in the IEP Direction to Respondents document. The scoring process was further defined in the scoring methodology section, as a two-step process for the RRE and PVRR scoring criterion. The first step of this scoring process was the determination of whether a Proposal complied with the RRE and PVRR filing requirements as outlined in the RFP. Those Proposals who did comply with the RRE and PVRR RFP standards were awarded a maximum of 50.625 points out of the 101.25 points for compliance with these filing requirements.

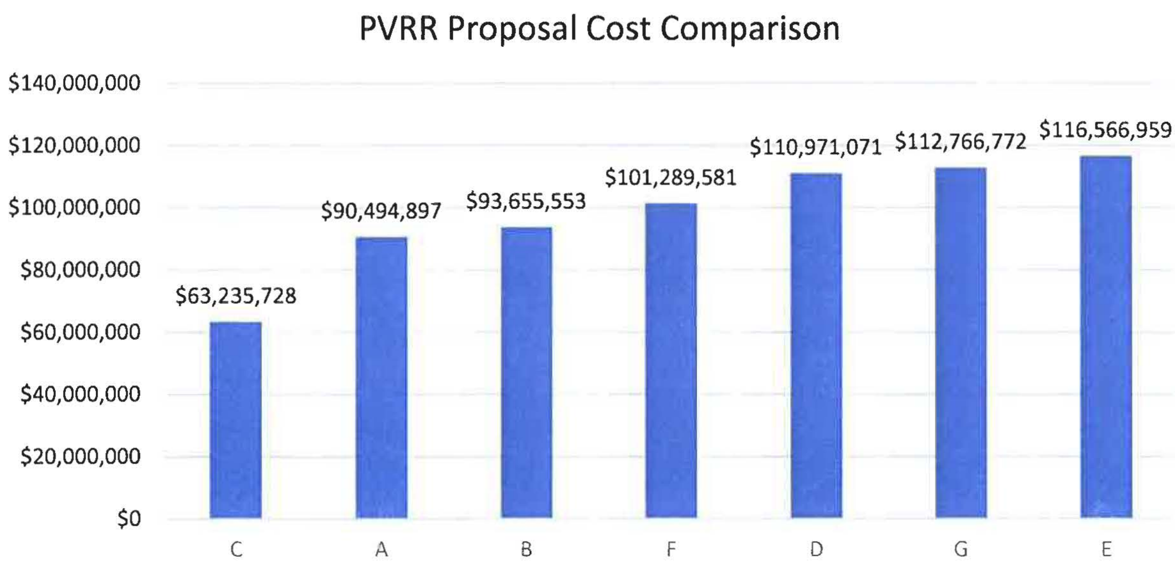
The IEP evaluator reviewed each Proposal's filing for the RRE and PVRR filing requirements and determined that each Proposal did meet the filing requirements for both the RRE and PVRR criteria as outlined in the RFP. Therefore, as part of step one of the scoring process, each Proposal received 50.625 points for the RRE and 50.625 points for the PVRR scoring criteria,

In the second step of the RRE and PVRR scoring methodology process, each Proposal was assigned a percentage of the remaining 50.625 points based on the formula described in Section 2 – Scoring Methodology.

The ranking and scoring of RRE Proposal costs reflects the distribution of the proposals. Table below displays the revenue requirement estimate of each of the Proposals.



The ranking and scoring of PVRR proposal costs reflects the distribution of the proposals with the cost of financing included. Table below displays the present value of the revenue requirement of each of the Proposals.



Once this two-step process was completed, the points awarded for the first step of the scoring process were added to the points awarded for the second step of the scoring process for a combined total RRE and PVRR category score for each Proposal.

The results of this two-step process for each Proposal's RRE and PVRR scoring categories are contained in the table below.

Points for cost cap proposals were allocated based on how the cost caps provided and their respective terms and conditions as shown in the table below.

The resulting point allocation for each RFP Respondent for criteria/sub-criteria in the Rate Analysis category is shown in the table below.

Table 14
Rate Analysis Point Allocation by Criterion and RFP Respondent

Section 4: Rates (Cost to Customer) 225 Pts *Measures an RFP Respondent's and, if applicable, a CU Participant's cost to construct, own, operate, and maintain the Competitive Upgrade over a 40-year period*	**Sub-criteria**	**Weight**	**Total Pts**	**A**	**B**	**C**	**D**	**E**	**F**	**G**
4a) Estimated Total Cost of Project (RFP Response Estimate - RRE)	4a.1) Estimated Total cost of the Project	45%	101.25	87.62	86.23	101.25	80.61	79.15	84.71	80.38
4b) Present Value Revenue Requirement (PVRR)	4b.1) Financing Costs									
	4b.2) FERC Incentives									
	4b.3) Revenue requirements									
	4b.4) Lifetime Cost of the Project to Customers									
	4b.5 Return on Equity									
	Sub-Total Criteria Pts (B)	45%	101.25	86	84.81	101.25	79.47	78.09	82.23	79.01
4c) Other Attachment Y Factors	4c.1) The quantitative cost impact of material on hand, assets on hand, rights-of-way ownership, control, or acquisition									
	4c.2) Cost Certainty guarantee									
	4c.3) Other Comments									
	Sub-Total Criteria Pts (B)	10%	22.5	19.13	19.13	22.5	20.25	20.25	21.38	21.38
	Scoring Category Total	**100%**	**225**	**192.75**	**190.17**	**225**	**180.33**	**177.49**	**188.32**	**180.77**

A more detailed explanation of the point allocation in the Rate Analysis section is included in the Appendix.

Finance

Each Respondent's proposed approach to financing was described in its narration and supporting materials. The Respondents' proposals differed in how cogently and thoroughly they explained and supported their proposed financing plan. The IEP evaluator made comparisons of the strategies and the specific criteria requested in Attachment Y and the RFP for all responses, and looked for the relevance of supporting material. The Respondents that supported their expectations and assumptions were scored higher than the Respondents that did not support their expectations or assumptions.

The strategy and supporting materials criteria provided by the Respondents for Responses A, B, C, F, and G received full points for two or more of the criteria. The total scores for these five proposals were all 90% or higher of the total available points for the Finance category. There were two Responses, D and E that received the full points for only one criterion, with total resulting scores that were not as close to the other five projects. Each proposal's responses and explanation of the allocation of points are described in the Finance section of the Appendix.

Table 15
Finance Point Allocation by Criterion and RFP Respondent

Section 5: Finance (Financial Viability and Creditworthiness) 125 Points *Measures an RFP Respondents and, if applicable, a CU Participant's ability to obtain financing for the Competitive Upgrade.*	Weight	Total Pts	A	B	C	D	E	F	G
A) Evidence of Financing	10%	12.5	12.5	12.5	12.5	11.25	11.25	12.5	12.5
B) Material Conditions	5%	6.25	6.25	6.25	5	5	5	5	5
C) Financial/Business Plan	25%	31.25	28.125	28.125	31.25	25	25	28.125	28.125
D) Pro Forma Financial Statements	15%	18.75	16.875	16.875	15	15	15	18.75	18.75
E) Expected Financial Leverage	5%	6.25	3.125	3.125	5	3.125	3.125	6.25	6.25
F) Debt Covenants	5%	6.25	5.625	5.625	5.625	6.25	6.25	6.25	6.25
G) Projected Liquidity	15%	18.75	18.75	18.75	16.875	9.375	9.375	16.875	16.875
H) Dividend Policy	5%	6.25	5.625	5.625	5	3.125	3.125	6.25	6.25
I) Cash Flow Analysis	15%	18.75	16.875	16.875	16.875	15	15	18.75	18.75
Scoring Category total:	**100%**	**125**	**113.75**	**113.75**	**113.125**	**93.125**	**93.125**	**118.75**	**118.75**

Total IEP Point Allocation

Table 16 shows the summary allocation of points for each scoring category by RFP Respondent.

Table 16
Total IEP Point Allocation by Scoring Category and RFP Respondent

Scoring Results Matrix SPP-RFP-000003 Wolf Creek-Blackberry 345kV						
RFP Proposal	Engineering Design (200pts)	Project Management (200pts)	Operations (250pts)	Rate Analysis (225pts)	Finance (125pts)	Total Score
C	184.00	169.00	243.25	225.00	113.13	934.38
B	189.00	182.00	239.00	190.17	113.75	913.92
A	186.00	182.00	239.00	192.75	113.75	913.50
G	178.00	187.00	245.00	180.77	118.75	909.52
F	182.00	188.00	196.25	188.32	118.75	873.32
E	185.00	179.00	214.38	177.49	93.13	848.99
D	179.00	179.00	214.38	180.33	93.13	845.83
Average Score	183.29	180.86	227.32	190.69	109.20	891.35

Section 4: Incentive Points

Every Respondent to this RFP qualified for and received the incentive points available.

The SPP Tariff, Attachment Y provides that an RFP Respondent that submitted a Detailed Project Proposal (DPP), as defined in Attachment O Section III.8(b), would be eligible to receive 100 incentive points as part of the selection process for a Competitive Upgrade. The process for determining eligible DPPs was determined by SPP staff in accordance with Attachment O of the SPP Tariff and Business Practice 7650. RFP Respondents that were notified of their eligibility for these incentive points were required to document their eligibility as part of their RFP Response. Staff was then required to confirm eligibility and inform the IEP.

Table 17 shows the results of the IEP point allocation with the addition of incentive points. All the RFP Respondents that submitted a proposal on the Wolf Creek - Blackberry project received the 100 incentive points.

Table 17
Total IEP Point Allocation by Scoring Category and RFP Respondent Including Incentive Points

Scoring Results Matrix SPP-RFP-000003 Wolf Creek-Blackberry 345kV

RFP Proposal	RRE	PVRR	Engineering Design (200pts)	Project Management (200pts)	Operations (250pts)	Rate Analysis (225pts)	Finance (125pts)	Total Score	Qualified for Incentive Pts?	Incentive Pts	Grand Total Score
C	$ 85,168,938	$ 63,235,728	184.00	169.00	243.25	225.00	113.13	934.38	Yes	100.00	1034.38
B	$ 121,105,590	$ 93,655,553	189.00	182.00	239.00	190.17	113.75	913.92	Yes	100.00	1013.92
A	$ 116,544,151	$ 90,494,897	186.00	182.00	239.00	192.75	113.75	913.50	Yes	100.00	1013.50
G	$ 144,924,580	$ 112,766,772	178.00	187.00	245.00	180.77	118.75	909.52	Yes	100.00	1009.52
F	$ 126,505,598	$ 101,289,581	182.00	188.00	196.25	188.32	118.75	873.32	Yes	100.00	973.32
E	$ 151,156,536	$ 116,566,959	185.00	179.00	214.38	177.49	93.13	848.99	Yes	100.00	948.99
D	$ 143,802,827	$ 110,971,071	179.00	179.00	214.38	180.33	93.13	845.83	Yes	100.00	945.83
Average Score	$ 127,029,746	$ 98,425,794	183.29	180.86	227.32	190.69	109.20	891.35	N/A	N/A	991.35

Section 5: Recommended RFP Proposal

The IEP unanimously recommends Proposal C as the Recommended RFP Proposal to construct the Wolf Creek-Blackberry 345 kV Transmission Line. Proposal C received the highest point allocation of any RFP Respondent. Proposal C received the highest point allocation in the scoring category of Rate Analysis, which represents the lowest cost to SPP customers, both in the cost to construct and operate. The strength of Proposal C went beyond being the lowest cost. The IEP review found Proposal C was able to make the significant cost savings while scoring within 5 points (out of 200) below the best scored proposal in Engineering Design and just 1.8 points (out of 250) below the highest score in Operations. The IEP recommendation examined how well Proposal C was scored in these vital areas to ensure that the high points received were reflecting a balance across all categories and criteria that determine the value to SPP customers, not just the cost.

The IEP views Proposal C demonstrated that it offers capabilities and processes that can deliver a successful project, that the proposed designs are robust and that the resulting costs are competitive. This recommendation reflects particular strengths of Proposal C, noted below.

- Proposal C provides very substantial savings to SPP customers with a net present value of the revenue requirements tens of millions of dollars lower than other proposals
- Proposal C includes design and materials solutions not offered by other Respondents, including the use of the highest thermal-rated conductor of any of the proposals.
- Proposal C demonstrated a strong procurement process and team that manages vendor relationships and leverages economies of scale to secure most favorable terms.
- Proposal C draws on resources of its parent and affiliated companies to ensure successful delivery of the Project. [redacted]
- The proposed construction schedule included significant time float, enabling the Respondent to offer a guaranteed schedule for the Project, and an anticipated in-service date [redacted]
- Proposal C included well-defined construction cost estimates from a detailed and structured review process used over many years and many projects. The proposal provides cost caps [redacted]
- Proposal C provided relevant agreements showing the preparedness of the Respondent to take on the required operations and maintenance responsibilities.
- Proposal C provided specific preventive and predictive maintenance plans specific to this project based on principles and examples of statistical process controls to determine appropriate frequency and the extent of future maintenance activities.
- [redacted] The Respondent indicated established switching coordination, planned outage and operating coordination experience and protocols with SPP-member utilities.

Section 6: Recommended Alternate RFP Proposal

The IEP is tasked with developing "a single recommendation for the SPP Board of Directors consisting of its recommended RFP Proposal and an alternate RFP Proposal for each Competitive Upgrade."[4] Further, Attachment Y recognizes that "[t]he RFP Proposal with the highest score may not always be recommended."[5] As explained in Section 5 of this report, the IEP unanimously recommended Proposal C, which was allocated the highest number of points, as well as other positive attributes as detailed in the previous section.

Table 17 lists the Proposals and their corresponding composite points by scoring category and in sum as determined by the IEP prior to the addition of any applicable Incentive Points. Proposal B received the second highest point allocation. The strengths of Proposal B were spread across all the categories. This proposal scored the highest points on Engineering Design, and third in the Project Management, Operations, Rate Analysis, and Finance categories.

Proposal B has the second highest total score (slightly higher than Proposal A) and in addition merits selection over Proposal A by having a larger size conductor than Proposal A. A larger conductor leads to higher power transfer capacity and lower losses. Proposals A and B were submitted by the same Respondent.

As a result of the scoring and the assessment of how the points were scored, the IEP unanimously recommends SPP consider Proposal B as the preferred alternate. In addition, the IEP assessment indicated that Respondent submitting Proposal B is viewed as having the capability and experience to construct the Project successfully.

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[4] Southwest Power Pool – Open Access Transmission Tariff, Sixth-Revised Volume No. 1 – Attachment Y Transmission Owner Designation Process – Attachment Y, Section III at 20.
[5] *Id.* at 39.

INDUSTRY EXPERT PANEL TRANSMISSION PROVIDER PUBLIC REPORT

APPENDIX-FINAL

RFP-000003
Wolf Creek-Blackberry 345kV
October 12, 2021

Appendix Table of Contents

Section 1: IEP Direction to Respondents

IEP Direction to Respondents - Published to spp.org December 21, 2020

SPP Southwest Power Pool

IEP DIRECTION TO RESPONDENTS

RFP# SPP-RFP-000003

WOLF CREEK-BLACKBERRY 345 KV

Published on December 21, 2020
This document was produced by a team of the Independent Expert Panel for the Wolf Creek – Blackberry 345 kV project.

SPP has empaneled an Independent Expert Panel (IEP) team to work through the Transmission Owner Selection Process for the Wolf Creek - Blackberry 345 kV Transmission Line (the "Project"). The IEP team has met to plan its work effort and evaluated how it plans to score the proposals it receives from Respondents for the Project. This document explains the scoring criteria and areas of emphasis as required by the SPP Strategic Planning Committee and Board of Directors, especially as the scoring criteria and areas of emphasis may differ from those used for the previous two Competitive Upgrade projects.

The evaluation of each Respondent's proposal will be based on the information provided and the extent to which the proposal demonstrates the Respondent's ability to complete and commission the Project within the scope, proposed budget, and schedule, safely and with high quality. The evaluation will judge how well the Respondent fully articulates, in a concise and complete form, its expertise, capabilities, and relevant experience in each area covered by the Request for Proposal (RFP) and associated RFP Response Form.

Given that one terminal of the Project will connect to a substation at the Wolf Creek nuclear plant site, Respondents should discuss in each section of their proposals any additional costs, regulatory requirements, or other considerations that may result from this unique aspect of the Project. The Project Management and Operations sections in this guidance document already identify several specific issues that should be addressed in this regard. To the extent that there are additional impacts in these or any of the other sections, Respondents should identify them as appropriate.

While each section of Respondents' proposals will be evaluated and scored separately, the IEP team will also look at each proposal in its entirety, considering interrelationships between each section that could alter the final overall evaluation. For example, the lowest cost proposal in the Rate Analysis section may be the result of a lower quality design or inferior equipment choice in the Engineering Design section, or less than robust plans in the Project Management and Operations sections.

SECTION 1: ENGINEERING DESIGN (RELIABILITY/QUALITY/GENERAL DESIGN), 200 POINTS

MEASURES THE QUALITY OF THE DESIGN, MATERIAL, TECHNOLOGY, AND LIFE EXPECTANCY OF THE COMPETITIVE UPGRADE.

Overall engineering/design of the Project will play a large role in evaluation of Respondents' proposals. Compliance with the SPP Minimum Transmission Design Standards is required. Respondents should provide their plan for compliance with other requirements such as those of the Wolf Creek Nuclear Operating Company, Nuclear Regulatory Commission (NRC), etc.

Respondents should describe relevant experience designing similar projects and comment on the results of these projects.

Knowledge of and compliance with SPP planning standards, applicable industry codes, and regulatory requirements will have the greatest importance in scoring Respondents' proposals, because they impact the conductor, structure, and foundation designs.

Performance over the service life of the assets also will have significant impact on the scoring because they address the safety, reliability, availability, and quality of the transmission line.

Design staff experience should be addressed by identifying the specific resources in the Organization Chart, by experience, capabilities, and availability that will be applied on the Project's different phases, and include resumes of key personnel.

Scoring for line losses will be based on the line-rating capacity, line geometry, impedance/resistivity and reactance, and conductor type selection. Loss calculation methods are discussed in the RFP in a footnote on page 9. Calculations should be provided in the Response Excel document in 1A.14.

Scoring for the estimated life of the Project will be based on the proposed service-life duration and its impact on the reliability and availability of the transmission line to perform its objective.

In addition to the design itself, Respondents should describe how Engineering will be engaged in Procurement, including approval of materials, as well as in on-site presence during Construction.

SECTION 2: PROJECT MANAGEMENT (CONSTRUCTION PROJECT MANAGEMENT), 200 POINTS

MEASURES AN RFP RESPONDENT'S EXPERTISE IN IMPLEMENTING CONSTRUCTION AND COMMISSIONING OF THE COMPETITIVE UPGRADE.

While all the categories of Project Management as listed in the RFP and RFP Response Form are important and will be scored and evaluated, the categories that pose the most risk to the successful and timely completion of this Project are the Environmental and ROW Acquisition categories, without which the other aspects of the Project cannot proceed.

<u>Environmental</u>

- Respondents should provide a well-defined environmental review and permitting process, and elaborate on their first-hand knowledge of and experience in evaluating all relevant environmental factors, especially those related to this Project as described in the RFP Response Form. This should include discussion of factors reasonably expected to be encountered on the proposed route (e.g., endangered species, cultural areas, etc.).

- Respondents should give particular attention to the development and execution of specific plans for addressing these factors in the affected states and municipalities and securing the necessary regulatory approvals.

<u>Rights of Way Acquisition</u>

- Equally important is the Respondent's knowledge of and experience with various transmission line siting approval processes. Respondents should provide instances in the last five years in which they have gained the necessary approvals for ROW acquisition, whether through the exercise of eminent domain or other means.

- Respondents should also provide copies of any documents that demonstrate that it has control of any ROW segments related to this Project. If the Respondent does not have eminent domain rights, it should present its plan and experience for gaining the necessary ROW approvals.

Procurement

- Supply chain management has taken on increased importance with respect to equipment ordered to complete a project, especially if some equipment is planned to be purchased from non-domestic sources. To the extent this is an issue regarding the equipment needed for this Project, Respondents should indicate how they plan to address supply chain management issues.
- The evaluation of each Respondent's proposal will consider the quality of the material providers selected, and the Respondent's prior relationships and evidence of warranties on all material.
- Respondents should provide their QA/QC process for material and equipment procurement, including review of each manufacturer's quality processes and anticipated factory inspections.

Project Development Schedule, Scope, Time to Construct, and Commissioning

- Respondents should provide their detailed processes and plans for managing all aspects of Project development and scheduling, including key milestones for the time to construct and commission the Project.
- Respondents should cite their experience and track record in developing and following a critical path schedule for this Project, including how they have addressed unforeseen obstacles encountered in the past on projects of similar scope and magnitude.
- Respondents should reflect in their Project development schedule a clear understanding of the requirements for access to and performance of work on the Wolf Creek property and within the Wolf Creek substation to connect the new 345 kV line and associated fiber optic communications circuits at the designated dead-end structure.
- Respondents should describe their plan for coordination with the Wolf Creek substation owner, the Wolf Creek Nuclear Operating Company, and the NRC, as necessary, to evaluate any crossing(s) the new 345 kV line will make over or under existing lines out of the Wolf Creek substation. In addition, Respondents should describe any special system studies required to evaluate the impacts of such crossings, including the impact of potential multi-line outages. Respondents should also document any potential restrictions to construction during certain times of the year or during scheduled nuclear plant outages.

Construction

- Respondents should provide specific evidence of significant prior experience in managing the construction of projects similar in scope and magnitude. Respondents should explain how they plan to deploy the necessary support staff, field crews, and material handling resources. Respondents should also describe the safety protocols that will be followed during the construction process. In order to demonstrate its past safety performance, Respondents should provide their Experience Modification Rate (EMR) for previous projects.

- Respondents should provide a Construction Project Organization Chart. Respondents should provide resumes of those expected to be in key leadership roles in managing all aspects of construction, including QA/QC process, record keeping, reporting, and their approach to addressing issues that may be encountered.

SECTION 3: OPERATIONS (OPERATIONS/MAINTENANCE/SAFETY), 250 POINTS

MEASURES SAFETY AND CAPABILITY OF A RFP RESPONDENT TO OPERATE, MAINTAIN, AND RESTORE THE COMPETITIVE UPGRADE.

The success of the Project within Operations will be reflected in its operation, maintenance, and safety aspects. Scoring will use the criteria in Attachment Y grouped within these categories:

- Operations - control center operations, proposed plan to incorporate this Project into a control center, real time monitoring and control, reliability metrics and NERC reliability compliance-process history;

- Maintenance - storm/outage response plan, specialized maintenance equipment and spares, maintenance plans, maintenance staffing/training, maintenance experience and historical performance, and restoration experience and historical performance. Financial strategy for the Project replacement/rebuilds following catastrophic failures will be evaluated as part of the storm/outage response plan; and

- Safety - internal safety programs, contractor safety programs, and safety plans and historical records, including their most recent Experience Modification Rate (EMR).

Points for Section 3: Operations Evaluation Criteria will be allocated to these three categories described above and further subdivided to their subcategories. A slightly higher allocation of available points will be made to the maintenance criterion, followed by operations and safety criteria.

This point allocation is intended to emphasize that successful operation: i) requires lifetime commitment to the Project, ii) recognizes that timing, financial strategy, and expertise are relevant for repairs and storm recovery including replacement/rebuilds following catastrophic failures, iii) recognizes that there is a difference between what should be done in advance to improve reliability and resiliency as compared to what should be done in response to external events, and iv) recognizes that the Project must be operated in a safe manner throughout its life cycle.

Because part of the line will be located within the plant property requiring security clearance for access, Respondents should describe their plans for gaining access to the Wolf Creek nuclear power plant property to perform routine line maintenance or emergency repairs. If such maintenance or emergency repairs are to be performed by others, Respondents should describe their plans to arrange for such activities.

SECTION 4: RATE ANALYSIS (COST TO CUSTOMER), 225 POINTS

MEASURES AN RFP RESPONDENT'S COST TO CONSTRUCT, OWN, OPERATE, AND MAINTAIN THE COMPETITIVE UPGRADE OVER A FORTY (40) YEAR PERIOD.

The scoring in the Rate Analysis section will use the criteria in Attachment Y grouped within three primary evaluation categories: Total Cost of The Project - RFP Response Estimate (RRE); Present Value Revenue Requirement (PVRR); and Other Attachment Y factors which could reduce the cost and risk of the Project.

Points for the first two evaluation categories (RRE and PVRR) will be awarded based on the lowest cost numbers (i.e., the lower the cost numbers for RRE and PVRR, the higher the points awarded in each of these categories). The scoring in each of these categories could also be conditioned on the cost proposal meeting the requirements of the other IEP evaluation sections.

The PVRR calculation includes the following Attachment Y criteria:

- RFP Response Estimate (RRE) total (Tab 2B cell C36 of the Excel Workbook)
- Financing costs (Response Form 4A.2)
- FERC incentives (Response Form 4A.3)
- Revenue Requirements (Response Form 4A.4) - Provide an estimated present value revenue requirement (PVRR) for this RFP Proposal by completing Tabs 3-3G of the RFP Response Form Excel Workbook
- Lifetime cost of the Project to customers (Response Form 4A.5)
- Return on Equity (Response Form 4A.6)

The third and final evaluation category will have a lesser number of points assigned to it than the other two categories. Points will be awarded based on a detailed, quantitative response that demonstrates a reduction in the cost risk of the Project, including the following Attachment Y criteria:

- The quantitative cost impact of material on hand, assets on hand, rights-of-way ownership, control, or acquisition (Response Form 4A.7)
- Cost certainty guarantee (Response Form 4A.8)
- Other Comments (Response Form 4A.9)

SECTION 5: FINANCE (FINANCIAL VIABILITY AND CREDITWORTHINESS), 125 POINTS

MEASURES AN RFP RESPONDENT'S ABILITY TO OBTAIN FINANCING FOR THE COMPETITIVE UPGRADE.

Financial viability and creditworthiness are ultimately assessed in the market, based on projections of future circumstances. Proposals presented to SPP must provide projections and assumptions for inputs and responses to the criteria described in Attachment Y. All of the criteria listed in Attachment Y under this section will be evaluated and scored, with recognition that assumptions used in the Respondents' analyses can alter the results of those analyses.

To establish the viability and creditworthiness of the proposals, and the analyses requested, attention will be given to the assumptions made for inputs the Respondent has used. The bid that can support the assumptions for external factors and expectations for other inputs to this section will be scored higher.

Section 2: Requests for Information

Requests for Information Issued During IEP Evaluations

Request for Information (RFI): A request for information was issued to one Respondent asking for clarification of how their design provides primary and redundant communications paths as stated in the RFP. The response was received and evaluated as fully acceptable and compliant.

Section 3: Documentation of Points Allocation by Scoring Category

I: Engineering Design

For the Engineering Design evaluation process, all seven proposals were carefully reviewed, looking at all Engineering related documents. This included the RFP Response Form (Proposal word document), the RFP Response Form Workbook, all associated engineering attachments, and other Proposal information. For those proposals that included a Design Criteria document, those were printed hard copy as an aid in reviewing and comparing across the proposals. Notes were taken during the review of each proposal, leading up to capturing significant relevant data/features/attributes of all seven proposals on a large excel spreadsheet, organized to compare each proposal in a side by side manner. This Side by Side comparison included information from the RFP Response Form, the RFP Response Form Workbook (18 of 24 engineering related line items), and the associated engineering attachment (on average 20 plus attachments per proposal).

The Side by Side comparison tool including all six criteria, and associated sub-criteria:

1A.1 Type of Construction (Wood, Steel, Design Loading, etc.)
- Design Loading Criteria, NESC Assumptions, SPP MTDS
- Foundations - score included in Design Loading Criteria
- Conductor Type/Name, Ampacity, Number of sub conductors, Line Emergency MVA rating
- Shield Wire Type/Name, number of Shield Wires, Size of Wire, Number of Fibers
- Structure Configuration, Quantity of Tangent, DE, and Storm Structures
- Insulators, Lightening/BIL
- Dampers
- Markers

1A.2 Losses (Design Efficiency)
1A.3 Estimated Life of Construction
1A.4 Reliability/Quality Metrics, Materials, ISO Cert, Design QA/QC
1A.5 Other - Design Experience
1A.6 Other – Comments

While this Side by Side spreadsheet tool was useful, during the development of scoring, the full breadth of the provided proposal engineering documents was used and referred to frequently.

Another tool used in the evaluation was the Scoring Guideline. This was developed earlier by the full IEP Panel and working in tandem with the Side by Side comparisons excel sheet, was used to develop scores for each proposal in each criteria/sub-criteria.

Scoring Guideline Point Designation for Engineering Design

Section 1: Engineering Design (Reliability/Quality/General Design) 200 Pts *Measures the quality of the design, material, technology, and life expectancy of the Competitive Upgrade*	**Sub-criteria**	**Weight**	**Total Pts (200)**
1a) Type of Construction (Wood, Steel, Design Loading, etc.)	1a.1) Design Loading Criteria	10%	20
	1a.2) Conductor Type/Name, Ampacity, Number of sub conductors	12%	24
	1a.3) Shield Wire Type/Name, Number of Shield Wires, Size of Wire	5%	10
	1a.4) Structure Configuration	18%	36
	1a.5) Insulators	6%	12
	1a.6) Dampers	4%	8
	1a.7) Markers	3%	6
	Sub-Total Criteria Pts	58%	116
1b) Losses (Design Efficiency)		10%	20
1c) Estimated Life of Construction		10%	20
1d) Reliability/Quality Metrics		10%	20
1e) Other - Design Experience		10%	20
1f) Other - Comments		2%	4
	Scoring Category Total	**100%**	**200**

An overall Scoring Methodology for assigning scores was also developed by the full IEP Panel prior to receiving proposals:

0% - non-compliant
50% - meets minimum
Up to 80% - good
Up to 90% - better
Up to 100% best

Scoring was the result of utilizing a combination of the Notes taken during the review, the excel Side by Side comparison, the Scoring Guideline, the Scoring Methodology, and frequent reference back to the full proposal. The overall Engineering Design scores are summarized here, followed by more in-depth discussion of how these scores were derived.

Section 1: Engineering Design (Reliability/Quality/General Design) 200 Pts *Measures the quality of the design, material, technology, and life expectancy of the Competitive Upgrade*	**Sub-criteria**	**Weight**	**Total Pts**	**A**	**B**	**C**	**D**	**E**	**F**	**G**
1a) Type of Construction (Wood, Steel, Design Loading, etc.)	1a.1) Design Loading Criteria	10%	20	20	20	18	19	19	19	19
	1a.2) Conductor Type/Name, Ampacity, Number of sub conductors	12%	24	20	22	22	20	24	19	19
	1a.3) Shield Wire Type/Name, Number of Shield Wires, Size of Wire	5%	10	10	10	10	10	10	9	9
	1a.4) Structure Configuration	18%	36	34	34	32	29	29	36	32
	1a.5) Insulators	6%	12	11	11	10	12	12	11	11
	1a.6) Dampers	4%	8	8	8	8	8	8	8	8
	1a.7) Markers	3%	6	6	6	6	6	6	6	6
	Sub-Total Criteria Pts	58%	116	109	111	18	104	108	108	104
1b) Losses (Design Efficiency)		10%	20	17	18	18	17	19	16	16
1c) Estimated Life of Construction		10%	20	19	19	18	18	18	18	18
1d) Reliability/Quality Metrics		10%	20	19	19	20	17	17	18	18
1e) Other - Design Experience		10%	20	19	19	19	20	20	18	18
1f) Other - Comments		2%	4	3	3	3	3	3	4	4
	Scoring Category Total	**100%**	**200**	**186**	**189**	**184**	**179**	**185**	**182**	**178**

1A.1 Type of Construction (Wood, Steel, Design Loading, etc.)

Design Loading Criteria, NESC Assumptions, SPP MTDS (max 20 points) – all proposals met or exceeded in this area. All met NESC Codes, and all met or exceeded SPP Minimum Transmission Design Standards. Five of the Proposals included a Design Criteria, while two included this information within their Proposal. In the area of Design Loading Criteria, all seven Proposals were similar, with only slight variations. For example, there was some variation across the proposals in the areas of the extreme wind case used (ranging from 90 mph to 105 mph), and the broken conductor case used. With such consistency across all proposals in this category, evaluating good/better/best/ was very "tight". Thus, the scoring across this category varied only slightly, ranging from 18 to 20 points.

Foundations - score included in Design Loading Criteria – Most proposals utilized a direct imbedded type foundation, other proposals utilized drilled pier with anchor bolt/self-supporting foundations allowing, for the elimination of down guys, which was seen as a positive. All proposals had a comprehensive Geotech Study, although the Geotech data used varied from utilizing an area project built several years ago to one proponent who actually took soil borings along their proposed route Evaluation of Foundations and results were included in the above Design Criteria score, and led to some of the variance between 18 to 20 points.

For Type of Construction and the RFP requirement to meet or exceed the SPP Minimum Transmission Design Standards, a comparison was made for all seven proposals for compliance. All seven proposals met these standards previously published by SPP and pasted here for reference:

SPP Minimum Transmission Design Standards, Rev 2, December 2016

General

Transmission lines shall be designed to meet all applicable federal, state, and local environmental and regulatory requirements.

Electrical Clearances

Design clearances shall meet the requirements of the NESC. To account for survey and construction tolerances, a minimum design margin of 2 feet shall be applied to ensure the NESC clearances are maintained after construction. This margin shall be applied to conductor-to-ground and conductor-to-underlying or –adjacent object clearances, but need not be applied to conductor-to-transmission structure clearances. These clearances shall be maintained for all NESC requirements and during the ice with concurrent wind event as defined in the Structure Design Loads Section. In regions susceptible to conductor galloping, phase-to-phase and phase-to-shield wire clearances during these conditions shall be considered.

Sufficient space to maintain OSHA minimum approach distances in place at the date of project approval, either with or without tools, shall be provided. When live-line maintenance is anticipated, designs shall be suitable to support the type of work that will be performed (e.g., insulator assembly replacement) and the methods employed (i.e., hot stick, bucket truck, or helicopter work, etc.).

Structural Design Loads

All structure types (dead ends, tangents, and angles), insulators, hardware, and foundations shall be designed to withstand the following combinations of gravity, wind, ice, conductor tension, construction, and maintenance loads. The magnitude of all weather-related loads, except for NESC *or other legislated loads shall be determined using a 100 year mean return period and the basic wind speed and ice with concurrent wind maps defined in the ASCE Manual of Practice (MOP) 74. With the exception of the NESC or other legislated loads that specify otherwise, overload factors shall be a minimum of 1.0.*

Loads with All Wires Intact

- *NESC Grade B, Heavy Loading*
- *Other legislated loads*
- *Extreme wind applied at 90º to the conductor and structure*
- *Extreme wind applied at 45º to the conductor and structure*
- *Ice with concurrent wind*
- *Extreme ice loading*

Unbalanced Loads (applies to tangent structures only)

- *Longitudinal loads due to unbalanced ice conditions, considering 1/2"radial ice, no wind in one span, no ice on adjacent span, with all wires intact at 32º Fahrenheit final tension. This load case does not apply to insulators; however, insulators must be designed such that they do not detach from the supporting structure.*
- *Longitudinal loads due to one broken ground wire or one phase position (the phase may consist of multiple sub-conductors). For single conductor phases, use 0" ice, 70 mph wind, 0º F and for multi-bundled phases use no wind, 60º F. Alternatively, for lines rated below 200 kV, provide stop structures at appropriate intervals to minimize the risk of cascading failures. This load case does not apply to insulators; however, insulators must be designed such that they do not detach from the supporting structure.*

Construction and Maintenance Loads

- *Construction and maintenance loads shall be applied based on the recommendations of ASCE MOP 74.*

Structure and Foundation Design

Structures and foundations shall be designed to the requirements of the applicable publications:

- *ASCE Standard No. 10, Design of Latticed Steel Transmission Structures*
- *ASCE Standard No. 48, Design of Steel Transmission Pole Structures*
- *ASCE Manual No. 91, Design of Guyed Electrical Transmission Structures*
- *ASCE Manual No. 104, Recommended Practice for Fiber-Reinforced Polymer Products for Overhead Utility Line Structures*
- *ASCE Manual No. 123, Prestressed Concrete Transmission Pole Structures*
- *ANSI 05-1, Specifications and Dimensions for Wood Poles*
- *IEEE Std. 751, Trial-Use Design Guide for Wood Transmission Structures*
- *ACI 318 Building Code Requirements for Structural Concrete and Commentary*

Proper clearances with design margins shall be maintained under deflected structure conditions. A geotechnical study shall be the basis of the final foundation design parameters.

Conductor Type/Name, Ampacity, Number of sub conductors, Line Emergency MVA rating (max 24 points) – Conductor ranged from 1113 Finch up to 1590 Falcon. Most proposals included a very comprehensive Conductor Selection Study, demonstrating a significant level of effort to bring forward conductors best suited for the project requirements. All Proposals met/exceeded the MTDS 3000 Amps Emergency Rating requirement. From an engineering perspective, the large conductor was seen as a positive (recognizing that design efficiency/cost would be considered in the Rate Analysis section). Scores ranged from 19 (Good) to 21 (Better) to 24 points (Best).

Proposal	Conductor	Configuration
A	[redacted]	
B		
C		
D		
E		
F		
G		

For Conductor and the RFP requirement to meet or exceed the SPP Minimum Transmission Design Standards, a comparison was made for all seven proposals for compliance. All seven proposals met these standards previously published by SPP and pasted here for reference:

SPP Minimum Transmission Design Standards, Rev 2, December 2016

Phase Conductors

The minimum amperage capability of phase conductors shall meet or exceed the values below, unless otherwise specified by SPP. If otherwise specified by SPP, the SPP value govern. The amperage values shown in the table shall be considered to be associated emergency operating conditions.

The emergency rating is the amperage the circuit can carry for the time sufficient transfer schedules, generation dispatch, or line switching in an orderly manner with of life to the circuit involved. Conductors shall be selected such that they will lose percent of their original strength due to anticipated periodic operation above the normal

Voltage (kV) Emergency Rating: 345 kV 3,000 Amps

The conversion from conductor ampacity to conductor temperature shall be based Criteria 7.2.; however, the RFP will specify the design wind speed and direction

A comparison taken from the proposal Response Workbook, for all seven proposals:

Proposal	Conductor Type	Conductor Size	Ampacity	Summer Emergency MVA
C	[redacted]	[redacted]	[redacted]	[redacted]
E	[redacted]	[redacted]	[redacted]	[redacted]
B	[redacted]	[redacted]	[redacted]	[redacted]
D	[redacted]	[redacted]	[redacted]	[redacted]
A	[redacted]	[redacted]	[redacted]	[redacted]
F	[redacted]	[redacted]	[redacted]	[redacted]
G	[redacted]	[redacted]	[redacted]	[redacted]

Shield Wire Type/Name, number of Shield Wires, Size of Wire, Number of Fibers (max 10 points)
All proposals utilized two shield wires, with the number of fibers ranging from 40 to 72 per SW. The use of repeater stations was called out in some of the proposals, ranging from installation of two repeater stations to "our study indicates repeater stations are not needed [redacted]". The RFP requirement of dual communication paths was evaluated in this category and was accomplished by all proposals. Scoring ranged from 9 to 10 points.

SPP Minimum Transmission Design Standards, Rev 2, December 2016

Shield Wire
Fiber shall be installed on all new transmission lines being constructed, consisting of OPGW, underground fiber, or ADSS fiber. Where there are multiple shield wires and OPGW is utilized, only one need be OPGW. The shield design shall be determined based on the anticipated fault currents generating from the terminal substations. Adequate provisions shall be made for fiber repeater redundancy as well as power supply redundancy at each repeater. The minimum number of fiber strands per cable shall be 36.

Structure Configuration, Quantity of Tangent, Dead End, and Storm Structures (max 36 points) – all proposals were based on a single pole structure, either steel or spun concrete [redacted]. The use of spun concrete poles was not evaluated as a plus or minus compared to steel poles, as both materials have been in use for over 25 years and both have performed well with good reliability. The number of tangents, dead end/storm, and transposition structures varied across the proposals. Total structure count ranged from 470 to 573 and Dead End structure count ranged from 30 to 46. In general, from an engineering perspective, more structures and dead ends were considered better (recognizing design efficiency/cost is considered in the Rate Analysis section). One proposal had a design utilizing self-supporting structures/no down guys which was seen as a positive. Some proposals were clear that their design supported live line maintenance. Scoring ranged from 29 to 36 points.

Proposal	Total	Tang/Light Angle	Dead Ends/Storm
A	[redacted]		
B			
C			
D			
E			
F			
G			

Insulators, Lightening/BIL (max 12 points) – All proposals utilized polymer type insulators. Configuration varied from braced post to davit arm with suspension Vee strings, to davit arm with I String suspension. BIL ranged from 1439 to 1841, with some differences between dead ends and tangent structures. Scores ranged from 10 to 12.

SPP Minimum Transmission Design Standards, Rev 2, December 2016

Insulation Coordination, Shielding, and Grounding
Insulation, grounding, and shielding of the transmission system (line and station) shall be coordinated between the Designated Transmission Owner and the Transmission Owner(s) to which the project interconnects to ensure acceptable facility performance.

All metal transmission line structures, and all metal parts on wood and concrete structures shall be grounded. Overhead shield wires shall also be grounded, or a low impulse flashover path to ground shall be provided. Grounding requirements shall be in accordance with the NESC.

Dampers (max 8 points) – all proposals utilized the same conductor damper and shield wire vibration damper. All had a max score of 8 points.

Markers (max 6 points) – all proposals were very similar, and all had a max score of 6 points

1A.2 Losses (Design Efficiency) (max 20 points) – Proposals and supporting attachments varied across all the proposals. Some clearly stated they utilized the RFP stated requirement to use the criteria listed in the SPP MTDS. Some listed calculated losses in NPV, some in MWh/Yr., and some simply in MW. For this RFP, sufficient information was provided to allow for a fair comparison across all the proposals. In addition to the provided data on losses, the size of the conductor was considered. In general, lower losses were considered better. Scores ranged from 16 to 19 points.

SPP Minimum Transmission Design Standards, Rev 2, December 2016

The emergency rating is the amperage that the circuit can carry for the time sufficient for adjustment of transfer schedules, generation dispatch, or line switching in an orderly manner with acceptable loss of life to the circuit involved. Equipment shall be rated in accordance with SPP Planning Criteria 7.2.

Planning Criteria Section 7.2.1.3

In ANSI/IEEE C57.91, a 65°C rise transformer can operate at 120% for an 8 hour peak load cycle and will experience a 0.25% loss of life. If a 65°C rise transformer experiences 4 incidents where it operates at or below 120% for an 8 hour peak load cycle, it will still be within the target of 1% loss of life per year. In ANSI/IEEE C57.91, a 55°C rise transformer can operate at 123% for an 8 hour peak load cycle and will experience a 0.25% loss of life. Likewise, if a 55°C rise transformer experiences 4 incidents where it operates at or below 123% for an 8 hour peak load cycle, it will still be within the target of 1% loss of life per year.

RFP Footnote under Tab 1A.2

Average annual ambient temperature method can be used to calculate losses. Alternatively, losses can be calculated at rated power in MVA without a temperature using the Proposal's line resistance parameters R and X:
*Current i = (MVA*1000)/(kV*sqrt3)*
*Real Power Losses P = i^2*R*
*Reactive Power Losses Q = i^2*X*

1A.3 Estimated Life of Construction (max 20 points) – all designs were in alignment with industry best practices and provided a robust and durable asset. Some proposals utilized a Mish core which was seen as a slight positive. All proposals were in agreement of an estimated life of 80 – 100 years for the structures, and 40 – 50 years for the polymer insulators. Some proposals included a corrosion study for the foundations, and some were clear they had included ground sleeves on the poles. Since all proposals utilized polymer insulators; and none utilized ceramic insulators, no one received the maximum of 20 points. Points ranged from 18 to 19 points (good/better).

1A.4 Reliability/Quality Metrics, Materials, ISO Cert, Design QA/QC (max 20 points) – all Design Firms provided a high-quality QA/QC and independent check process for the engineering deliverables. [redacted] Return periods varied from 200 years to 300 years. Most proposals included a Lightning Study and flashover rates less than 1<100 miles/year. While not always clearly stated, all proposals include storm structure approximately every 5 miles. Some proposals utilized galvanized poles, with coating thickness in alignment with industry best practices. From the Rates Section, the amount of maintenance expenditure per year had some influence on this category. Scores ranged from 17 to 20 points.

Materials selected and presented in the Proposals were the outcome of the Engineering Design. All materials were industry typical and standard and similar to materials used on countless similar transmission line projects across the industry for many years. That is, all the Proposals were based on tried and true materials in use and proven over many years of successful service in the US Grid.

From a Project Reliability / Quality point of view, Engineering and Design were the primary evaluation focus, but installation and teamwork between the Engineer and the Constructor was considered.

Proposal	Engineer	Contractor
A & B	[redacted]	
C		
D & E		
F & G		

1A.5 Other - Design Experience (max 20 points) – A total of four different design firms were engaged in the seven proposals. All the Firms were considered best in class in the industry. All have completed thousands of miles of successful projects, with some maybe more than others. All have been doing transmission line design for decades. All have access to a robust pool of resources. Resumes were provided. Once detailed design actually starts, there is always some potential for the design leads assigned may vary from the proposed design leads. The overall proposal – Engineering related documents – were complete, with some Firms providing a more complete set of attachments, and some exceeding what might normally be expected. Examples include the areas of a well-organized Design Criteria, obtaining actual soil borings, comprehensive Geotech Study, Lightning Study, Conductor Selection Study, video of the proposed route, with some proposals including other studies above and beyond the norm. Scores ranged from 18 to 20 points.

Proposal	Firm
A & B	[redacted]
C	
D & E	
F & G	

1A.6 Other (max 4 points) – information in the proposals were more in the areas of Project Management and Operations and less in the area of Engineering. The discussion of repeaters was included here which was taken into consideration in the Shield Wire scoring. In general, all Respondents invested significant effort into their submissions. For example, all brought their design to a "30% design" level for developing their full proposal. Scores ranged from 3 to 4.

In general, all proposals were of high quality and completeness, and provided the information as to evaluate across all seven proposals. There was very little variation across the proposals, thus the spread from high to low score was small.

II: Project Management

General Comments on All Proposals - Project Management

Environmental

All respondents have retained experienced contractors/consultants with first-hand knowledge and experience with the area expected to be traversed by the new line as well as familiarity with the various regulatory/permitting processes and agencies in Kansas and Missouri, which experience will assist in routing and environmental permitting. All proposals provided well-defined plans for addressing all relevant environmental and cultural issues unique to the region, including mitigation plans to address risk associated with the selected route.

ROW

All respondents have extensive Land Acquisition Plans (including timelines) and have engaged experienced contractors to assist in acquiring the necessary easements for the line itself as well as for additional property needed for site access and construction.

All respondents and their contractors have strong preference for fair market pricing of properties needed for the Project, and plan for several open house events to address landowner issues.

All respondents have experience and plans for obtaining eminent domain rights, if necessary; all plan to use it as a last resort.

Procurement

All Respondents provided comprehensive Procurement and Project Management Plans as called for in the RFP, and plan to use qualified/experienced staff and contractors.

All Respondents have described their planned QA/QC program and process with respect to material and equipment procurement, including inspections of materials and equipment at vendors' sites and at construction sites.

All Respondents indicate their plan to use qualified and experienced material and equipment providers who are expected to provide evidence of warranties on all material and equipment.

Project Development Schedule/Scope

All Respondents have provided the required schedules and "no later than" dates for regulatory approvals, environmental permits, ROW acquisition, engineering and design, material procurement, construction, commissioning, energization, and final in-service date.

All respondents have identified potential schedule risk and planned mitigation measures, including utilizing schedule float.

Construction

All Respondents identified their detailed Construction Management Processes, including deploying highly qualified and experienced contractors and staff. All plans include detailed safety protocols applicable to all participants in the process.

Commissioning Process

All Respondents have adequately described their commissioning plans, including detailed descriptions of items to be considered, coordination plans with Wolf Creek and Blackberry substation owners, and interconnection agreements.

Timeframe to Construct/Milestones

All Respondents provided adequate descriptions of their proposed "time to construct" dates in their "Project Development Schedule."

Milestone dates and potential risks also provided.

Experience/Track Record

All Respondents have demonstrated experience and strong track records in successfully constructing significant EHV transmission projects in the last five years.

The following section presents the final scoring for each proposal for each category/sub-category in the Project Management section. The maximum points possible, the points awarded, and the percent of the maximum points awarded is shown for each category/sub-category.

Proposals A&B[1]

Environmental - 30/27/90%

Route Selection - 20/18/90%
Regulatory - 5/4/80%
Support Staff - 5/5/100%

Proposals A/B were both rated "Better" for the Route Selection sub-category based on their description of their detailed route selection processes and how it had been used successfully for other projects.

The Regulatory sub-category was rated "Good" based on Respondent's familiarity with the various regulatory/permitting processes [redacted], which experience will assist in routing and environmental permitting.

Respondent indicated that they have retained or are planning to retain experienced contractors/consultants with first-hand knowledge and experience with the area expected to be traversed by the new line and plan to assign excellent staff resources to this portion of the Project, leading to a "*Best*" score of 100% for the Support Staff sub-category for these two proposals.

- Routing study firm >100 years experience
- Successfully performed routing studies in Kansas and Missouri.
- Environmental consultant one of the largest in the U.S. with significant experience in Kansas and Missouri.
- Plan to retain experienced contractors/firms to assist in routing and environmental permitting activities, including:
  - [redacted] (routing study firm) - successfully performed routing studies in Kansas and Missouri.
  - [redacted] (environmental counsel) - provided environmental permitting and legal support to implement 300+ miles of 345 kV transmission.
  - [redacted] - comprehensive, full-service approach to managing planning, permitting, and environmental compliance for transmission lines; significant experience in Kansas and Missouri.
- Approximately 2,900 square mile study area, detailed routing study; desktop selection analysis; detailed design and structure spotting; field visits; local knowledge; and direct consultation with regulatory agencies.
- Identified a geographically diverse set of route alternatives that take advantage of opportunities and avoid constraints to the extent possible; resulted in 19 unique routes. Routing team combined the strongest portions into 5 alternative routes for detailed evaluation.[2]

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[1] Proposals A and B are identical for the Project Management section.

[2] Respondent identified three (3) route alternatives, including the preferred route, [redacted]

[redacted]

- Parallels compatible lines and avoids conflicting infrastructure.
- Minimizes distance crossing mined lands; no airport impacts.
- Route avoids [redacted] location.
- Preferred route provides lowest risk of implementation; limited impacts to environment (e.g., bat habitats) and communities while being economical to construct and maintain.

[redacted]

- Kansas CPCN – must demonstrate Project promotes public convenience to use eminent domain, if needed; will not file CPCN application until project awarded.
- Detailed Public Outreach Plan; no public engagement until NTC received.
- Permitting plan developed using the local, state and federal experience of Respondent in coordination with permitting and environmental expertise of environmental consultant. Plan provides a comprehensive discussion of permits and authorizations required for the preferred route.
- Consulted with applicable permitting agencies to confirm the applicability of statutes and regulations to the Project scope and support permit applications.
- Will host three or more public open-house meetings to solicit comments/inputs from residents, landowners, public officials, and other interested parties; notice will be published in local newspapers and provided to property owners, county commissioners, and other relevant agencies and governmental officials.
- Will conduct additional reconnaissance surveys to evaluate the information received through public outreach; surveys, together with information from the public open house meetings, will be used to modify the preferred route.
- Will construct the final route with minor deviations allowed to accommodate directly affected landowners.

ROW - 30/27/90%

Acquisition - 20/17/85%
Regulatory - 5/5/100%
Support Staff - 5/5/100%

Proposals A/B are rated "Better" for ROW Acquisition, as proponent has extensive experience acquiring ROW [redacted] Proposals A/B are rated "Best" for both Regulatory and Support Staff as they are using qualified land agents and support staff for ROW acquisition.

- Experience acquiring ROW/land rights [redacted]
- Retained experienced land acquisition firm, appraisal consultant and surveying consultant with qualified ROW agents with Kansas and Missouri-specific experience.
- Detailed land valuation study to inform easement values for the Project area.
- Detailed study to determine ROW and land rights necessary to implement the Project; identified ownership of every parcel of land impacted by preferred route and prepared an easement acquisition budget by parcel for permanent easements.[3]

[3] Majority of land rights will be permanent easements.

- Establish ROW acquisition database; conduct land market study[4]; incentivize early easement execution; use above-average land value + early signing bonuses; and use eminent domain only if necessary.
- Obtained rights of entry to support pre-construction activities, environmental survey, regulatory permitting, and geotechnical investigations.
- Procurement of meaningful ROW ahead of public engagement processes and regulatory processes would not be consistent with best practices and could lead to confusion that could jeopardize the Project.
- ROW Manager will oversee activities of ROW acquisition firm [redacted] and provide necessary guidance; [redacted] will employ qualified ROW agents with Kansas and Missouri-specific experience that are trained on Project specifics and negotiation strategies.
- Will review and perform due diligence on all ROW agents; conduct training on scope of Project.
- Guiding principles for interactions with landowners: communications and information presented is to be factually correct and made in good faith; all communications and interactions must be respectful and fair, and all communications and interactions must respect the privacy of the landowner or other stakeholders.

Procurement and Engineering - 15/14/93%

Process - 10/9/90%
Support Staff - 5/5/100%

Proposals A/B are judged "Better" as they are planning to retain one of the largest EHV engineering, procurement, and construction contractors in the U.S.

[redacted]

Support Staff is rated "Best" as proponent plans to assign the most qualified staff to support this project.

- Will retain several experienced contractors/firms to assist in engineering, procurement and materials management including:
  - [redacted] (construction contractor) - one of the largest EHV transmission construction contractors in the U.S.; [redacted]
  - [redacted] (detailed engineering) - top T&D design firm with significant years of design and engineering experience; [redacted]
  - [redacted] (geotechnical investigations), a multi-disciplinary firm specializing in environmental, facilities, geotechnical, and materials services; [redacted]
- Already completed comprehensive studies on conductor selection, geotechnical issues, structures/foundations, and soil corrosivity.
- Plan to use LIDAR survey to confirm and update structure loading and framing drawings and provide results to suppliers.
- Will directly purchase all major materials from pre-qualified suppliers based on recent

[4] A land valuation study has been completed to inform easement values for the Project area.

performance, ability to meet schedules and design specs without defects.

- Will use a single supplier for insulator assemblies/hardware to ensure proper fit.
- Non-conformance reports will be provided to suppliers and confirm corrective actions.
- Guaranteed delivery dates on all materials.
- [redacted]
- Transmission line engineers, procurement QA/QC manager, corporate counsel and other internal management teams will provide support.
- The Engineering and Procurement Director has the primary responsibility for managing engineering and procurement activities in coordination with the Project Director.
- Completed a comprehensive conductor selection study, electrical studies, geotechnical studies, structure and foundation studies, and soil corrosivity study.
- Structure loading and framing drawings will be updated based on the final route and LiDAR survey, and provided to suppliers along with conductor specs and transmission line hardware as part of the proposal package used in the material procurement process.
- Once design is finalized, the Engineering and Procurement team will prepare a detailed construction package stipulating how the Project is to be constructed.
- Will directly purchase major materials including the structures, conductor, optical ground wire, and insulators and hardware; [redacted] will procure other materials necessary for construction, including guy wire, rock anchors, gravel, concrete, culverts, fencing, gates, matting, etc.
- All designs provided by suppliers will be reviewed and approved by Respondent and [redacted].
- Pre-qualified suppliers based upon recent performance on similar projects including demonstrating an ability to meet design specifications and deliver materials on schedule without defect; also recently audited the material fabrication and delivery process for all of these suppliers; comfortable with their ability to perform to their contract terms and conditions.
- Insulator assemblies and associated hardware will be purchased from one supplier to ensure assemblies are well designed and fit properly; OPGW assemblies and associated hardware will also be purchased from one supplier.
- Each proposal package will be for the design, fabrication, testing, quality control, packaging, shipping and delivery of the material in accordance with detailed engineering and design requirements specified, and include proposal instructions, proposal forms, a summary of work, technical specifications, and a form of agreement.
- Will conduct a comprehensive evaluation of the proposals to understand each supplier's proposed terms and conditions, design, schedule and price; follow up meetings and discussions conducted with suppliers to ensure understanding of their proposals.
- Contracts awarded to suppliers that provide an acceptable design with certainty in the ability to meet schedule at the lowest overall cost. All procurement contracts reviewed by legal counsel and approved by the Project Director prior to execution.
- All materials procured by [redacted] will meet the detailed specifications and quality requirements for the Project. [redacted] will have access to its vast network of suppliers for these purchases. Prior to selecting suppliers, [redacted] will consult with the Respondent regarding suppliers' ability to meet specifications.
- Oversight will occur through inspections, testing, and witnessing the fabrication process along with progress reporting to ensure production and deliveries meet requirements.

- Inspectors will ensure use of certified welders, and confirm manufacturing of a high quality structure.
- Non-Conformance Reports will be issued to the supplier when an item or condition is not in compliance with designated requirements, instructions, or specifications. Will confirm corrective actions have taken place prior to the scheduling of any deliveries of the material.
- Any modification to the contract price, schedule or specifications must be authorized by the Project Director through a Change Order using the issue management process.
- Construction execution plan includes details related to material management, delivery and storage to support construction.
- Project Management Plan will include methods to limit risk, manage schedule, and control costs.
- Risk mitigation strategies may include executing procurement contracts ahead of schedule, hedging commodity prices, purchasing raw materials, reserving shop space, or taking early delivery of materials.
- Supplier contracts detail specific quality assurance provisions with a quality control system that must be approved by the Respondent. All tests and inspections will be performed and accepted by the Respondent before any material is shipped. Respondent can reject any material that is defective or nonconforming with the Project specifications and return it to the supplier for repair, replacement or a credit back with all costs and expenses to the supplier's account.
- Supplier is required to monitor, report, forecast and control the progress of fabrication and delivery in accordance with an agreed upon schedule that will include guaranteed delivery dates.
- [redacted] will manage the delivery, inspection, offloading and storage of materials to support construction activities, and establish [redacted] material yards in the vicinity of the Project prior to commencement of construction. Majority of materials will be delivered, inspected and stockpiled in the material yards before foundation installation begins.

Project Development Schedule/Scope - 25/20/80%

Project Scope/Specifications - 15/12/80%
Potential Risks/Mitigation Plans - 5/4/80%
Regulatory Approval Process/Mitigation Plans - 5/4/80%

Proposals A/B are judged "Good" for all sub-categories of Project Development Schedule/Scope based on their efforts to develop a thorough understanding of the project-specific requirements and identification of associated risks and mitigation plans.

- Significant effort expended to develop thorough understanding of Project specific construction requirements, e.g., clearing, access roads, site grading, foundations and anchors, and wire stringing.
- Project Risk Register includes [redacted] potential risk and mitigation plans, including final route evaluation, regulatory permitting, permit conditions/requirements, ROW/land acquisition, material procurement, construction, Wolf Creek access, commissioning and energization.
- Included table of "No Later Than" dates.
- [redacted]

[redacted]

- Respondent responsible for all routing, design, permitting, financing, procurement, construction, and any other activity necessary to cause the Project to be ready for energization by the needed date.
- Parent company will provide operations and maintenance services for the Project.
- Detailed implementation schedules included for all aspects of the Project.
- [redacted].
- Scheduled float:
  - Route Evaluation [redacted]
  - Regulatory and Environmental Permitting [redacted]
  - ROW and Land Acquisition [redacted]
  - Material Procurement [redacted]
  - Construction, Commissioning and Energization [redacted]

[redacted]

- Proposal packages will be updated to reflect final design and released to vendors in the [redacted] Contracts for materials will be executed by the middle of [redacted] to provide price assurance, reserve facility capacity, and to ensure timely fabrication and delivery to support construction activities beginning in the [redacted].
- Detailed weather analysis conducted to assess the likely number of construction days that may be impacted by adverse weather conditions; schedule allows for [redacted] due to weather. [redacted] has more than [redacted] of schedule float to absorb additional weather days and could add shifts during planned days off.
- Construction will commence with tree clearing and construction of access roads in the [redacted] Installation of foundations will begin at the start of [redacted] and be followed by structure installation beginning in [redacted] Wire stringing will occur in [redacted] through [redacted] in coordination with outages for line crossings. [redacted]

- Critical Path includes: Kansas and Missouri state commission approvals, trail crossings, permits prior to construction, clearing and access during construction, commissioning and energization following construction.
- Will continue to monitor and update the Critical Path throughout implementation of the Project.

Construction - 45/40/89%

Process and Plan - 25/22/88%

Project Manager and Staff - 20/18/90%

Proposals A/B are judged "Better" for both Process and Plan and Project Manager and Staff as a result of their experience constructing projects of similar scope.

- Successfully completed [redacted] of 345 kV transmission in the last 10 years.
- Experienced contractors for construction, foundations, clearing/access, engineer of record.

All contractors retain full-time safety personnel:

- [redacted] (construction contractor)
- [redacted] (foundation subcontractor)
- [redacted] (potential clearing and access subcontractor)
- [redacted] (potential clearing and access subcontractor)
- [redacted] (engineer of record)

- Respondent has advanced implementation of the Project and expended significant resources to confirm it can be constructed on both schedule and budget: routing study; consultation with regulatory/permitting agencies; land rights needed and acquisition plan; detailed engineering studies; execution plans for procurement, construction and commissioning; detailed implementation schedule and Risk Register.
- Two dedicated inspectors and a construction manager in the field during construction; will regularly observe, inspect and report on construction progress and quality; ensure compliance with environmental permits, ROW agreements, and safety practices; construction contractor will maintain quality control reports that will be prepared and submitted to Respondent's inspectors for review.
- Construction contractor will establish a local field office that will be self-sufficient and act as the hub for Project team members with construction management personnel based in the office.

[redacted]

- Construction Contractor to establish Inventory Management Program to track shipment of materials, location and delivery to [redacted] material yards spaced along route.
- Identified all ROW and land rights necessary to implement the Project with a detailed acquisition plan.
- Detailed engineering including electrical studies, PLS-CADD models, detailed drawings and diagrams, detailed specifications, and foundation details; Project-specific execution plans for procurement, construction and commissioning; and Detailed implementation schedule and risk register.
- No unique constructability risk; construction plan informed by site visits; design and construction plans incorporate those risks.
- Detailed construction plan assures SPP that Respondent has taken Project specific details into consideration and can execute its plan.
- Project Director to communicate pertinent requirements to the construction contractor and the local field office.
- Will communicate permit requirements, landowner requirements, county-approved haul routes, etc. to construction contractor prior to commencement of construction; documented in writing and discussed at pre-construction planning meetings.
- Parties will establish clear lines of communication for the construction process and make sure the Project goals and expectations are clearly understood.
- Construction contractor will establish a local field office that will be self-sufficient and act as the hub for Project team members with construction contractor construction management personnel based in the office.
- QA/QC manager, construction manager, and field inspectors will have the primary responsibility of ensuring quality during the construction process; construction manager and field inspectors stationed in the field during construction and able to immediately address any quality issues to avoid major impacts.

[redacted]

- Construction contractor to submit detailed work plans and Q-control inspection reports to Project Director
- Project Director and Construction Contractor to establish access plan.
- Construction Contractor to establish Inventory Management Program to track shipment of materials, location and delivery.
- [redacted] Wire installation plan - [redacted]
- Final Inspection: Project released to Project Director after conductor and OPGW installed; Project Director to conduct final inspection.
- Final restoration process will begin once the Respondent completes its final inspection and construction contractor has corrected any discrepancies.
- Safety and Health Director will have primary responsibility for ensuring that Respondent implements the Project safely with support from the Project Director.
- Safety Training Program - require all contractors to submit safety plans
- Construction Contractor General Foreman responsible for all safety tasks.

Commissioning Process - 10/9/90%

Proposals A/B are judged "Better" for the adequate description of their commissioning plans and process, [redacted]

- Project Director to develop energization procedures with substation owners and enter into interconnection agreements.
- The Construction Director will have the primary responsibility for managing the commissioning activities in coordination with the Project Director.
- [redacted] Will coordinate outage schedules based on availability of outages at Wolf Creek and Blackberry; [redacted]
- Post energization inspection to confirm Project as-built including LIDAR survey.
- Prior to energization, Respondent and construction contractor will drive the length of the line to verify the phases are correctly aligned to synchronize with each substation and all construction grounds and safety devices have been removed.

Timeframe to Construct/Milestones - 20/20/100%

Proposals A/B are judged "Best" for Timeframe to Construct/Milestones as they have included substantial float in all phases of the project but still plan to complete all phases of work [redacted]

Also plan to consult with affected parties on the benefits of early energization.

- Respondent has advanced the Project as far as practicable without a Notification to Construct (NTC); upon receiving NTC, Respondent will immediately resume executing its detailed Project Implementation Plan, Construction Schedule, and Risk Register.

- Commencement of construction contingent on route approval from Kansas Corporation Commission (KCC) and Missouri Public Service Commission (PSC) followed by rights of entry onto private lands to complete environmental and geotechnical surveys.
- Physical construction to begin [redacted]
- If not have all land rights, can start construction where rights have been obtained.

[redacted]

- Foundation installation, structure assembly, stringing begin near Wolf Creek and move toward Blackberry.
- No requirement for simultaneous outages of multiple lines.
- Table of anticipated and "no later than" dates included.

Experience/Track Record - 25/25/100%

Proposals A/B are judged "Best" for their experience in successfully completing transmission projects of similar scope.

Proposals A/B also will leverage the experience of proponent's parent organization in delivering projects [redacted]

[redacted]

- Contractors have Kansas and Missouri based staff or experience.
- Construction Contractor has recent experience in Kansas and Missouri [redacted]

Other

- Parent company and Construction Contractor: [redacted]
- No additional costs or regulatory requirements related to Wolf Creek substation

Proposal C

Environmental - 30/24/80%

Route Selection - 20/15/75%
Regulatory - 5/4/80%
Support Staff - 5/5/100%

Proposal C was judged "Good" for Route Selection and Regulatory, as the Respondent indicated it had developed [redacted] new EHV transmission projects [redacted] one of which was not completed on schedule.

Proposal C was judged "Best" for Support Staff as proponent plans to assign experienced contractors and high level support staff to the project.

- Respondent has significant experience working collaboratively with federal, state, local and other regulatory bodies, especially.
- Respondent has engaged [redacted] a legal and regulatory law firm with offices in Kansas City with significant number of years of siting and regulatory experience in Kansas and Missouri.
- Retained [redacted] to assist with engineering, environmental, and routing; experienced transmission line design and permitting firm in both Kansas and Missouri.
- Environmental permitting strategy minimizes the number of permits required.
- Detailed Environmental Permitting Timeline included.
- Longest lead-time environmental approvals are the voluntary, informal coordination with several agencies; upon receipt of Notice to Proceed, voluntary, informal coordination with U.S. Fish and Wildlife Service (USFWS), KDWPT, Missouri Dept. of Natural Resources (DNR), Missouri Dept. of Conservation (MDC) etc. will begin.
- Very thorough and detailed route selection process.
- Captured and used High Precision LiDAR data on the Project to analyze superior topographic data and high-resolution aerial imagery.
- Key considerations for the evaluation and selection of the Preferred Route:
  [redacted]
- Reviewed all 345 kV route proposals submitted to KCC in the past 13 years – including contested routes and challenges from KCC Staff on routing decisions; Respondent and [redacted]
- [redacted] different end-to-end possible routes; narrowed down using structured route evaluation process to a short list of [redacted] potential routes, and then to the proposed route.
- Proposed route [redacted] follows a direct, shortest distance path while avoiding all known risks.
- Followed KCC and MPSC guidelines for a direct, shortest distance siting approach while avoiding key environmental, regulatory, and cultural sensitivities.
- Route designed to minimize wetland impacts, reclaimed strip mines, oil/gas well fields, State and Federal forests, FAA regulation impacts, impact on communities, habitats for protected species, etc.

- Five species (Gray Bat, Indiana Bat, Northern Long-Eared Bat, Eastern Spotted Skunk, and Broadhead Skink) could have potential habitat that occurs within the counties crossed by the Project route and be affected by construction of an overhead electric transmission line.
- Team visited, drove, and visually assessed key aspects of the Project [redacted]
- Minimize impacts through a combination of physical mitigation and avoidance efforts.
- Detailed table of Local Site-Specific Environmental Risk, Mitigating Measures, Timeline, and Status Summary.
- Based on studies, LiDAR data, site visits, and intensive collaboration with engineering and environmental teams, Respondent has imposed several constraints that greatly reduce the complexity, cost, and timeline of wetland and stream permitting:

[redacted]

- All environmental permits for Federal, state and local jurisdictions, even if not required for the Selected Route, were built into the schedule.
- Identified the major environmental issues that could have an impact, what specific criteria would be used for determining Project impact, and the regulatory body or permitting agency involved in the approval of resolution (permits).
- Detailed timeline for Environmental Permitting activities included in the Project schedule.
- Project team conducted data collection, field reconnaissance and regulatory research and quantitative route comparisons to complete the initial route evaluation.
- In addition to streamlining permitting, avoidance of sensitive environmental areas also helps decrease the risk of noncompliance during construction.
- Respondent will have a Field Operations team that will be supported by the environmental team to manage the Project's ongoing environmental obligations.
- Environmental related risks have been fully identified; Respondent has prepared a Project Risk Matrix for those risks; managed from development through completion; collected in a Risk and Issues Log.

[redacted]

ROW - 30/24/80%

Acquisition - 20/15/75%
Regulatory - 5/4/80%
Support Staff - 5/5/100%

Proposal C was judged "Good" for ROW Acquisition and Regulatory. [redacted]

Proposal C's plan to assign experienced Support Staff to the project was judged "Best".

- Plan to use [redacted] of the parent company. [redacted]
- In process of securing site control at key locations along ROW, [redacted]
- Records of Landowner Contacts logged into a tracking table and updated daily. [redacted]
- Respondent and land acquisition contractor have developed a table of FAQs and Responses to use when talking with landowners.
- Will pay for crop damage and/or physical damages resulting from construction or maintenance activities.
- Proposal includes a table of ROW Acquisition risk and Proposed Mitigations.
- Acquisition of land rights based on principles that support and facilitate timely resolutions and fair settlements with directly affected landowners through negotiation of mutually acceptable agreements using a consistent compensation offering based on fair market value of lands.
- Eminent domain used as a last resort; process of gaining ability to exercise eminent domain will be initiated to allow an appropriate amount of time to gain regulatory approval.[redacted]
- Proposed width of the ROW [redacted] based on: structure type, number of structures, span distance, terrain, soil conditions, and may vary to accommodate topographic features, challenging crossing locations and provide flexibility in final structure placement.
- Land Acquisition Process:

[redacted]

  - Respondent responsible for overall Project undertaking; will provide input to landowner engagement strategy; Respondent legal counsel will review populated easement agreements and support adjustments if necessary.
  - Land Broker [redacted] will support Respondent by leading ROW acquisitions; responsible for development and execution of landowner engagement strategy; [redacted] land agents will form meaningful relationships with landowners and will lead discussions toward amicable settlement.
  - Individual landowners will liaise with Respondent and [redacted] throughout negotiations towards amicable settlements and through eminent domain pursuits, if necessary; expected that landowners will negotiate with Respondent in good faith.
- Team of [redacted] internal land agents located in Kansas and Missouri that have extensive experience in fossil, wind, solar, and transmission-related projects. Overseen by the Director of Land Acquisition.
- Committed to creating long-term relationships in the communities within which it works; follows its established process and code of conduct when engaging landowners.
- Will conduct public outreach with landowners along the proposed route, including public notifications of the project, open houses, opportunity to submit comments, and meeting with local officials.
- For each contact made with landowners, a summary of the interaction will be recorded.
- Land Manager provides strategic guidance to Land Agents to support furtherance of negotiations; check Records of Contacts (ROCs) to ensure they are scrubbed of any sensitive information, and that messaging is clear and concise. ROCs are logged in a tracking table that is updated daily.
- To effectively manage stakeholder concerns, the team uses an internal ticketing system to track requests.
- Respondent and [redacted] have developed messaging to answer questions or concerns preemptively and consistently. (Table of FAQs and Responses)
- Seek Right of Entry Agreements from landowners along the route to permit access for various studies and investigations, including geotechnical studies and environmental due diligence.
- Land Agreement Process includes description of steps and deliverables.
- Fair compensation for landowners will be determined by a third-party appraisal firm and licensed by the Missouri Real Estate Appraisers Commission and the Kansas Real Estate Appraisal Board.
- Table of Specific Option Cost Summary Items and Payment Terms.
- Table of ROW Acquisition risk and Proposed Mitigation.
- Detailed description of [redacted] experience in land acquisition.

Procurement - 15/14/93%

Process - 10/9/90%

Support Staff - 5/5/100%

Proposal C is judged "Better" for Process and "Best" for Support Staff, as it will use an application process to identify and pre-approve "preferred vendors," Proponent has also secured space in priority vendors' manufacturing queues.

Parent company of the proponent has long-standing development and supply alliances with vendors.

- Strong procurement process and team: manages vendor relationships and leverages economies of scale to secure most favorable terms.
- All vendors for the Project have undergone rigorous review under Respondent's application process to become "preferred vendors" and have been pre-approved.
- Secured adequate space and priority in the vendors' manufacturing processes and queues, to ensure timely delivery of main materials.
- Parent company has a long-standing development and supply alliances with vendors; Respondent has entered into project specific agreements to purchase strategic major materials for Wolf Creek-Blackberry Project from these industry leading suppliers:
    - Engineering and design services - [redacted]
    - Transmission pole manufacturing - [redacted]
    - Conductor supply - [redacted]
    - Optical ground wire - [redacted]
    - Construction labor, equipment and BOP materials - [redacted]
    - Supplemental local operations and maintenance support - [redacted]
- All long-lead equipment and materials scheduled with lead times based on Respondent's extensive knowledge of market conditions and from its strong working relationships with key suppliers.
- Project schedule adjusted to allow additional time for delays in material deliveries that could result from various causes.
- [redacted] - dashboard of performance indicators for planned versus actual performance of all suppliers.
- [redacted] - supports the Project Management team in analyzing current versus planned activity and working with suppliers to ensure planned deliverables are met.
- [redacted]
- Third-party services and materials procured through [redacted]
- Respondent's engineering team will work with its consultant, [redacted] to provide detailed design services for the Project.
- All major materials will be produced in the U.S., therefore eliminating any non-domestic sourcing risk for the Project.

Project Development Schedule/Scope - 25/22/88%

Project Scope/Specifications - 15/13/87%

Potential Risks/Mitigation Plans - 5/5/100%

Regulatory Approval Process/Mitigation Plans - 5/4/80%

Proposal C was judged "Better" for Project Scope/Specifications and "Best" for Potential Risks/Mitigation Plans as a result of their detailed approach to identifying risks and mitigation plans.

Proposal C also offers [redacted]

- Respondent able to offer [redacted]

[redacted]

- Confident in ability to meet [redacted]
- Immediately upon award of the Project, Respondent will begin executing on critical path items including preparing Certificate of Convenience and Necessity (CCN) and line siting applications, acquiring landowner agreements and finalizing the design.
- Float has been allocated to the work schedule to address risk that may occur:
  [redacted]
- Project Schedule contains all project activities, including but not limited to: route and site evaluation, regulatory permitting, land acquisition, engineering and design, land surveying, material procurement, construction, and commissioning/energization activities.
- The schedule uses critical path methodology with the appropriate predecessor-successor linkages established; Project schedule is monitored for activities that could delay execution.
- [redacted] Following items on the critical path relative to project [redacted]
- Project manager is notified of any linkage conflicts that could delay and constantly evaluates the schedule to adjust as needed.
- [redacted] Project's critical path includes [redacted]
- Project Risk Matrix to identify, prioritize and mitigate potential risk.
- [redacted] Detailed approach to risk identification and mitigation based on the well-known [redacted]
- Flexibility in project schedule to accommodate Wolf Creek's 18-month refueling outage schedule.
- Respondent, along with affiliates and third-party support staff, offers a turn-key model for developing, constructing, and operating the Project.
- Detailed project schedule with [redacted]
- Project incorporated into Respondent's Work Breakdown Structure (WBS) accounting system to enable detailed tracking of project budget and schedule.
- [redacted] makes project data accessible to all internal and external team members.
- Project Schedule contains all project activities, including but not limited to: route and site evaluation, regulatory permitting, land acquisition, engineering and design, land surveying, material procurement, construction, and commissioning/energization activities.
- High level Gantt Chart of the Project Schedule provided.
- Upon award of the Project, Respondent will secure a Total Liability Insurance Policy related to the overall Project; during construction and operations, the Project will be fully self-insured consistent with industry practice.
- Project will require regulatory approvals from the KCC, the MPSC, and various counties in Kansas and Missouri. [redacted].

Construction - 45/35/78%

Process and Plan - 25/20/80%

Project Manager and Staff - 20/15/75%

Proposal C was judged "Good" Proponent cited construction of large-scale transmission lines as a core competency. Respondent's parent company has a great deal of experience developing transmission [redacted] Proposal C listed five competitive upgrade transmission projects from [redacted], 80% of which were completed on schedule.

- Construction of large-scale transmission lines is a core competency of Respondent through its experienced team and affiliates, with proven capabilities and depth of experience in constructing and managing high voltage transmission line projects of similar size, type, and technology.
- Project Execution Plan (PEP) best way to manage project execution and risk; developed early in project cycle.
- Engage all project teams and development teams early in the project management process to create strong working relationships and effective internal communication.
- External communication with major stakeholders including landowners, county officials, and owners of assets crossing the route is essential to meet Project objectives.
- Will coordinate several design review and constructability review meetings with Project Manager, transmission line design engineer and line construction contractor, plus Respondent's construction management team: Project Manager, Engineering Leader and Project Engineering Lead.
- Utilize established project controls methodology; provides methods and tools for budget control, scheduling, tracking, trending, and reporting of work in progress for the engineering, procurement and construction activities.
- Construction management and inspection team will conduct preparatory meetings with [redacted] prior to initiation of major components of work.
- During construction, the plan will be monitored using the: [redacted]
- Schedule, budget, and Risk Register updated based on current information; results of updates used to adjust project plan and potentially compensate for deviations; changes are communicated to all team members affected by the changes.
- Use existing roads to reduce costs of building separate access roads that duplicate the path of existing roads.
- Access roads planned to be built in conjunction with clearing activity; building access roads once while using them for all activities along the ROW.
- Access road file contains:

  [redacted]
- Mobilization of equipment and manpower will begin as needed to meet anticipated schedule to start conductor installation on the project.
- [redacted] laydown yards.

[redacted]

- Construction program prepares for and actively mitigates risk that could delay construction or increase costs.

- Risk Register identifies risk, potential impacts, and the mitigation; float in schedule available as needed.
- Project Manager relies on the Project Controls department for budget control, scheduling, tracking, trending, and reporting of work in progress.
- [redacted] used to ensure Project parties are aligned on Project requirements, reporting progress, daily reporting, cost change deviations, and project turnover documentation to ensure seamless execution.
- Will work with [redacted] to organize into [redacted] mostly independent operating crews; construction sequence will begin at [redacted] followed by the construction of [redacted]
- When received at the delivery point, items will be checked for condition and correct quantity; shipping records will be kept and reported as appropriate.
- Expect to retain [redacted], a leading regional structural engineering firm, to perform a detailed analysis of the bridges along the planned access route.
- ROW clearing will follow a planned, logical sequence of events and start as soon as easements, permits and operating rights have been acquired.
- By using the same foreman and crew, efficiency and consistency is achieved throughout the framing process.
- Detailed plan for conductor stringing.
- Construction leaders/managers required to perform construction inspections using [redacted] - process verifies that facilities are constructed as designed and that all compliance documentation is provided by the appropriate construction or engineering contractor.
- "Contractor Safety Requirements Policy" provided to all contractors/subcontractors.
- Respondent's construction team 19-20 years of experience [redacted] 14-30 years of experience.
- Respondent's team will coordinate with the Wolf Creek Switchyard Coordinator for safety procedures, security access, scheduling, and related guidance.
- Transmission interconnection and substation work will be scheduled in windows outside of refueling to avoid conflicts with refueling activities.
- Respondent's parent and affiliates have extensive experience leading, and managing interconnections between nuclear facilities and transmission owners.
- Respondent's Engineering and Construction leadership will work with [redacted] to develop and provide Project-specific QA/QC plans based on the established QA/QC processes used by Respondent and [redacted] for every construction project.
- Construction plan broken down into [redacted] to complete structure framing and setting, conductor and OPGW installation.
- Alliance with [redacted] to expand parent company's construction capabilities and reduce project risk.
- Constructability reviews conducted in conjunction with environmental and engineering reviews reduces schedule and cost risk.

Commissioning Process - 10/10/100%

Proposal C was judged "Best" for their planned Commissioning Process.

Commissioning Manager for Proposal C has over [redacted] years of experience commissioning projects including specific experience with substations associated with nuclear plants.

- Commissioning Manager has over [redacted] years of experience; responsible to ensure line and substation assets are tested and commissioned in accordance with interconnection agreements negotiated with each substation owner.
- Goal of commissioning for the Project is to design it to occur in the shortest amount of time, no disruptions to electrical service and eliminate the need for future outages.
- Interconnection agreements for the Blackberry and Wolf Creek substations expected to define coordination, system and protection testing, scheduling of coordination meetings, phasing, fiber testing, outages and final connection of the new 345 kV transmission line.
- Number of system protection, control and monitoring components will be established in coordination with affected parties during interconnection requirements discussions during detailed design.
- Construction is expected to require crossing of the Wolf Creek to La Cygne 345 kV Line outside of the Wolf Creek facility, which will require coordination with Evergy, La Cygne Substation and Wolf Creek Generating station.[11]
- Energization Plan will be used to energize the Project; switching orders will be prepared consistent with SPP and AECI requirements; activities to energize the line, after connections have been made, are completed in a coordinated manner with all parties at each end of the line.
- Will use a visual confirmation after the line is completed, in addition to monitoring the completed sections of the line as new segments are built; confirmation will include a complete flyover of the Project as well as on-ground siting for the entire length of the line.
- Will submit an interconnection request to AECI, who will study the Request to assess compliance with NERC Standard FAC-001 R3/R4.
- AECI will determine if the Interconnection Request has the potential to impact any Third-Party Transmission Owner Facilities.
- Respondent and its affiliates have [redacted]; record of successful interconnection processes combined with Respondent's nuclear experience significantly reduces the risk associated with achieving a timely interconnection agreement at Wolf Creek.

[11] Wolf Creek to La Cygne line is a part of the NRC licensing for the Wolf Creek plant, which will require additional coordination and related agreements with Wolf Creek Generating Station to pull conductor over this 345 kV line.

Timeframe to Construct/Milestones - 20/18/90%

Proposal C Timeframe to Construct/Milestones was judged "Better" due to its built-in flexibility and [redacted] days of float for construction and commissioning activities. Additional [redacted] days of float makes the proponent confident in its ability to deliver the project [redacted]

- Project schedule with built-in flexibility and [redacted] for construction and commissioning activities to ensure the delivery of the project by the proposed in-service date.
- Project constructed in [redacted] to shorten the overall project schedule and reduce the likelihood of any [redacted] adversely impacting critical path.
- Key precursor activities to be completed prior to transmission line construction are engineering, ROW procurement and regulatory and environmental permits.
- Additional [redacted], in addition to the [redacted], makes Respondent confident in the proposed time frame to construct which delivers the project [redacted]
- Ample time in schedule to allow for the completion of these activities including: [redacted]
- Timetable covers start/end dates for:
  - ROW Prep and Clearing
  - Transmission Construction [redacted]
  - ROW Clean-up
- Primary Schedule risk/Mitigation:
  - Materials Delivery [redacted]
  - Weather – Winter/High Winds/Thunderstorms/Tornadoes [redacted]
  - Delay in obtaining Transmission Operator agreements impacting construction [redacted]
  - Material theft or vandalism of construction site [redacted]

Experience/Track Record - 25/22/88%

Proposal C was judged "Better" as it will operate under a shared services agreement with its parent company in which the proponent can draw on the entire range of resources of its parent and affiliated companies.

- Respondent will draw on the entire range of resources of its parent and affiliated companies to ensure successful delivery of the Wolf Creek-Blackberry project.
  - Engineering and Construction - [redacted]
  - Integrated Supply Chain [redacted]
  - Environmental Services - [redacted] minimize environmental impacts and reduce permitting and project schedule risk.
  - Power Delivery - [redacted] team members.
  - Regulatory and Legal [redacted] attorneys and staff specializing in Federal, state and local energy sector regulatory proceedings.

- Operate under a "support services" model which enables it to draw on resources and expertise across the entire family of companies.
- Parent company's subsidiaries have built [redacted]
- By the end of 2021 [redacted]
- Extensive nuclear experience; [redacted] experience owning, operating and maintaining nuclear facilities.

[redacted]

Other

[redacted]

- Plan to use [redacted] minimal visual impact, blend into environment, structural reliability, less maintenance, and longer life [redacted].
- Respondent secured exclusive landowner options for [redacted]
- Pandemic Response Plan - Focused on developing and implementing safety programs to navigate COVID pandemic.
- Engineering Design, Construction, and Procurement teams are under the same leadership structure; close coordination among these three functions for every project.

[redacted]

- Parent company has a strong culture of innovation and continuous improvement - [redacted]

[redacted] Has entered into a definitive agreement to acquire several related companies that currently own [redacted]

Proposals D&E [12]

Environmental - 30/24/80%

Route Selection - 20/15/75%
Regulatory - 5/4/80%
Support Staff - 5/5/100%

Proposals D/E were judged "Good" for Route Selection and Regulatory. Proponent has reached out to prospective landowners in advance of the contract being awarded, which can lead to confusion if another proponent is awarded the contract.

Proposals D/E was judged "Best" in Support Staff as the proponent has assigned a team of experienced subject matter experts with a proven record working in Kansas and Missouri.

- Siting, environmental assessment, permitting, and construction monitoring will be completed by [redacted] provides professional design and consulting services in planning, engineering, environmental, surveying, and project management.
- Team of subject matter experts with extensive experience working on projects of similar size and complexity throughout the United States and a proven track record [redacted]
- Proactively reaches out to regulators, legislators, landowners, and the public to vet preliminary study areas; uses a phased approach to eliminate those sites that are most impactful to focus on a final route that meets both internal and external criteria.
- Successfully used this collaborative process over the past several years to obtain [redacted]
- Will contract with the parent company to leverage internal resources and contract with key sub-contractors to complete site selection tasks.
- Site selection team will include subject matter experts from a variety of disciplines including planning, design, construction, real estate, environmental, and public communications.
- Respondent already completed a Siting Study to identify the Proposed Route for the Project; defined a 2,196 square mile Study Area for further evaluation.
- Established a segment network with [redacted]
- Field reconnaissance trip to review the Proposed Route via helicopter and ground-based surveys was completed to review constructability and access considerations.
- Proposed route was selected because it minimized overall potential impacts, took advantage of routing opportunities, minimized impacts to biological resources and avoided cultural resources, while maximizing opportunities to align with existing transmission line corridors and rights-of-way.

[12] Proposals D and E are identical for the Project Management category. [redacted]

- Considered critical habitat and extensive floodplains [redacted] existing and proposed wind/solar energy developments, reclaimed surface mines widespread in the vicinity of [redacted] significant above- and below-ground oil/gas facilities, and several municipalities with high density residential and commercial development.
- Proposed route has a lower number of 303d Impaired waterways, KDWPT-identified "remnant prairies" and known contaminated sites than other routes evaluated in the Siting Study.
- Proposed route had fewer heavy angle turns than other alternatives, representing a reasonable tradeoff between route length and minimized impact to the natural or human environment; no residences in the ROW, few nearby residences and other places of congregation. [redacted]
- Looked for opportunities to site along roadsides and along section or quarter section boundaries to minimize impacts to farming operations.
- Respondent believes proposed route can be supported through the regulatory process and will present a reasonable approach to the local community.
- Proposed route will be thoroughly evaluated as part of the routing process post-award, incorporating input from local, state, and federal stakeholders.
- When the Project is awarded, Respondent will consult with potentially affected agencies, collect public comments during a round of open houses, and gather additional non-public sources for information to refine the proposed route or select a new route if necessary.
- Local stakeholder engagement plan is part of routing and land acquisition plans; will consist of one-on-one meetings with local elected officials, and an open house for all affected landowners. Goal is to establish strong working relationships with local leaders and property owners.
- Respondent identified several major environmental constraints and critical issues in the Study Area, which were avoided to the extent possible during development of the Proposed Route.

ROW - 30/27/90%

Acquisition - 20/17/85%
Regulatory - 5/5/100%
Support Staff - 5/100%

Proposals D/E were judged "Better" for Acquisition and "Best" for Regulatory and Support Staff due to the extensive land acquisition plan and assigned resources.

Proponent for Proposals D/E has a Route Development Agreement with its parent company, [redacted]

- Extensive Land Acquisition Plan; goes into detail concerning internal and external resources devoted to researching, acquiring, and managing real property assets, which include fee owned properties, transmission and distribution rights-of-way and other miscellaneous property rights. [redacted]

[redacted]

- The [redacted] works very closely with parent's Planning, Stakeholder Relations, Engineering, Environmental Services, Legal, Governmental Affairs and Communications departments to either verify existing rights-of-way or acquire new rights-of-way and real property interests.
- Respondent has strong preference for acquiring property rights through fair, good faith negotiations with affected property owners; [redacted] has considerable experience working with state regulatory commissions and local courts to ensure all necessary property rights are acquired in a fair, equitable and timely manner to keep projects on schedule.
- Worked with [redacted] to develop a detailed land acquisition plan, including proposed schedule and estimated real estate costs.

[redacted]

- Will either submit one filing as co-applicants, or separate filings with a request for the KCC to consolidate to align the regulatory approval timeframes.

[redacted]

- [redacted] will provide right of way acquisition services and support for landowner negotiations; involved in successfully planning, managing and executing over 46,500 miles of acquisition and negotiating over 30,000 acres of fee purchase and leaseholds.
- Will implement a local stakeholder engagement plan as part the routing and land acquisition plans for this Project; one-on-one meetings with local elected officials, followed by an open house for all affected landowners.
- [redacted] giving Respondent confidence it will be able to secure the remaining rights in this area successfully.

[redacted]

- Has secured all the parcels [redacted] necessary to construct the Project.

[redacted]

- ROW will be required from approximately [redacted] parcels owned by [redacted] unique landowners; primarily agricultural, with no impacted parcels classified as irrigated [redacted] residential properties are potentially impacted.
- [redacted] parcels held by corporations, companies, or partnerships; another [redacted] properties held by out of state private owners; [redacted] of the properties held in trusts. These properties will be targeted early in the process to minimize schedule impacts.

- Engaged [redacted], a local Appraiser that is licensed in Kansas and is knowledgeable of Kansas statutes, based on their experience as expert witnesses and in providing litigation support on similar projects.
- [redacted] to initiate field work and secure transmission easement documents from landowners.
- Will host three open house events to expedite the initial rollout of the Project prior to its filings with the KCC; upon KCC approval, Respondent will hold an additional three meetings for directly impacted landowners to establish relationships and attempt to obtain survey permissions from landowners in attendance.
- Acquisition strategy will be to acquire easements utilizing GIS sketch exhibits; once survey completes final exhibits, land agents will return to landowners for an Amended Easement agreement; approach will allow survey and acquisition to proceed in parallel so that land agents can maximize use of their time and help to ensure there are no schedule delays.
- Land agents will notify landowners prior to the start of construction activity and act as liaison between the construction group and landowners and their tenants; will also assist in the acquisition of any contractor required laydown areas, additional workspace or other interests that may be desired by the construction group.
- Will secure all non-environmental permits for road and utility crossings; State Highway crossings will require a crossing permit issued by Kansas Dept. of Transportation.
- Use of eminent domain rights considered as a last resort.

Procurement and Engineering - 15/15/100%

Process - 10/10/100%
Support Staff - 5/5/100%

Proposals D/E are judged "Best" for Process and Support Staff [redacted]

All materials have already been competitively bid and discussed material manufacturing and delivery timelines to prevent risk of delays.

- [redacted] will deliver project management, engineering, procurement, and construction services through its affiliates and other strategic partners and subcontractors.
- [redacted] will provide turnkey material procurement, material quality control and yard management for the entire project; Materials Manager will be assigned to lead the overall procurement and material management effort for the project and will report to the EPC Project Manager.
- Materials Manager will work in a close collaborative working relationship with Engineering, Quality, Construction, Material Yard Management, Suppliers, and Project Management Leads as all roles have a shared responsibility to ensure that quality materials are made available to construction when and where they are needed.
- All suppliers must be pre-approved by Procurement, Engineering and Quality based on compliance with standards and specifications, plant audits, where deemed necessary, prior customer references and past performance and experience.
- Compliance with the project's technical requirements and ability to meet delivery schedule factor prominently in the evaluation and selection process.

- Project quality is governed by [redacted] Quality Management Program and includes elements designed to ensure that all materials provided by suppliers meet the required specifications provided by engineering prior to the start of manufacturing.
- Inspection plan and audit schedule will be developed in conjunction with the supplier.
- Inspection and Test Plans (ITPs) and supporting documents and records will be used to verify conformity with specified contractual requirements.
- Periodic audits will be conducted during the manufacturing of key project materials.
- During the RFP response process, [redacted] has competitively bid all materials and discussed material manufacturing and delivery timelines to understand there is no inherent risk of issues preventing [redacted] from receiving material in accordance with the project schedule.
- When a supplier is selected, the contracting process ensures that key deliverables are contractually bound and required project specific terms and conditions are included in the contract.
- Warranty period and supplier's scope of responsibility to address deficiencies should they be found during construction or during the warranty period are included in the contract.
- Procurement risk captured at the project pursuit phase and incorporated into a Risk Register; risk assessed by severity/likelihood; mitigations identified and costs are addressed in project contingency.
- Material Management Process to manage logistics associated with project materials:
  - Receipt/inspection of materials at the yard
  - In-yard inventory management
  - Staging and shipping from material lay down yards to agreed-upon work locations
  - Managing overages, missing, damaged, and defective materials
- [redacted] organize and inventory materials and issue to the right of way; organized by foundation, pole storage, stringing and hardware related materials.
- [redacted] will implement and maintain systems and controls to manage a cradle-to-grave material management process.
- [redacted] allows the project to control the receipt, storage, and issuance of material to the construction site with transparency to all stakeholders on the status of all project materials.
- Construction liaison will be identified to coordinate the preparation of materials at the yard with the construction schedule.
- Materials team will work with the supplier to track all material beginning at the manufacturing location, ensuring accurate delivery schedules, shipping configurations and Quality Control.
- Materials Team will work with Project Management to shift delivery windows to ensure that material needed is available on time with a focus on efficient and on-schedule construction.
- Risks and mitigations:
  - Commodity costs tied to the London Metal Exchange; cost certainty for materials not tied to commodity prices allows for potential cost reductions to SPP should commodity prices decrease.
  - Manufacturing/Delivery schedule risk mitigated through discussions with major manufacturers and through competitive bid process.
  - [redacted] can lock in manufacturing windows in advance of contract signing and utilize many queue positions to acquire additional material if necessary.
- Preliminary list of potential suppliers identified for this project. All of the proposals listed provided preliminary pricing in support of this submittal.

Project Development Schedule/Scope - 25/23/92%
Project Scope/Specifications - 15/14/93%
Potential Risks/Mitigation Plans - 5/5/100%
Regulatory Approval Process/Mitigation Plans - 5/4/80%

Proposals D/E were judged "Best" for Project Scope/Specifications and Potential Risks/Mitigation Plans due to their detailed approach to identification and mitigation of risks.

Proponent for Proposals D/E has substantially negotiated project agreements with key partners and contractors.

Regulatory Approval Process and associated Mitigation Plans were judged "Good".

- Proposes to secure regulatory approvals by [redacted], complete 80% right-of-way acquisition by [redacted], commence construction in [redacted], receive all materials on site [redacted]
- Construction plan developed utilizing an integrated approach between contractors focusing on safety, not only during construction of the Project, but also to the public during the life of the asset; de-risk the overall Project and exceeds the requirements of the RFP and SPP MTDS.
- Project Agreements have been substantially negotiated between Respondent and the key partners and contractors; also intends to issue sub-contracts to third-party consultants and contractors to support Project development and construction.
- Conducted site visits and helicopter flyovers of the route throughout the RFP response period, conducting constructability reviews of the engineering design and building an easily achievable construction schedule with significant float.
- Schedule includes over [redacted] between the Project commissioning and the required Project in-service date.
- Key schedule risks include right-of-way (ROW) acquisition, environmental permitting and material delays.
- Respondents will coordinate efforts to prepare filings required to secure all regulatory approvals: [redacted]
    - FERC (FPA) - formula rate to SPP tariff; approval for certain risk-reducing incentives, e.g., abandoned plant; approval of Joint Ownership Agreement between partners to codify terms and conditions of owning and operating jointly-owned line.
- As development phase of the Project is completed, Project Team will evaluate the remaining float available and seek to mitigate any risk around construction by accelerating activities where practical.
- Respondent already obtained [redacted] of property rights required in Missouri; upon selection to construct the Project, Respondent will initiate a public process to evaluate and refine proposed route, and conduct right-of-way acquisition in accordance with the rules prescribed by KCC.
- Proposed scope provides details of route assessment, environmental studies and environmental permitting process post-award.
- Detailed, step by step description of Project scope and specs.

- Specific detailed mitigation plans for risks associated with ROW acquisition, environmental permitting, regulatory, procurement and construction.

Construction - 45/40/89%

Process and Plan - 25/22/88%
Project Manager and Staff - 20/18/90%

Proposals D/E are judged "Better" for both Process and Plan and Project Manager and Staff due to extensive experience in successfully constructing projects of similar scope.

Contractor has assigned key staff members to the project who bring successful track records of completing projects on time and within budget.

- [redacted] is responsible for all construction related efforts; agreement with [redacted] assigned key staff members to the project who bring successful track records of completing projects in similar scope and budget.
- Construction Plan is an aggregate of best practices stringent construction standards; Plan includes defining the work task, understanding the applicable restrictions, sequence of work, construction methods, roles and responsibilities, and planning of resources to complete the work on schedule; includes construction methods to streamline the construction process for the number of crews and disciplines that will be onsite.
- Detailed description of Sequence of Work provided.
- Site-specific Safe Work Plan: kept on the job location; before the start of each workday, the supervisor/foreman will conduct daily job briefings or Job Safety Analysis (JSA) with the personnel involved.
- During construction, a land agent will notify landowners prior to the start of construction and act as liaison between the construction group and landowners and their tenants, and also assist in the acquisition of any contractor required laydown areas, additional workspace or other interests that may be needed for construction.
- A key methodology in place on all projects is the concept of "self-audit".
- Three phase inspection process that highlights prior to any work beginning a thorough review of the project's quality requirements, documentation requirements, inspection requirements and owner representative's quality roles during the construction process.
- [redacted] Safety, Health and Environmental Plan is the cornerstone of our safety and health program and made Site-Specific for each project.

Commissioning Process - 10/9/90%

Proposals D/E are judged "Better" for Commissioning Process, as EPC contractor will perform detailed checks and acceptance testing of both the transmission line and fiber optic system after completing its detailed QA/QC procedures.

- Outage Plan: based upon the proposed route a total of [redacted] outages will be required from third parties during construction to safely construct the Project.
- [redacted] will perform detailed checks and acceptance testing of both the transmission and fiber optic system.

- Prior to performing the prescribed acceptance testing [redacted] will have previously concluded its detailed QA/QC procedures to verify that the line is in conformance with [redacted] standards; Foundation Acceptance will have been completed as well.
- List provided of additional testing to be completed.

Timeframe to Construct/Milestones - 20/16/80%

Proposals D/E judged "Good" for Timeframe to Construct/Milestones.

Potential project risks/mitigations based on previous experience and information gathered during the RFP response.

- Project construction schedule: [redacted]
- [redacted] and [redacted] have developed a detailed construction schedule by utilizing a detailed scope of work and identifying key risks to the overall project schedule.
- [redacted] has developed the sequence of work by planning to begin work at [redacted] due to the right of way option acquired during the RFP response phase of the Project.
- Crews will begin at the [redacted], working their way in a linear fashion towards [redacted].
- List of Key Milestones provided.
- Potential project risk/mitigations based upon previous experience and information gathered during the RFP response process:
    - ROW Acquisition - can move crews if some parcels are not yet acquired.
    - Material Quality - on-site representatives for QA/QC during fabrication for high risk material such as [redacted].
    - Subsurface Conditions - desktop geotechnical study as well as on-site drilling samples of soils to confirm the desktop study; transmission design developed to utilize [redacted]
    - Third Party Outages - developed expected outage schedule; will share with existing transmission owners early in Project Development phase to understand existing planned outages and other requirements; will allow [redacted] to adjust construction sequencing in the event that an outage may not be provided.
    - Weather - [redacted] days anticipated for weather days during construction; if additional weather days required, the [redacted] months of schedule float is sufficient to absorb these delays.

Experience/Track Record - 25/25/100%

Proposals D/E judged "Best" based on the proponent's experience in successfully completing projects of similar scope.

Proponent's organization for Proposals D/E formed specifically to develop, own, construct, acquire, operate, lease and otherwise manage parent company's strategic investments.

- Respondent organization formed specifically to develop, own, construct, acquire, operate, lease and otherwise manage parent company's strategic investment in FERC-regulated electric transmission infrastructure across the United States[redacted]

- Project Team brings decades of experience successfully constructing, operating, and maintaining thousands of miles of high voltage transmission lines.

[redacted]

Other

- Project wide risk discussion included covering risk and mitigation strategies for:
  - Regulatory
  - Routing/Environmental permitting
  - ROW Acquisition
  - Material Quality
  - Subsurface Conditions
  - Third Party Outages
  - Weather
  - Pricing Fluctuations
  - Manufacturing and Deliver Schedule Certainty Respondent organization formed specifically to develop, own, construct, acquire, operate, lease and otherwise manage parent company's strategic investment in FERC-regulated electric transmission infrastructure across the United States [redacted]
  - Project Team brings decades of experience successfully constructing, operating, and maintaining thousands of miles of high voltage transmission lines.

Proposal F

Environmental - 30/30/100%

Route Selection - 20/20/100%
Regulatory - 5/5/100%
Support Staff - 5/5/100%

All Environmental aspects of Proposal F were judged "Best" [redacted]

[redacted]

- Overall impacts to the environment and current land use reduced by:
  - Over [redacted], minimizing new clearing, ground disturbance, and direct potential impacts to sensitive habitats
  - Reducing the number of structures and foundations in cultivated lands, reducing crop lost to the structure foundations, and reducing challenges associated with tilling/spraying/harvesting operations around multiple sets of parallel structures
  - Reducing overall visual impacts of the new 345 kV Project [redacted]
  - Less land encumbered by easements, resulting in less land use limitations for private landowners
  - Lower impact footprint and overall frequency of entry for regular operations and maintenance activities, reducing impacts and inconveniences on landowners over the life [redacted]

Note: The remainder of notes for Proposal F - Environmental are identical to those found for Proposal G, which appear later in this document.

ROW - 30/30/100%

Acquisition - 20/20/100%
Regulatory - 5/5/100%
Support Staff - 5/5/100%

Proposal F is rated "Best" for all aspects of ROW Acquisition, Regulatory, and Support Staff, primarily because the proponent plans to use [redacted]

[redacted]

[redacted]

Note: The remainder of notes for Proposal F - ROW are identical to those found for Proposal G, which appear later in this document.

Procurement - 15/15/100%

Process - 10/10/100%
Support Staff - 5/5/100%

Proposal F was judged "Best" for Process and Support Staff, in large measure because of the collective buying power through partners' affiliated companies.

[redacted]

- Respondent, through its affiliated and subsidiary companies, have collective buying power; [redacted] is steeped in procurement expertise necessary to manage budgets; established processes, vendor relationships and necessary agreements in place to successfully develop the Project on time and within budget.
- Executed Engineering, Procurement, and Construction contract with [redacted] highly capable and experienced EPC team that will manage procurement activities.
- [redacted] proof of performance - [redacted] expertise to safely and efficiently meet project milestones related to budget and schedule.
- EPC contract executed and ready to implement upon issuance of notice to proceed; does not require any further negotiation or finalization.
- Sophisticated vendor qualification process to distinguish eligibility at the plant/facility level,
- Supply Chain works in conjunction with Engineering to ensure material requirements meet high standards while aligning with offerings from multiple suppliers, both foreign and domestic.
- Source selections for any particular project consider current inventory, delivery timelines, and any foreseeable impacts from approved non-domestic sources.
- Key Engineering and Project Manager technical experts' travel to fabrication sites to inspect quality of goods, conduct factory inspections, and witness owner acceptance tests.
- Prioritize domestic material production over non-domestic, wherever feasible.
- Confidence that all the procurement for engineering, project support, and construction labor, as well as material procurement already complete; certainty in Respondent's ability to execute on time and within budget in a highly volatile environment for labor and commodities.
- Detailed Procurement Plan and proposed Procurement Schedule allows time for common disruptions by keeping major equipment (poles) delivery off the critical path, and having vendors perform kitting tasks.
- To mitigate risk that can impact lead times for [redacted], Procurement and Material Management group will work with selected material suppliers to reserve production – without new financial obligation.

- Risk mitigation/recovery measures include:
  - Working with suppliers with existing positive experience and relationships
  - Ensuring contracts contain appropriate commercial terms to protect against issues
  - Sorting and kitting material at the manufacturing location, where conditions are best suited
  - Applying schedule float, as necessary
  - Conducting appropriate quality assurance/quality control at the material supplier's manufacturing location
  - Performing detailed quality control during material receipt Including line hardware spares to account for breakage, loss, or mis-fabrication, and integrating the management of construction contingency materials and spares so that material is available to address potential failure
  - Certifying appropriate material acceptance procedures and documentation at the work site so that the transfer of responsibility is transparent

[redacted]

- [redacted] which are based on already approved FERC Formula rates. [redacted]

Project Development Schedule/Scope - 25/23/92%

Project Scope/Specifications - 15/14/93%
Potential Risks/Mitigation Plans - 5/4/80%
Regulatory Approval Process/Mitigation Plans - 5/5/100%

Proposal F was judged "Best" for Project Scope/Specifications, "Good" for Potential Risks/Mitigation Plans, and "Best" for Regulatory Approval Process/Mitigation Plans.

[redacted]

The following items refer to the unique aspects of Proposal F. The remainder of notes for Proposal F - Project Development Schedule/Scope are identical to Proposal G and appear later in this document.

- [redacted]
- [redacted]
- Overall lower risk profile for quality, schedule, and cost in execution.

Construction - 45/43/96%

Process and Plan - 25/23/92%

Project Manager and Staff - 20/20/100%

Proposal F is judged "Best" for Process and Plan, which is only marginally less than the scoring for Proposal G due to the lack of detail in Proposal F [redacted]

Project Manager and Staff for Proposal F were judged "Best" [redacted]

(Notes for Proposals F & G for this section are identical)

- Respondent integrates ROW input into the construction planning effort early on, ensuring that the full scope of ROW needs (from temporary construction access, crane pad, and pulling station locations to long-term access agreements) are considered.
- Integrated, team approach ensures that ROW agreements include the entirety of construction needs; minimizes potential for delays.
- Project schedule addresses each of the project phases and the critical milestones required to successfully meet the energization timeline.
- Schedule will allow detailed monitoring and forecasting of activities, resources, and production efficiency utilizing a look ahead approach, and ensures focus on critical items and proactive project management.
- Schedule has over [redacted] of overall flexibility, including float and contingency components.
- Key transmission line construction elements include:
    - Mobilization and set up
    - Receiving of materials
    - Clearing, access, and Storm Water Pollution Protection Plan installation
    - Foundation installation
    - Structure installation
    - Conductor/OPGW installation
    - ROW restoration
- Local utility partner will provide on-site Transmission Construction Representatives to the Project to monitor construction practices and methods, inspect construction installation quality, assure adherence to safe work practices and programs, and assist the EPC Project Team in coordinating construction activities with other utilities.
- Authorized to require the EPC Project Team to make corrections to the work, if necessary.
- Project Implementation Team includes support from Engineering and Field Oversight with dedicated safety and quality standards, as well as subject matter experts (SMEs) for critical tasks.
- EPC Project Team will follow a proven and disciplined process, matching appropriate resources to ensure safe, on-time, on-budget delivery as demonstrated by:
    - Everyone on the team already engaged in the development of the Project; will continue to do so from Day One through the entirety of the Project.
    - Team started with clearly defined scopes and risks and developed a clearly defined execution plan.

- Project success will be defined in terms of safety, compliance to schedule, ability to maintain budget, adherence to Project quality requirements, and avoidance of disputes.
- Proficient coordination and communication at Project and program levels encourages innovative ideas that lead to Project success.

- Project Team also has specific experience and expertise.
- [redacted]
- All work will be scheduled through the OCA Switchyard Coordinator.
- EPC Project Team will work closely with Respondent to develop a project-specific Quality Plan based on the specific scope of work and requirements, and incorporate the TQM cycle.
- [redacted] assists employees across the Project spectrum (design team, managerial staff, crews, subcontractors, etc.) to become highly knowledgeable regarding Project specifications and requirements.
- During each of [redacted], meetings will be held to allow any stakeholder the opportunity to ask questions or identify concerns regarding construction quality, specifications, preparations, or safety.
- Highly experienced, well-qualified team to execute construction; includes personnel with more than [redacted] of combined experience in constructing high-voltage transmission projects in Kansas, Missouri and throughout U.S.; average team member has more than [redacted] of relevant experience.
- [redacted] retained to perform ROW clearing and to build access roads and install matting and pads; proven, industry-leader in quality, efficiency, and safety in clearing and access operations.
- ROW clearing subcontractor will perform a pre-construction walkthrough with environmental monitors and inspectors prior to initiating clearing.
- Access construction coordinated among ROW Agent, landowners, [redacted], and Environmental Permitting Compliance workers.
- [redacted] will install temporary access entrances to the ROW, including encroachments to and from existing roads and drives.
- Material Manager and Project Manager will review all IFC drawings, BOMs, plans, and other documents to create a comprehensive view of materials needed for construction.
- Criteria for location of laydown yards:
  - Ready-and-easy access for material delivery rigs
  - Well-draining grounds to prevent flooding and/or water damage to materials
  - Grounds that are easily patrolled by security
  - Grounds where material has adequate space to be managed
  - Minimal drive-time to and from construction/installation sites
- Detailed 5-step safety program
- Strategic Construction Plan that facilitates timely and accurate communication, clarifies expectations, and results in the execution of a safe, reliable transmission system with minimal overall impact to the local area.
- Plan to be ready to energize [redacted]; to mitigate schedule risk, also have identified [redacted] of contingency (construction and ISD) available to account for unknowns.

Commissioning Process - 10/7/70%

Proposal F is judged "Good", slightly below average, due primarily to the lack of detailed information on how Commissioning will be coordinated [redacted]

(Proposals F & G for this section are identical)

- Substantial completion of transmission line construction is essential to completing Project commissioning and energization.
- Respondent and EPC contractor have proposed a construction schedule that allows the line asset to be available early to coordinate outages, testing, and energization with incumbent utilities afterward.
- Commissioning Manager will coordinate and communicate with representatives from each party to establish the necessary outage requirements associated with the Project; critical during communications testing between substations, and during the phasing reviews that must be completed for the entire length of the line prior to energizing.
- TOs will be responsible for developing site-specific zones of protection, testing, and commissioning plans for the equipment at their respective existing substations.
- Respondent anticipates that its construction and installation work can be completed without the need for substation outages because its scope ends at the attachment point of the interconnect poles outside of the TOs' energized substations.

Timeframe to Construct/Milestones - 20/18/90%

Proposal F was judged "Better" for Timeframe to Construct/Milestones given that the total duration of the Project, from award to in service, is [redacted], which is more than adequate for pre-construction, all work disciplines, and testing/commissioning activities.

(Proposals F & G for this section are identical)

- Combined overall flexibility of [redacted] depending on how long it takes SPP from the date of the expected award to issuing the NTC for the Project; [redacted]
- Primary work streams most likely to impact the amount of Total Float are (i) Regulatory approvals, (ii) Permit acquisitions, (iii) Right of Way acquisition, and (iv) Construction activities, including foundations, structure setting and wire pulling operations.

[redacted]

Experience/Track Record - 25/22/88%

Proposal F was judged "Better" as proponent will employ a Project Lifecycle Management Process, which provides a structure to accurately scope and document projects from development to closeout.

(Proposals F & G for this section are identical)

- [redacted] Together the respondents own and operate [redacted]
- [redacted] field team is as strong as they come; extensive field leadership assigned to this Project with ample resources to complete the Project.

Other

(Proposals F & G for this section are identical)

[redacted]

Proposal G

Environmental - 30/27/90%

Route Selection - 20/18/90%
Regulatory - 5/4/80%
Support Staff - 5/5/100%

Proposal G was judged "Better" for Route Selection, "Good" for Regulatory, and "Best" for Support Staff.

[redacted]

- [redacted]
- Comprehensive Routing Study and environmental review identifies a Proposed Route that minimizes impacts on the environment, local agricultural land use, residential development, and other area land uses; also intentionally avoids:
    - Use of non-standard designs
    - Unreasonable Project costs
    - Restrictive permitting limitations
    - Other potential risk to regulatory approval
- Key objective of routing study was to identify a Proposed Route at a level of specificity to allow for an efficient and timely transition from study to project implementation upon Project award.
- Compiled an interdisciplinary team of key SMEs with significant experience in transmission siting, engineering, permitting, ROW, project management, and construction for the Routing Study; combined expertise from successful projects executed by Respondent partners and the EPC Contractors.
- [redacted]
- Used a 6-step iterative route development approach that included multiple phases of information gathering, route development, agency input, and coordination with local officials.
- Routing Study used a range of both quantitative and qualitative factors to identify the Proposed Route; methodology implemented for a wide range of projects [redacted]
- Routing Team coordinated with local government agencies/officials to assist the route development process in affected counties.

- Began process [redacted] by identifying a Study Area and developing routing concepts based on a range of major environmental and land use features that served as primary drivers for route development.
- [redacted]
- Routing Team developed more than [redacted] Study Segments to evaluate routing constraints and opportunities.
- Study Segments divided into [redacted]. Respondent iterative routing process evaluated a number of Study Segments in each geographic region.
- Routing Team worked diligently to identify a route that:
  - Minimizes overall impacts on natural and human environments
  - Circumvents indirect routes
  - Avoids unreasonable costs
  - Prevents special design requirements
- Proposed Route chosen because it is the shortest route (by 4 miles), inherently requiring less ROW, clearing, structures, access roads, and construction impacts compared to longer routes, as well as being the most cost effective.
- [redacted].
- Specifically minimizes further fragmentation of area natural resources and land uses, reduces the number of new access roads and costly and impactful heavy angle structures; reduces overall effects to constructability.
- Route spans fewer Special Aquatic Life Use Waters streams and floodplains, requires less tree clearing, and minimizes impacts to natural communities as well as a prairie chicken range.
- Proposed Route:
  - Reasonably minimizes adverse impacts on area land uses, and the natural and cultural environment
  - Minimizes special design requirements and unreasonable costs
  - Can be constructed and operated in a safe, timely, and reliable manner
- [redacted] collaborative relationships with the USFWS; USACE Kansas City and Little Rock offices; KDWPT; and Missouri Department of Natural Resources (MDNR) will enhance the permitting process and contribute to the overall success of this Project.
- Upon award, will initiate a series of public open houses to gather landowner input to finalize the route selection process.
- In-house team will allow for timely, cost-effective communication and completion of this Project.
- Knowledge, experience, and strategies of the team and its long-standing contractor relationships with respect to each of the major permits and consultations required for the Project.
  - Environmental Management & Permitting Team
  - Natural & Cultural Resource Surveys
  - Environmental Permitting Plan
  - Environmental Management During Construction
- Environmental Team maintains working relationships with environmental regulators responsible for resources in the Study Area and throughout the region; [redacted]

ROW - 30/27/90%

Acquisition - 20/17/85%
Regulatory - 5/5/100%
Support Staff - 5/5/100%

Proposal G was judged "Better" for ROW Acquisition and "Best" for Regulatory and Support Staff.

[redacted]

- ROW section of proposal addresses the following:
  - Best Utility Practices and ROW Width Decision
  - ROW Acquisition Team Experience and Expertise
  - Due Diligence Performed to Support ROW Acquisition Plan
  - ROW Acquisition Plan (approach and methods to execute upon award)
  - ROW Acquisition Services (construction support and non-environmental permits)

[redacted]

- [redacted] ROW width also maintains equilibrium between environmental impacts and the safe and affordable construction, operation, and maintenance of the line; design reflects:
  - Reasonable Capital project cost
  - Economical and efficient ongoing maintenance
  - Preserve Habitat to the extent feasible
  - Maintain maximum pre-existing land use, in this case, pasture and agricultural
  - Favorable aesthetics: [redacted]
- Project ROW acquisition assigned to contracted EPC Team who will use one of the most trusted contractor partners [redacted]
- Founded in [redacted] has been involved in successfully planning, managing, and executing over [redacted] of ROW acquisition projects throughout North America. [redacted] has successfully performed ROW services on a multitude of Greenfield and rebuild EHV electric transmission projects ranging from 345 kV to 765 kV.

- Land acquisition contractor has worked within, and throughout, Kansas and Missouri for many years; staff have experience acquiring land rights in the [redacted] counties crossed by the Project.
- Safety Officer implements the [redacted] safety program, preparing a customized safety plan for each [redacted] project.
- Expert ROW Team already completed the following activities:
    - Completed real estate market data study review of area land sales and valuations (performed by a state-licensed appraiser for Kansas and Missouri)
    - Executed market data study, identifying the [redacted] contained within Proposed Route
    - Conducted multiple site visits of the Project area, evaluating numerous study segments within the approximately [redacted]
    - Undertook ROW analysis, reviewing width, parcel considerations, and compatibility of present land use
    - [redacted]
    - Reached agreement for the necessary line crossings for the new Wolf Creek-Blackberry line to cross other transmission lines along the route.
    - Meet criteria for a full dead-end structure on each side for their lines to be crossed; cost is already included in the proposal.
- Hired [redacted], an experienced, local real estate consultant to perform the detailed property parcel and market data study using publicly available information.
- ROW Plan includes:
    - [redacted] engineering work completed based on our Proposed Route
    - Geotechnical research performed by Engineering
    - Analysis of cultural, historical, and environmental reviews to inform the Routing effort
    - Agency engagement
- Anticipate completing ROW acquisition activities [redacted] from award, which is [redacted]
- Respondent uses an established code of conduct [redacted] to guide all landowner interactions for easement acquisition:
    - All communications must be based on information and made in good faith.
    - All communications and interactions with property owners and occupants must be respectful and reflect fair dealing.
    - All communications and interactions with property owners and occupants must respect the privacy of property owners and other persons.
- Project team's goal is to achieve over [redacted] or better voluntary settlement.
- ROW team tasks:
    - ROW execution planning and refinement of field study and desktop research, updating for final approved route
    - Conduct additional land/title research
    - Engage landowners to reach agreements on terms to acquire the right to construct the line on their properties
    - Obtain access permission for surveying, etc.
    - Secure rights for construction laydown, wire pulling sites, and temporary access road agreements or other needed contracts

- Make inquiries and record special conditions for reference and use by surveying and construction teams
- Provide a primary point of contact for landowners throughout the Project
- Hire for the final land valuation study and appraisal services
- Document preparation and data management
- Eminent domain support

- ROW/Construction support services:
  - Construction liaison support (to landowners, third parties with impacted utilities, railroads, pipelines, roads/highways, schools, etc.)
  - Non-environmental permitting
  - Ensure any damages incurred are resolved in a timely and professional manner
  - Quality assurance and quality control
- [redacted] Appraiser/team expected to start [redacted]
  - Perform independent real estate market study and parcel research
  - Analyze the impact of mineral interests within the easement corridor
  - Review the value consideration of the type of property interest being acquired, such as fee, permanent easement, access right, or temporary easement
  - Provide value analysis and value estimate for impact to the property caused by the Project
  - Prepare site-specific appraisals, where required, to successfully negotiate a settlement with a property/landowner
  - Complete appraisals that are required for the eminent domain process
- [redacted] ROW Lead Agent will communicate with the Project team to escalate any concerns to Respondent's EPC Team Project Management to make them aware of any specifics affecting successful negotiation with landowners.
- [redacted] ROW agent has developed a robust and user-friendly ROW project tracking and management application and database for successful management of ROW projects - [redacted] one of the most comprehensive land records management software solutions in the industry.
- [redacted] ROW Agents will:
  - Provide construction support throughout the build;
  - Attend all necessary construction meetings to obtain correct and current information and provide it to landowners;
  - Involved in Construction team's pre-construction activities, including structure staking by the survey company, so they can notify property owners when and why construction activities are planned;
  - Conduct negotiation and settlement of all damages with landowners/tenants that may arise before, during, or after construction.
- QA/QC measures embedded throughout the ROW process, starting with selection of a top-tier contractor, [redacted], and a highly experienced full-time staff leading the ROW effort; each process is structured in a manner that ensures multiple levels of review prior to execution.
- [redacted] ROW agent responsible for obtaining or supporting Respondent/EPC Team in obtaining non-environmental permits from appropriate agencies.
- Continually evaluate constructability considerations leading up to the construction phase.
- Integrate ROW input into the construction planning effort early on, ensuring that the full scope of ROW needs (from temporary construction access, crane pad, and pulling station locations to long-term access agreements) are considered.

- Integrated, team approach ensures that ROW agreements include the entirety of construction needs; minimizes the potential for delays that can occur late in the construction effort as a result of poorly developed landowner agreements.
- Comprehensive Risk Register allows Respondent to document, categorize, and better manage risk; risk mitigation methods include adequate float within the schedule to manage any delays associated with these risks.

Procurement - 15/15/100%

Process - 10/10/100%
Support Staff - 5/5/100%

Proposal G was judged "Best" for Process and Support Staff, in large measure because of the collective buying power through partners' affiliated companies.

[redacted]

(Proposals F & G for this section are identical)

Project Development Schedule/Scope - 25/25/100%

Project Scope/Specifications - 15/15/100%
Potential Risks/Mitigation Plans - 5/5/100%
Regulatory Approval Process/Mitigation Plans - 5/5/100%

Proposal G was judged "Best" for all aspects of Project Development Schedule/Scope.

[redacted]

- Schedule tracking and management will utilize [redacted], a project management software tool used worldwide; able to manage large and complex projects; enables users to budget, prioritize, plan, administer, and manage multiple projects, optimize limited, shared resources, control changes, and consistently move projects to on-time and on-budget completion.
- [redacted] serves as a single comprehensive framework for project development, planning, and execution; product of deep collaboration between the utility partner SMEs and EPC functional experts; ensures that logic within each work stream and cross-functionally reconciles with field-earned experience.
- Major factors contributing to the critical path schedule include:
  - Timing of SPP proposal and award process
  - Receipt of necessary regulatory approvals, including CCNs
  - Acquisition of ROW, permanent transmission line easements
  - Environmental permitting
  - Construction of the new Wolf Creek - Blackberry line

- Basis of Schedule document is the cornerstone for development of the [redacted] and includes baseline scheduling assumptions, identification of major project activities, risk, and planned Project execution strategy.
- [redacted] views commonly used include: 2-Month Look-Ahead Schedule (focus on near term activities), Variance Analysis (Month to Month or week to week changes in scheduled activities), and Critical Path Schedules (used for monitoring and controlling the activities that directly influence overall on-time completion of the project and support development of any schedule recovery plans if a delay is encountered).
- Primary work streams most likely to impact amount of Total Float are (i) Regulatory approvals, (ii) Permit acquisitions, (iii) ROW acquisition, (iv) Structure setting and wire pulling operations; include the most interaction with the public and agencies, which takes a significant amount of effort, care, and diligence.
- [redacted]
- Key land surveying activities will begin in [redacted] with Land Valuation Studies.
- [redacted]
- Experience of all involved parties enable Respondent to provide a realistic schedule [redacted] for the Project based on significant development work already performed.
- Specific Risk Categories assessed include: Construction, Engineering, Environmental, Finance, Regulatory, Outages, Procurement, and ROW
- [redacted]
- [redacted] has allocated a total of [redacted] in Project contingency dollars resulting from their risk assessment; identified [redacted], each of which have a response plan to ensure the terms of the contract will be met.
- Conducted an independent risk evaluation of retained risk to ensure no gaps or duplication of risk impact adjustments [redacted]
- Comprehensive Risk Register shows a thorough analysis of numerous risk for the Project, addressed through a purposeful and efficient combination of avoidance (design/contract out), mitigation, and contingency planning.
- Scope of work for this contract:
    - Backed by an experienced and creditworthy counterparty [redacted]
    - Includes final siting diligence, surveying, ROW acquisition, and acquisition of pertinent environmental and non-environmental permits.
    - Implementation of all permitting mitigation requiring design, installation, or construction techniques or scope
    - Design and engineering specified to both SPP and Respondent requirements.
    - Procurement of all materials using Respondent's approved material vendors.

- Provides for all construction activities, including installation, clearing, access roads, commissioning and clean-up activities.
- Outlines payment of construction damages for roads and landowner properties.
- [redacted]
- Substantial warranty provisions provided on all installed equipment.
- Notes the significant requirements for continual update of the Project schedule during construction, with the ability for Respondent to require implementation of recovery plans (including step-in rights, if necessary) to correct issues.
- [redacted]

- Procurement Plan and proposed Procurement Schedule allows time for common disruptions by keeping major equipment (poles) delivery off the critical path, and having vendors perform kitting tasks so our people don't have to do so in adverse weather.
- Detailed table of Risk Category, Risk Description, Risk Driver and Mitigation Steps.
- [redacted]

Construction - 45/45/100%

Process and Plan - 25/25/100%

Project Manager and Staff - 20/20/100%

Proposal G was judged "Best" in both Process and Plan and Project Manager and Staff due to knowledge and experience [redacted]

Highly experienced and well-qualified construction team includes personnel with more than 180 years of combined experience constructing EHV transmission projects.

(Proposals F & G for this section are identical)

Commissioning Process - 10/8/80%

Proposal G is judged "Good".

Proponent for Proposal G and its EPC contractor have proposed a construction schedule that allows the line to be available early to coordinate outages, testing and energization.

(Proposals F & G for this section are identical)

Timeframe to Construct/Milestones - 20/18/90%

Proposal G was judged "Better" for Timeframe to Construct/Milestones given that the total duration of the Project, from award to in service, [redacted], which is more than adequate for pre-construction, all work disciplines, and testing/commissioning activities.

(Proposals F & G for this section are identical)

Experience/Track Record - 25/22/88%

Proposal G was judged "Better" as the proponent will employ a Project Lifecycle Management Process, which provides a structure to accurately scope and document projects from development to closeout.

(Proposals F & G for this section are identical)

Other

(Proposals F & G for this section are identical)

III: Operations

Significant effort was expended to carefully read and review all information and data that was included in the response form as well as in the attachments provided in all Proposals using the factors listed above for each criterion. This evaluation has considered not only the adherence to best operations and maintenance practices but also the robustness of the operations and maintenance practices proposed for this project. The evaluation also focused on proposed plans for compliance with NERC requirements for transmission owners and operators as well as safety. In addition, the evaluation considered whether the Respondent has demonstrated that it has assembled, or has a plan to assemble, a sufficiently sized team with the manpower, equipment, knowledge, and skills required to undertake operations and maintenance of this Project over its life.

Following is a list of the major factors, along with other considerations, that were taken into account in evaluating each criterion/sub-criterion for the Operation category proposal. The purpose was to assess Respondents ability, experience, expertise, plans/processes/equipment/tools proposed for safe operation and maintenance of the Wolf Creek – Blackberry 345 kV line over its life.

1. **Control center operation**
    a. Control Center Redundancy and Reliability; Provision of primary and backup control centers; location, distance between them, etc.
    b. Staffing, experience, resumes, organization chart.
    c. Agreement, if the control center belongs to a second or third party.
    d. Specific plan to integrate the Project.
    e. Project's system control center operations program details such as switching and outage coordination, and all real-time monitoring tools including real-time visualization as well as situational awareness.
    f. Weather tracking tool.
    g. Historical performance/experience of the primary and backup control centers, especially during severe weather conditions in the recent past.
    h. Operators' switching step for outage coordination success rates.
    i. Recent NERC audit outcome/experience associated with the Primary and backup control centers (TOP function).

2. **Reliability matrices**
    a. Total Outage Frequency for the last five or so years.
    b. Historical reliability metrics for lines like this Project.
    c. Plan to communicate with substations and RTO.
    d. Provision of ICCP links to the RTO established to transmit and receive the Project data from the substations.
    e. Switching accuracy
    f. Project specific outage coordination with the RTO.
    g. Processes and tools for monitoring reliability and availability reporting.
    h. Switching and communication plans as well as planned and unplanned outage coordination plan.

i. Availability of advanced storm tracking and forecasting tool to forecast and track thunderstorms, lightning activity, tornados, ice storms, and high winds that could impact the Project.

3. **Storm/Outage and Emergency Response Plan**
   a. Estimated outage response time. Primary and Secondary locations, distance, and response time. Primary contractor support time and distance.
   b. Spare parts location and delivery time. Is the location very close to the project? Could that be a problem because spares location could also be impacted by the same storm and could potentially hamper the delivery time and repair/restoration effort?
   c. Pre-defined storm/outage response team with defined roles and responsibilities.
   d. Organization chart and resumes of the key members of the response team.
   e. Emergency response plan
   f. Financial strategy to address catastrophes.
   g. Contractor resources - transmission line contractors, vegetation management contractors, helicopter services, equipment suppliers, and material suppliers. List and Copies of agreement or MOU.
   h. Recent experiences of the Respondent and primary contractor demonstrating the emergency restoration capabilities to address major events.
   i. Project specific continuous weather monitoring and advanced storm tracking and forecasting tool.
   j. Estimated time to complete demolition and reconstruction of damaged one mile of transmission line

4. **Maintenance Staff/Training**
   a. Organization chart, responsibilities and staffing assignment specific to this Project.
   b. Staff experience, resumes.
   c. Safety training and records.
   d. In addition to typical OSHA, fall protection, personal protective equipment, first aid training requirements.
   e. Transmission line specific safety training covering items like induced current, grounding, clearance procedures, and transmission specific equipment.
   f. Contractor training.
   g. NERC reliability standards related training.
   h. Vegetation management training - R/W clearance and NERC
   i. Nuclear substation coordination training, where applicable
   j. Agreements, if any.

5. **Maintenance Plan**
   a. The maintenance program - Predictive and preventative maintenance
      i. Maintenance program strategy to guide maintenance and inspection frequency,
      ii. Maintenance budget provision and estimate of monetary reserves.
      iii. Frequency of the maintenance plan updated to perform maintenance considering the condition of equipment, timing of outages, and resources required.
   b. Who will do the maintenance? Internal staff or contractor or both? Agreement needed, if contractor is to perform maintenance.

c. Transmission line inspection types and frequencies for maintenance
    i. Ariel patrol for line and vegetation maintenance,
    ii. Walking patrol inspections,
    iii. Vegetation maintenance - planned vegetation treatment emergency veg treatment per aerial inspection.
d. Wildfire prevention.
e. Financial Strategy for Maintenance Activities
f. Line maintenance training program

6. **Specialized Maintenance Equipment and Spare Parts**
    a. Maintenance equipment list and inventory
    b. Plan to maintain specialized equipment
    c. Vegetation management equipment
    d. Location and distance of specialized maintenance equipment and spare parts.
    e. Contractor's list of maintenance equipment and spare parts; location, delivery time estimates, and distance.
    f. Any shared spares as a backup?
    g. Agreement for shared spares?

7. **Restoration Experience/Performance**
    a. Project specific emergency restoration capabilities for major events for the Proponent and primary contractor.
    b. Recent experiences in similar environments to the Project

8. **Maintenance Performance/Expertise**
    a. Maintenance performance experience with lines in the state/region for facilities similar to the Project over the last five or so years, such as
        i. Number of structures inspected and maintained.
        ii. Vegetation management work experience
        iii. Examples of recent restoration events and work for similar projects
    b. Maintenance team expertise

9. **NERC Compliance Process / History**
    a. Project specific processes and procedures to assure NERC compliance
    b. Integration of the Project into the Proponent's existing internal NERC compliance programs, controls, and processes.
    c. NERC registration requirements associated with this Project
    d. Training
    e. Vegetation management program for NERC compliance
    f. Recent NERC audit history and outcome

10. **Internal and Contractor Safety Program**
    a. Documentation of internal safety programs and past performance
    b. Specifics of how the Project will be integrated into the existing safety programs.
    c. Safety manual

11. **Contractor safety program**
    a. Description of the safety programs specific to this project detailing existing safety programs and past performance, safety training and certification program
    b. Safety manual.
    c. Specifics of how the Project will be integrated into the existing safety programs.

12. **Safety performance record**
    i. Documentation detailing safety plans for similar projects and the past performance.
    ii. DART history for the last five years (Days Away, Restricted or Transferred).
    iii. EMR (Experience Modification Rate) history for the last five years or so.

Furthermore, the information provided by each Respondent was used to analyze how much better one Respondent can do compared to the other Respondents. If the information provided to evaluate these factors and other considerations were judged insufficient, then that Respondent was scored less as compared to the sufficient relevant information provided for evaluating the same criterion by other Respondents. The overall Operation scores are tabulated below, followed by the salient points and other information of each proposal used for this purpose, including the information that was not available for the complete assessment and comparison.

Operations Point Allocation by Criterion and RFP Respondent

Operations (Operations/Maintenance/Safety) 250 Points *Measures safety and capability of an RFP Respondent to operate, maintain, and restore a transmission facility*	Sub-criteria	Weight	Total Pts	A	B	C	D	E	F	G
3a) Operations	3a.1) Control Center Operations	10%	25	22.5	22.5	25	19.25	19.25	25	25
	3a.2) Reliability Metrics	10%	25	25	25	25	23.25	23.25	15	25
	3a.3) NERC Compliance Process History	10%	25	25	25	23.75	21.88	21.88	25	25
	Sub-Total Criteria Pts	30%	75	72.5	72.5	73.75	64.38	64.38	65	75
3b) Maintenance	3b.1) Storm Outage and Emergency Response Plan	10%	25	22.5	22.5	25	20	20	15	25
	3b.2) Specialized Maintenance Equipment and Spare Parts	8%	20	16	16	16	15	15	11	18
	3b.3) Maintenance Plans	8%	20	20	20	20	18	18	12	20
	3b.4) Maintenance Staffing/Training	8%	20	20	20	20	18	18	12	19
	3b.5) Maintenance Performance/Expertise	6%	15	15	15	14.25	7.5	7.5	14.25	15
	3b.6) Restoration Experience/Performance	6%	15	15	15	14.25	13.5	13.5	9	15
	Sub-Total Criteria Pts	46%	115	108.5	108.5	109.5	92	92	73.25	112
3c) Safety	3c.1) Internal Safety Program	8%	20	20	20	20	20	20	20	20
	3c.2) Contractor Safety Program	8%	20	18	18	20	20	20	20	20
	3c.3) Safety Plan Similar to This Project and Performance Record	8%	20	20	20	20	18	18	18	18
	Sub-Total Criteria Pts	24%	60	58	58	60	58	58	58	58
	Scoring Category Total	100%	250	239	239	243.25	214.38	214.38	196.25	245

Proposals A and B

Proposals A and B provided very detailed information for evaluation.

3A.1) Control Center Operations

- Respondent provided the details of the primary control center from where the real-time monitoring, switching and outage coordination for the proposed Project will be carried out. A fully operable redundant backup control center is located [redacted] from the primary control center. Both the control centers are operated by NERC-certified transmission system operators (TSOs) with an average of over 10 years of experience.
- Recent experience with maintaining full control and keeping its system fully energized in [redacted] The respondent indicated that throughout the entire event, both control centers, as well as the assets they control, remained fully operational.
- A chart of the Respondent's proposed organizations showing the reporting relationships of the maintenance and operations organizations including compliance management functions along with the resumes of the primary and lead personnel provided to assess this criterion.
- Project's Integration plan into the control center not provided to assess this criterion. Project's system control center operations program details such as switching and outage coordination, as well as situational awareness tools with advanced capabilities for real-time monitoring not provided for this criterion.
- Access to continuous weather monitoring and advanced storm tracking and forecasting software.

3A.2) Storm/Outage and Emergency Response Plan

- The Respondent indicated that the outage response team will have a permanent location at [redacted] Additional local support will be provided as needed by its primary contractor from [redacted] The agreement with the Primary contractor was not provided.
- The Respondent indicated that spare parts for the Project will be stored near [redacted] and can be delivered anywhere on the line within [redacted] This spare strategy could be a problem because spares location could also be impacted by the same storm and could potentially hamper the delivery time and repair effort.
- Pre-defined storm/outage response team with names (including designated backup) will be activated in the event of an emergency with each team member having defined roles and responsibilities along with the organization chart of the response team provided to assess this criterion.
- Well documented emergency response plan. A designated finance manager, who is a part of the emergency response team to ensure availability of adequate working capital.
- Maintaining [redacted] to complete maintenance and a working capital revolver to rebuild [redacted] provided as part of the financial strategy to replace/rebuild the line following catastrophes.
- Respondent maintains master service agreements with transmission line contractors, vegetation management contractors, helicopter services, equipment suppliers, and material suppliers to supplement its staff and resources as may be necessary. Eight agreements listed but copies of the master agreement and eight other agreements to prove commitments not provided to assess this criterion.

- Recent experiences demonstrating the emergency restoration capabilities for major events of the Respondent and primary contractor provided to assess this criterion.
- Access to continuous weather monitoring and advanced storm tracking and forecasting tools.
- The proposal indicated the ability to complete demolition and reconstruction/restoration of [redacted].

3A.3) Reliability Metrics

- Respondent provided data on total Outage Frequency for the period 2017 to 2019. The outage frequency is declining.
- Plan to communicate with the Wolf Creek and Blackberry substations and SPP described in detail.
- Respondent described the Project specific outage coordination with SPP in detail.
- Switching and communication plans as well as planned and unplanned outage coordination plans described in detail.
- Advanced storm tracking and forecasting software to forecast and track thunderstorms, lightning activity, tornados, ice storms, and high winds that could impact the Project described in detail.

3A.4) Restoration Experience/Performance

- Respondent described Project specific emergency restoration capabilities for major events for the Proponent and primary contractor and provided recent experiences data for 345 kV lines demonstrating emergency restoration capabilities to address major events.

[redacted]

- In addition, the Respondent also indicated that its primary contractor has similar experience in maintenance and emergency response.

3A.5) Maintenance Staffing/Training

- The respondent provided:
    - Maintenance organization chart and responsibilities including resumes of key personnel. Provided to assess this criterion. These individuals have, on average, 28 years of industry experience.
    - Safety training manual.
    - Three-year training records.
    - Project specific maintenance plan and process - [redacted]
    - Vegetation management personnel training.
- The training completed by each employee is tracked in the computerized maintenance management system (CMMS). In addition to typical OSHA, fall protection, personal protective equipment, first aid training requirements, field personnel complete transmission specific safety training covering items like induced current, grounding, clearance procedures, and transmission specific equipment.
    - Contractor training not described.

3A.6) Maintenance Plans

- The Maintenance Plan for the Project is described in detail. The maintenance program will utilize a combination of predictive maintenance and preventative maintenance. Annually, the maintenance team will update a detailed [redacted] to perform maintenance considering the condition of equipment, timing of outages, and resources required. The [redacted] is used to guide the maintenance budget and the level of monetary reserves needed for the Project.
- All maintenance activities for the Project will be managed with internal staff. Contractors will provide support on an as needed basis.
- Annual aerial patrol for line and vegetation maintenance; [redacted] walking patrol inspections, vegetation maintenance; planned vegetation treatment no more than [redacted]; emergency vegetation treatment based on the annual aerial inspections.
- Transmission Line Inspection Types and Frequencies include [redacted] A list of components to be inspected provided – specific to age, critical nature of the line, asset location considerations including weather.
- Vegetation management practices and procedure described in detail.
  - Aerial inspections shall be conducted annually; ground patrol based on the results of the aerial patrol [redacted]; Planned Vegetation Treatment no more than [redacted]. The proposal emphasized training and wildfire prevention.
  - Respondent utilizes a computer-based transmission line inspection tool to enable more accurate and intelligent field data collection, report creation, and historical analyses.
- The proposal covered the financial strategy to address catastrophes.

3A.7) Specialized Maintenance Equipment and Spare Parts

- The Proponent will use its existing modern fleet of transmission line and vegetation management equipment to maintain the Project and respond to outages along with its primary contractor's equipment.
- Proponent indicated that the transmission line and vegetation management equipment is sufficient to perform the anticipated maintenance for the Project.
- In addition, the Proponent maintains agreements with its primary construction contractor to provide maintenance and emergency repair services. The contractor has significant equipment approximately 100 miles from the Project in [redacted]
- The Proponent will own the local spare inventory and will store and maintain at its transmission maintenance facilities near the Project [redacted] This could be a problem if the same severe event hits the Wolf Creek – Blackberry line in the area where spares are located, which could result in delay in response and restore time.
- The Proponent provided a detailed inventory of spares for the project including plans to locally maintain the structures sufficient to replace one mile of transmission line with additional spares at a secondary location.
  - The proposal lacks the plan to maintain specialized equipment to ensure the availability when needed.

3A.8) Maintenance Performance/Expertise

- [redacted] maintenance summary experience of the crews that will be utilized to maintain this Project summarized in a tabular form along with the vegetation management work experience/history

3A.9) NERC Compliance-Process/History

- Respondent indicated that the Project would be integrated into its NERC compliance program leveraging its existing policies and procedures, and its existing compliance staff.
- Respondent provided an organization chart and résumés of the responsible staff for NERC compliance. Individuals have, on average, 29 years of industry experience.
- Project specific NERC compliance matrix provided to assess this criterion.
- Respondent will register with the [redacted]
- Vegetation management plan described in detail to comply with FAC-003.Compliance items of particular importance for the Project are vegetation management (FAC-003) and facility ratings (FAC-008) emphasized.
- Respondent indicated that it has dedicated staff that perform regular internal reliability audits to ensure that they are "audit ready" at all times.
- Respondent's most recent NERC Operation and Planning audit [redacted] found that the Respondent had a commitment to "promote a healthy compliance culture within its organization" with no findings of potential non-compliance, areas of concern, or recommendations. "The report emphasized that the Respondent has a very good internal compliance program and culture.

3A.10) Internal and Contractor Safety Program

- The Project will be integrated into the existing safety programs.
- Safety standards include the rules, practices, procedures, training, and equipment to safely operate and maintain the Project including Project Specific Safety Considerations: Emergency action plan, Hazard assessments, Induced current included.
  - Certification requirements addressed.

3A.11) Contractor Safety Program

- Contractor safety program in place; attachments provided. Very brief description.

3A.12) Safety Performance Record

- The OSHA Recordable Incident Rate (Incident Rate) and Days Away Restricted Transferred (DART) Rate for the last 6 years are provided in a tabular form. Safety record consistent. Incident rate [redacted] DART rate [redacted] which is excellent.
- The Proponent's safety record is reflected in its Experience Modification Rate (EMR) for last four [redacted] which is good.
- The primary contractor for the Project has developed a Project specific health and safety plan, which is included,
- Primary contractor provided the safety record for the last six years provided to assess this criterion.

Proposal C

This Proposal provided very detailed information for evaluation.

3A.1) Control Center Operations

The Respondent indicates that while preparing the proposal in preparation for establishing operations for this Project, its Project team performed an assessment of fitness of its existing processes, procedures, tools, training, and personnel that will allow it to perform the operations function of a TO as well as a TOP for the Project.

- The Respondent provided the following to assess this criterion:
  - [redacted] that will be operating and maintaining the facilities specific to this Project on behalf of the Respondent.
  - The location of the primary and backup control centers. The primary and secondary control centers are [redacted]. The control center has [redacted] NERC-certified transmission operators (reliability coordinators certified) and have completed Parent company's formal switching training programs. The control center staff have a range of industry experience of over 19 years and the Senior Operations manager has over 35 years of control center experience.
  - Organization chart with resumes of key personnel along with operations roles and responsibilities for the key O&M activities assigned for the project.
  - Copies of relevant agreements provided showing the well preparedness of the Respondent to take on the operations and maintenance responsibilities.
    - Agreement with the Primary and backup control center entity.
    - Master agreement.
    - Contractor maintenance agreement.
    - O&M Vendor support service agreements/purchase contracts.
  - Example of the recent experience of - [redacted]
  - Project specific operations integration plan described in detail.
- The control center operations program will include switching and outage coordination that will use all real-time monitoring tools including real-time visualization tools (grid wide area view, line operational status, ROW cameras, weather tracking and alert, galloping monitoring, protection information and disturbance alert systems)
- Coordination associated with the nuclear power plant experience.
- Respondent's affiliates successfully completed [redacted] switching steps each year with an accuracy rate more than 99.99%.
- To allow for real time visualization of the Project facilities, cameras will be installed to the line structures at specific points on the ROW. List of camera locations provided to assess this criterion.

3A.2) Storm/Outage and Emergency Response Plan

- The Respondent included the storm/outage and emergency response plans specific to this project including source and location of resources and past emergency restoration performance and experience.
- The Respondent indicated that it will use the Proponent's parent company's existing facility [redacted] Field Operations will be performed by 2 dedicated staff [redacted] supported by an additional 7 HV Field Technicians, and a team of 70 subsidiary technical staff [redacted], and specialist contractors in the region. The Proponent field operations team members will be available to be on-site within [redacted] of being notified by the automatic system.
- Examples of recent restoration experience provided to assess this criterion.
- The Organization chart showed the Field Operations team that will manage day-to-day activities for the Project and provide a 24/7 emergency call-out capability.
- The Project will utilize protection system features that provide advanced monitoring of system conditions and directly communicate status to the Proponent's response team.
- The Respondent indicated that the primary contractor will be available in the vicinity. The contractor will mobilize a minimum of [redacted]
- The proposal included the Forced Outage or Emergency Events Response Times - The local base of field operations for Respondent staff will be within [redacted] of the Project midpoint.
- The proposal provided the following:
  - Contractor's Line Equipment in the Region.
  - List of Vendors and Scope of Services.
  - Example of Forced Outage and Emergency Repair Events for Transmission Line.
  - Transmission Line Restoration Plan.
  - Wolf Creek Nuclear Power Plant Access and Emergency Repair Considerations and coordination plan.
- For special equipment not owned by Proponent has executed a Corporate Services Support Agreement (copy provided) to provide the support needed to respond to a forced outage and emergency events, including logistics, spares, aviation, and weather services.
- Unplanned event response - The Respondent will utilize protection system features that provide advanced monitoring of system conditions and directly communicate status to the Proponent response team.
- The Respondent indicated that it has an Emergency Preparedness business unit, which ensures organizational readiness across all threats and hazards.
- Severe Event Process and transmission line restoration plan described in detail.
- The Respondent developed a plan to replace [redacted]

3A.3) Reliability Metrics

- The proposal described the specific operations plan, including monitoring, switching, and outage coordination specific to this project.
- Respondent provided an example of [redacted] historical reliability metrics [redacted]
- The switching accuracy has averaged over 99.995% accurate [redacted]

- The availability of the project has also been high with only a slight decrease in availability [redacted]
- Experience with managing and coordinating the Projects reliability performance reporting, switching coordination, and outage coordination with SPP and other RTOs.
- [redacted] – Respondent's affiliates, which will be fully leveraged, already operate and maintain [redacted]. The Respondent indicated project area experience and established switching coordination, planned outage and operating coordination experience and protocols with [redacted]
- Switching coordination manual provided to assess this criterion.
- All switching personnel are required to complete initial switching certification and annual refresher training.
- Respondent's listed experience in monitoring, analyzing, and reporting availability metrics demonstrate its capability to sufficiently provide any reporting obligations in accordance with SPP requirements.
- Proposal included the Availability and Performance Indicators, such as Employee, Cost and Environmental, Availability/Reliability.

3A.4) Restoration Experience/Performance

- The Respondent described restoration experience for the last [redacted] for projects similar in size and scope including recent mutual support [redacted]
- The Respondent continuously works to improve its response plans to catastrophic events by bolstering guidelines and regularly training staff.
    - Undertakes a full week of mock storm drill exercises once a year.
- The Respondent also provided the Emergency Support Contractor's Severe Event Restoration Experience.

3A.5) Maintenance Staffing/Training

- The Respondent indicated a plan to ensure 24/7 coverage of the Project while reducing risk by providing coverage of the Project from [redacted] locations.
- The Respondent designated Field Operations Leader who will be responsible for leading the teams that maintain the transmission line equipment, and for ensuring the safe and reliable operation of the Project. Brief resumes provided.
- Key responsibilities, minimum qualifications requirement, and experience for the maintenance Field Operations team and System Operations positions along with resumes described in detail.
- A dedicated training manager is assigned to the Project.
- Respondent also provided the following in detail:
    - Training program including the core training items of the program,
    - Nuclear plant coordination training
    - NERC training,
    - Safety training related to all work activities.
    - Contractor training
    - Hiring practice and procedures
    - Transmission line crew training
    - Vegetation management training

3A.6) Maintenance Plans

- The Respondent provided the following:
  - A Project specific preventive and predictive maintenance plan.
    - The Project's maintenance plan includes a variety of tasks with the goal of predicting the future trend of equipment condition. The plan includes inspections while the equipment is in service. The principles of statistical process control and risk analysis applied to determine at what point in the future maintenance activities will be appropriate. The results are fed into the Asset Management Program (AMP) and can trigger the following: changes to scheduling, task frequency adjustment, or a new work order to address non-normal condition responses.
  - Financial strategy to address catastrophes provided (checked -yes)).
  - Vegetation Management plan to address NERC FAC-003 compliance and Environmental obligations.
  - Financial Strategy for Maintenance Activities and to address catastrophes.
  - Line Equipment Asset Health Review

3A.7) Specialized Maintenance Equipment and Spare Parts

- The Respondent's consultant conducted the Project specific Transmission Line Spares Stock Analysis to review the line configuration data and evaluate the sag/tension criteria for all sag sections. [redacted]
- The proposal includes a detailed list of material and breakdown of hardware, conductor, poles as well as other spares to cover [redacted]
- The Respondent indicated that its transmission line spares strategy includes separating the storage location of its line spares from the Project locations to reduce the risk of both locations being impacted by the same severe event. However, the line structures hardware and conductor will be stored at a location which is an [redacted] from the proposed Project. This timeline is longer than the time provided by other Respondents.
- The plan includes and describes the Project's specialized maintenance equipment tools.
- Lacks maintenance plan for specialized equipment.

3A.8) Maintenance Performance/Expertise

- Respondent provided details of experience with lines in [redacted] for facilities up to 345kV. Also, provided the reliability performance for each line relating to maintenance and operations for similar projects over the last five years.
- Respondent indicated, with support from its affiliates, it has a wealth of experience in transmission and substation siting, design, construction, operations and maintenance, and financing -- including a substantial amount of experience for EHV transmission and substation projects.
- The restoration performance of the [redacted] 345 kV transmission system following recovery from severe weather events (tornadoes) has been 99.99%+.

[redacted]

3A.9) NERC Compliance-Process/History

- Respondent will complete the NERC registrations and the associated requirements specific to the Wolf Creek–Blackberry 345 kV project. Also, upon award of this Project, Respondent will integrate with its internal NERC reliability compliance programs, processes and controls to assure compliance with NERC reliability standards for which Transmission Owners are responsible.
- A copy of the NERC compliance manual included. Internal Compliance Program: Proponent will follow the Parent's documented NERC Reliability Standards Internal Compliance Program (ICP). The [redacted] has responsibility for the internal oversight of compliance with NERC standards.
- Both [redacted] and its Internal Audit (IA) department report through the Senior Vice President of Internal Audit and Compliance, which demonstrates the commitment of the senior management for NERC compliance.
- In preparation for establishing operations for the Project, Respondent team performed an assessment of its existing processes, procedures, tools, training, and personnel that will allow it to perform the operations function of a TO as well as a TOP for the Project.
- Respondent will also have in place vegetation management plans to assure compliance with NERC FAC-003 requirements, and other Proponent processes and procedures assure compliance with the remaining Applicable Reliability Criteria.
- Specific to Wolf Creek–Blackberry, over thirty NERC Reliability Standards compliance training modules have been created and published.
- The proposal lacks the history/recent NERC reliability audit experience.

3A.10) Internal and Contractor Safety Program

- The proposal includes voluminous documentation for internal safety programs specific to this project detailing existing safety programs and past performance, safety training and certification programs. The proposal also includes various attachments to this Proposal that include examples and further explain processes.
- Respondent indicated that its strong safety program has [redacted] safety culture. The safety program, which leverages OSHA's Voluntary Protection Program (VPP), has enabled its T&D function to reach 1st Quartile OSHA and DART rate performance.
- The Proposal includes Process Control Manual, Safety Management Plan and Energy Safety Performance Metrics to further elaborate its safety program.
- The safety program ensures that all contractors, subcontractors, vendors, and suppliers are aware of and comply with the relevant safety requirements, as well as any applicable safety regulations related to the execution of O&M work.
- The safety program also ensures that all appropriate partners have and comply with the "Contractor Safety Requirements Policy", a copy of which is included as part of the Proposal.
- The Proposal includes employee safety training and a list of certification courses.

3A.11) Contractor Safety Program

- The Proposal includes the safety manual of the main support contractor.
- The proposal also includes primary contractor's TCIR & DART data for the last [redacted] provided, which shows a downward trend.

3A.12) Safety Performance Record

- The proposal includes documentation detailing safety plans for similar projects and the past performance of such safety programs.
- The proposal includes Transmission safety records, such as Total Case Incident Rate (TCIR), Days Away Restricted or Transferred (DART) Rates, and Experience Modification Rate (EMR) for the last [redacted]. Respondent indicated [redacted].
- Historical safety performance rates for similar 345 kV Line Design - [redacted] which is excellent.
- Switching errors were zero for the last five years except for two in 2018.

Proposals D and E

Proposals D and E provided relatively less detail information.

3A.1) Control Center Operations

- The Project will be integrated in its Parent company's control center operation located in [redacted] The primary and the secondary control centers are [redacted] miles apart. [redacted]
- Agreement with control center entity not provided to assess this criterion.
- Organization chart and resumes not provided to assess this criterion.
- A total of 23 Operations employees support continued operation of its transmission system, including 10 system operators with an average of 8 years' operating experience, 6 operations supervisors with an average of 12 years' operating experience, 3 outage coordinators with an average of 18 years' experience, 2 operations planners with an average of 16 years' experience, 1 supervising engineer of operations planning and outage coordination with 17 years of experience and a department manager with 21 years of utility experience (10 years in operations).
- Project's integration plan into the control center not provided. Project's system control center operations program details such as switching and outage coordination, real-time monitoring tools including real-time visualization capability not provided to assess this criterion.
- Historical performance of the primary and backup control center, especially during severe weather conditions not provided to assess this criterion.
- Operators' switching success rates Transmission Operations has executed [redacted] since 2012, with an overall switching accuracy of 99.82%.
- Recent NERC TOP audit experience not provided to assess this criterion.

3A.2) Storm/Outage and Emergency Response Plan

- Extensive experience and expertise in quickly and safely responding to unplanned outages due to storm damage.
- Financial strategy to address catastrophes not provided to assess this criterion.
- Major restoration experience within the last three years included only 138 kV response but not for 345 kV facilities similar to this Project.
- Preparation for major storms by utilizing advanced weather forecast tools.
- Respondent also uses a Fault Analysis and Lightning Location tools/software to detect lightning strikes to help determine the cause of lightning-related outages.
- Respondent has a detailed, repeatable process for responding to unplanned outages including a procedure for investigating and evaluating unplanned outages.
- Response time for sustained outage is slower as compared to corresponding information provided by other Respondents.

3A.3) Reliability Metrics

- Respondent is familiar with the SPP outage process and other operational protocols.
- Project specific plan for reliability provided to assess this criterion.
- Transmission Operations has executed [redacted] since 2012, with an overall switching accuracy of 99.82%

- Sustained and force outage data provided for assessment.
- Historical forced line outage data analyzed in detail to identify trends to predict and prevent future unplanned outages. Similarly, the Transmission Line Reliability Team will review all unplanned outages on the Wolf Creek Blackberry 345 kV line in detail to identify trends that it uses to predict and prevent future unplanned outages.
- Experience of coordinating with operations of nuclear power plants.
- Respondent has set the acceptable unplanned outage threshold for the Wolf Creek Blackberry 345 kV line [redacted].
- Long term strategic goal is to perform in the top quartile of our peers per the NATF benchmarking metrics.

3A.4) Restoration Experience/Performance

- Decades of experience in responding to transmission line related emergencies [redacted]
- Experience Example of recent 138 kV line restoration provided but not for 345 kV.

3A.5) Maintenance Staffing/Training

- Brief description of Transmission Line maintenance staff regarding years of service and background.
- Engineering department utilizes a formal training model of [redacted]. Brief description of vegetation maintenance staff regarding years of service and background provided to assess this criterion. The vegetation management team has completed [redacted] with outstanding results of zero Potential Non-Compliance issues or Open Enforcement Actions. New vegetation supervisors follow a multi-week training including review of the FAC-003 standard.
- Maintenance staffing specific to this Project such as organization chart, responsibilities, staffing, assignment, experience, resumes, etc., not described.
- Training for maintenance staff and vegetation management staff described very briefly.

3A.6) Maintenance Plans

- A robust preventative maintenance timeline for transmission line inspections provided and described in detail, which includes aerial, ground and other methods of inspection.
- Respondent proposes to assign all maintenance issues found during inspections of the Wolf Creek-Blackberry 345 kV line a priority ranking and develop a risk profile for the line.
- Transmission line repairs priority ranking system described in detail
- Staffing level, organization chart and resumes not provided to assess this criterion.
- Vegetation management described in detail. Vegetation priority ranking to fix vegetation problems.
- Frequency of inspections slower than other Respondents

3A.7) Specialized Maintenance Equipment and Spare Parts

- Respondent will maintain necessary volumes of spare materials to restore the Wolf Creek-Blackberry 345 kV line within [redacted] of an incident.
- The specialized equipment and other resources are dispersed through Respondent's service territories [redacted] Response time higher than the response time proposed by other Respondents.

- Respondent's alliance contractors have headquarters in the [redacted] region that can arrive at the Wolf Creek-Blackberry 345 kV line within [redacted] of dispatch.
- Respondent to keep spares for [redacted] of the line failures.
  Spare inventory includes all items that will be stocked to support restoration activities for the Project provided to assess this criterion.
- Respondent has partnered with a nearby Cooperative member to store material [redacted] of the Project needed to quickly restore single-component failures.
- Specialized equipment plan and inventory needed to restore the damaged part of this Project as soon as possible not provided to assess the capability of the Respondent for this criterion.
- Maintenance of the specialized equipment not described.

3A.8) Maintenance Performance/Expertise

- The information provided for this criterion includes quality assurance during and after construction, which is irrelevant for the Operations category. The associated attachments provide information that is irrelevant to evaluate this criterion.
- Maintenance performance and expertise information requested for the criterion is not provided to assess the ability of the Respondent for this criterion.
- Vegetation quality assurance plan provided, which is irrelevant for this criterion.
- The following information to evaluate this criterion is not provided to assess the ability of the Respondent for this criterion:
  - Maintenance performance experience, especially with 345 kV lines
  - Reliability performance of 345 kV lines relating to the maintenance and operations for similar projects over the last five years
  - Maintenance organization chart, responsibilities, resumes, expertise
  - Vegetation management organization chart, resumes, expertise, staffing assignment specific to this Project,
  - Maintenance staff training
  - Vegetation management staff training
  - Contractor staffing / organization chart
  - Contractor maintenance training.

3A.9) NERC Compliance-Process/History

- Respondent will use its existing NERC compliance internal processes and controls for the Project to comply with the applicable NERC requirements.
- Respondent will register the line in [redacted] for all necessary reliability functions with NERC and [redacted] required for the Wolf Creek-Blackberry 345 kV transmission line.
- Respondent's Compliance team has eight full time employees supporting Respondent functions including Transmission and generation with four full time members with over 50 years of experience in transmission engineering, operation, and maintenance functions.
- Recent NERC reliability audit history not provided to assess this criterion.
- Details of the NERC compliance plan including corporate hierarchy, senior executive reporting, internal audit function etc., not provided to assess this criterion.
- Vegetation management associated with NERC compliance [redacted] and vegetation management strategy covered in detail.

3A.10) Internal and Contractor Safety Program

- General internal and contractor safety program provided in detail.
- Construction contractor safety program and requirements described in detail.
- Maintenance and repair contractor safety requirements specific to this project are lacking.
- Safety audit dashboard mentioned but no examples or history.

3A.11) Contractor Safety Program

- General internal and contractor safety program described in detail.

3A.12) Safety Performance Record

- Internal Safety Metrics and Safety Metrics for Contractors provided to assess this criterion.
- Days Away Restricted Transferred (DART) Rate provided for the [redacted] years.
- DART rate going down every year indicating better safety.
- DART rate higher than other respondents

Proposal F

This Proposal provided very detailed information for evaluation [redacted]

3A.1) Control Center Operations

- Designated Entity will operate and integrate the Wolf Creek-Blackberry 345 kV line through the primary control centers and backup control centers, [redacted] fully operational.
- Respondent indicated that by using Designated Entity to provide operations and facilitate maintenance services, Respondent would have the advantage of integrating the operations of the project into Designated Entity's existing infrastructure. This capability would be even more valuable because the [redacted]
- [redacted] Both control centers have state of the art real time tools and ability to analyze over [redacted]
- Enhanced situational awareness capabilities including weather and truck location information.
- Virtualized environment in the control center for real time situational awareness.
- Designated Entity/Respondent agreement provided to assess this criterion.
- Relevant control center operational experience provided to assess this criterion.
- NERC Audit affirmed the Designated Entity as [redacted].
- Over the last 11 years, the transmission system operators have achieved a 99.9% switching step success rate, and successfully complete nearly [redacted] each year.
- The [redacted] employs 17 dedicated employees and 8 NERC-certified and qualified operators. These TSOs are the personnel that will directly monitor and operate the Wolf Creek-Blackberry 345 kV line.
- The [redacted] operators employ a variety of real-time tools for continuous monitoring and evaluation of the Designated Entity transmission system: such as, EMS/SCADA, State estimation, Real-time contingency analysis, Supplemental visualization and Situational awareness applications.

[redacted]

- Organization chart of the [redacted] along with brief resumes provided to assess this criterion.
- [redacted] staff who will be the primary support for the new line have a combined 278 years of utility experience, in the range of 3 to 36 years, with an average of 7 years of TSO experience per person.

3A.2) Storm/Outage and Emergency Response Plan

- Preventive measures: transmission control center contingency plans in place; training is a core component to the success; Blackstart drills annually; advanced weather forecast.
- Project specific planned outage response program described in detail except for [redacted]
- Designated Entity always has at least 2, 8-man transmission line contract crews [redacted]

- Existing resource locations featuring [redacted] service centers and material hubs within [redacted] These resources may be supplemented by the primary contractor with resources [redacted].
- A rigorous and proven predictive and preventive maintenance program with Track record of performance of system emergency response capabilities.
- Material and spare hub about [redacted] from the line.
- Local response team can respond with [redacted].
- Project specific planned and forced outage response plan including major/widespread outage emergency plan described in detail [redacted]
- The [redacted] supporting the Wolf Creek-Blackberry Project shares dedication to delivering rapid and superior emergency response as demonstrated by achievements and experience, such as over 140 years of combined experience; 12,500+ hours of storm response in 2020; and 478 miles of emergency aerial patrols in 2020.
- Respondent also will have access to Designated Entity's external meteorological [redacted] weather forecast program, which provides daily updates that will alert the crew of any weather threats that can cause widespread power outages.
- A list of local emergency response key personnel along with brief resumes provided to assess this criterion.

[redacted]

- Financial strategy provided to address catastrophes.

3A.3) Reliability Metrics

- History of record of safe operation and line availability described in detail [redacted]
- To ensure accurate monitoring of the Wolf Creek-Blackberry 345 kV line, Designated Entity will add displays to the Designated Entity EMS system for the new line and devices. Data from the AECI Blackberry substation will be coordinated.

[redacted]

- Key momentary and sustained outage metrics for each of the past 5 years, along with our 5-year average [redacted]

[redacted] The 5-year outage average for 345 kV single circuit lines shows less than 1 outage per year per circuit. [redacted]

- All planned line and substation switching will be completed in accordance with the well-established and known procedures in the existing Designated Entity System using the Operating Manual, a copy of which is provided, as part of the Proposal.

3A.4) Restoration Experience/Performance

- Past restoration experience for projects similar in size and scope in the last five years. Restoration associated [redacted] not provided to assess this criterion.
- [redacted] tool applied for weather forecast.

[redacted]

- Experience and statistics on recent major storms and restoration for similar 345 kV lines provided to assess this criterion.

3A.5) Maintenance Staffing/Training

- Respondent indicated that its personnel will provide operations and maintenance services to the Wolf Creek-Blackberry line with [redacted]
- Maintenance training and expertise to deal with the [redacted] not addressed.
- The organization chart for the Transmission C&M department along with specialist capabilities provided to assess this criterion.
- Qualifications and experience of the anticipated staff specific to the maintenance of this project provided in very detail and designated key personnel for this Project with brief resumes; Makeup of the maintenance Crew Staffing; maintenance crew equipment; training, staffing, and qualifications for internal and contractor. The proposal claims that one of the many reasons why for [redacted], on average, experienced less than 1 outage per year.
- Transmission vegetation management related maintenance staffing and training specific to this Project provided in detail, including names and their resumes.
- Transmission vegetation management - Designated Entity has a dedicated team of 9 employees based out of [redacted] who manage vegetation management work and help protect transmission line assets. The designated qualified individuals have 30 years of combined vegetation management experience who will provide vegetation management strategy and services to the Wolf Creek-Blackberry 345 kV line.
- Transmission Line Engineering organization that will support this Project, as needed, has over 50 years of combined experience and four Professional Engineering licenses in the state of Missouri.
- Any special considerations for special expertise required for maintenance and training associated with the [redacted] not addressed.

3A.6) Maintenance Plans

- Preventive and predictive maintenance plans specific to this project including description for transmission lines maintenance programs provided in detail. [redacted]
- The Respondent will leverage the expertise of Designated Entity Large Construction, Construction & Maintenance (C&M), and Vegetation Management to plan and implement industry-leading predictive and preventive maintenance of the Wolf Creek-Blackberry 345 kV line in accordance with the guidelines outlined in the proposal, consistent with good utility practice, including the financial strategy for maintenance.
- A robust preventative maintenance timeline for transmission line inspections provided and described in detail, which includes aerial, ground, and other methods.
- Rigorous vegetation maintenance plan to keep the ROW clear and comply with NERC requirements.
- After successful construction and commissioning of this Project completion, [redacted] will be put in place to ensure that Project assets are operating to the highest possible level.

3A.7) Specialized Maintenance Equipment and Spare Parts

- A list of maintenance equipment specifically required for this project and information regarding its use provided to assess this criterion.
- Replacement capabilities, i.e., "spare parts" that will be maintained for this project and planned sharing agreements with other entities.
- List of transmission class equipment currently being used on transmission maintenance work [redacted] Approximately 1/4 of this transmission maintenance contractor equipment is working within 50 miles of the proposed line.
- Respondent will store spares for [redacted] of line replacement including conductors, shield wire, fiber optics reels, insulators hardware, and poles. Inventory of all spares provided except for spares associated with the double circuit tower segment of the lines.
- A list of specialized tools and equipment owned by the primary contractor, which will be used to provide preventive maintenance for the Wolf Creek-Blackberry 345 kV transmission line.
- The spares are located at [redacted].
- Respondent estimates that it can replace [redacted] completely destroyed structures plus [redacted] minimally damaged structures and return the Project line to service within [redacted], at most, following damage assessment, which is far less than the estimates provided by other Respondents.

3A.8) Maintenance Performance/Expertise

- On average, within the [redacted], Designated Entity experienced less than 1 outage per year, [redacted]
- Maintenance experience and itemize relevant past performance in the last five years provided for assessment of this criterion. This [redacted] with 345 kV transmission line maintenance.
- Designated Entity, currently maintains [redacted]
- Vegetation management work completed since 2010 [redacted] is described in detail.
- Examples of recent restoration events provided to assess this criterion [redacted]
- Contractor experience/expertise not provided to assess this criterion.

3A.9) NERC Compliance-Process/History

- Respondent is already registered in [redacted] and the NERC compliance obligations will be performed by Designated Entity as a NERC compliance registered TO and Transmission Planner (TP).
- Designated Entity is already fully qualified to address and respond to the complete portfolio of NERC standards and requirements on behalf of Respondent in the [redacted], regarding TO and TP applicability.
- Respondent has created a [redacted] composed of compliance professionals from its parent company and Designated Entity to ensure peer review and continuity for all new and existing operating assets. This same committee also will have oversight of this Project.
- [redacted] provided as part of the Proposal, which includes governance, organization chart, comprehensive matrix of applicable regulatory requirements that identifies company personnel responsible for compliance with these requirements.

- Processes for auditing, reporting violations and ensuring remediation efforts when appropriate were described in detail.
- Mandated training to enable employees to comply with the requirements and training.
- Designated Entity has 17 full-time employees dedicated to FERC and NERC compliance, 5 of which are dedicated to assurance monitoring. These employees have a broad range of experience and backgrounds to guide Designated Entity's compliance with applicable FERC and NERC regulations.
- Detailed specific plan for Wolf Creek-Blackberry facility integration into NERC compliance.
- [redacted]
- Vegetation management and associated training described as part of the NERC requirement FAC 003.
- Recent NERC reliability audit experience provided to assess this criterion.

3A.10) Internal and Contractor Safety Program

- Internal safety programs detailing existing safety and certification programs and past performance described in detail.
- The Designated Entity Safety Program is a multifaceted program that addresses safety at all organizational levels.
- A comprehensive Contractor Safety Program (CSP) covering monthly field safety meetings, safety monitoring, auditing, tracking, and trending described in detail.
- The Designated Entity Safety Organization has 52 individuals dedicated to providing safety and health strategy, training, processes, policies, and best practices across the Designated Entity system.
- Designated Entity Safety organization chart provided with resumes.
- The Proposal includes documentation detailing safety plans for similar projects and the past performance for such safety programs.
- Contractor's safety performance statistics for last two years including OSHA, DART, and EMR provided to assess this criterion. The designated contractor has received [redacted] Safety Achievements awards.

3A.11) Contractor Safety Program

- The Proposal described and provided documentation for any contractors that will be used for this project detailing existing safety programs and past performance, safety training and certification programs described in detail.
- Contractor's Safety Performance including DART and EMR for the last two years provided to assess this criterion.
- Respondent will leverage Designated Entity's rigorous [redacted] contractor safety qualification process for the Wolf Creek-Blackberry 345 kV Project. [redacted] is a contractor management program that supports its safe contractor hiring practices.

3A.12) Safety Performance Record

- Documentation detailing safety plans for similar projects and the past performance for such safety programs described and provided including two years of safety performance statistics. The DART rate is higher than other respondents while the EMR rate [redacted], which is good.

Proposal G

This Proposal provided very detail information for evaluation.

3A.1) Control Center Operations

- Designated Entity will operate and integrate the Wolf Creek-Blackberry 345 kV line through the primary control centers and backup control centers, which are [redacted] apart and fully operational.
- Respondent indicated that by using Designated Entity to provide operations and facilitate maintenance services, Respondent would have the advantage of integrating the operations of the project into Designated Entity's existing infrastructure. This capability would be even more valuable because the [redacted]
- Both control centers have state of the art real time tools and ability to analyze over [redacted]
- Enhanced situational awareness capabilities including weather and truck location information.
- Virtualized environment in the control center for real time situational awareness.
- Designated Entity/Respondent agreement provided to assess this criterion.
- Relevant control center operational experience provided to assess this criterion.
- NERC Audit affirmed the Designated Entity as [redacted].
- Over the last 11 years, the transmission system operators have achieved a 99.9% switching step success rate, and successfully complete nearly [redacted] each year.
- The [redacted] employs 17 dedicated employees and 8 NERC-certified and qualified operators. These TSOs are the personnel that will directly monitor and operate the Wolf Creek-Blackberry 345 kV line.
- The [redacted] operators employ a variety of real-time tools for continuous monitoring and evaluation of the Designated Entity transmission system: such as, EMS/SCADA, State estimation, Real-time contingency analysis, Supplemental visualization and Situational awareness applications.

[redacted]

- Organization chart of the [redacted] along with brief resumes provided to assess this criterion.
- [redacted] staff who will be the primary support for the new line have a combined 278 years of utility experience, in the range of 3 to 36 years, with an average of 7 years of TSO experience per person.

3A.2) Storm/Outage and Emergency Response Plan

- Preventive measures: transmission control center contingency plans in place; training is a core component to the success; Blackstart drills annually; advanced weather forecast.
- Project specific planned outage response program described in detail.
- [redacted] collectively [redacted] of the Project location.
- Designated Entity always has at least 2, 8-man transmission line contract crews in the Project area.
- Existing resource locations featuring our service centers and material hubs within [redacted] resources may be supplemented by the primary contractor with resources [redacted]

- A rigorous and proven predictive and preventive maintenance program with Track record of performance of system emergency response capabilities.
- Material and spare hub about [redacted] from the line.
- Local response team can respond with [redacted].
- Project specific planned and forced outage response plan including major/widespread outage emergency plan described in detail.
- The [redacted] supporting the Wolf Creek-Blackberry Project will share a dedication to delivering rapid and superior emergency response as demonstrated by achievements and experience, such as over 140 years of combined experience; 12,500+ hours of storm response in 2020; and 478 miles of emergency aerial patrols in 2020.
- Respondent also will have access to Designated Entity's external meteorological [redacted] weather forecast program, which provides daily updates that will alert the crew of any weather threats that can cause widespread power outages.
- A list of local emergency response key personnel along with brief resumes provided to assess this criterion.

[redacted]

- Financial strategy provided to address catastrophes.

3A.3) Reliability Metrics

- History of record of safe operation and line availability described in detail.
- To ensure accurate monitoring of the Wolf Creek-Blackberry 345 kV line, Designated Entity will add displays to the Designated Entity EMS system for the new line and devices. Data from the AECI Blackberry substation will be coordinated.

[redacted]

- Key momentary and sustained outage metrics for each of the past 5 years, along with our 5-year average provided to assess this criterion.
- The 5-year average shows less than 1 outage per year per circuit. [redacted]
- All planned line and substation switching will be completed in accordance with the well-established and known procedures in the existing Designated Entity System using the Operating Manual, a copy of which is provided, as part of the Proposal.

3A.4) Restoration Experience/Performance

- Past restoration experience for projects similar in size and scope in the last five years.
- [redacted] tool applied for weather forecasts.

[redacted]

- Experience and statistics on recent major storms and restoration for similar 345 kV lines provided to assess this criterion.

3A.5) Maintenance Staffing/Training

- Respondent indicated that its personnel will provide operations and maintenance services to the Wolf Creek-Blackberry line with [redacted]
- The organization chart for the Transmission C&M department along with specialist capabilities provided to assess this criterion.
- Qualifications and experience of the anticipated staff specific to the maintenance of this project provided in very detail and designated key personnel for this Project with brief resumes; Makeup of the maintenance Crew Staffing; maintenance Crew Equipment; training, staffing, and qualifications for internal and contractor. The proposal claims that one of the many reasons why for [redacted] have, on average, experienced less than 1 outage per year.
- Transmission vegetation management related maintenance staffing and training specific to this Project provided in detail, including names and their resumes.
- Transmission vegetation management - Designated Entity has a dedicated team of 9 employees [redacted] who manage vegetation management work and help protect transmission line assets. The designated qualified individuals have 30 years of combined vegetation management experience who will provide vegetation management strategy and services to the Wolf Creek-Blackberry 345 kV line.
- Transmission Line Engineering organization that will support this Project, as needed, has over 50 years of combined experience and four Professional Engineering licenses [redacted]

3A.6) Maintenance Plans

- Preventive and predictive maintenance plans specific to this project including description for transmission lines maintenance programs provided in detail.
- The Respondent will leverage the expertise [redacted] in accordance with the guidelines outlined in the proposal, consistent with good utility practice, including the financial strategy for maintenance.
- A robust preventative maintenance timeline for transmission line inspections provided and described in detail, which includes aerial, ground and other methods.
- Rigorous vegetation maintenance plan to keep the ROW clear and comply with NERC requirements.
- After successful construction and commissioning of this Project completion, a [redacted] will be put in place to ensure that Project assets are operating to the highest possible level.

3A.7) Specialized Maintenance Equipment and Spare Parts

- A list of maintenance equipment specifically required for this project and information regarding its use provided to assess this criterion.
- Replacement capabilities, i.e., "spare parts" that will be maintained for this project and planned sharing agreements with other entities.
- List of transmission class equipment currently being used on transmission maintenance work [redacted] Approximately 1/4 of this transmission maintenance contractor equipment is working within 50 miles of the proposed line.

- Respondent will store spares for [redacted] of line replacement including conductors, shield wire, fiber optics reels, insulators hardware, and poles. Inventory of all spares provided to assess this criterion.
- A list of specialized tools and equipment owned by the primary contractor, which will be used to provide preventive maintenance for the Wolf Creek-Blackberry 345 kV transmission line.
- The spares are located at [redacted].
- Respondent estimates that it can replace [redacted] completely destroyed structures plus [redacted] minimally damaged structures and return the Project line to service within [redacted], at most, following damage assessment, which is far less than the estimates provided by other Respondents.

3A.8) Maintenance Performance/Expertise

- On average, within the [redacted], Designated Entity experienced less than [redacted] outage per year, [redacted]
- Maintenance experience and itemize relevant past performance in the last five years provided for assessment of this criterion. [redacted] direct experience with 345 kV transmission line maintenance.
- Designated Entity, currently maintains [redacted]
- Vegetation management work completed since 2010 [redacted] is described in detail. .
- Examples of recent restoration events provided to assess this criterion.
- Contractor experience/expertise not provided to assess this criterion.

3A.9) NERC Compliance-Process/History

- Respondent is already registered in [redacted] and the NERC compliance obligations will be performed by Designated Entity as a NERC compliance registered TO and Transmission Planner (TP).
- Designated Entity is already fully qualified to address and respond to the complete portfolio of NERC standards and requirements on behalf of Respondent in the [redacted], regarding TO and TP applicability.
- Respondent has created a [redacted] comprised of compliance professionals from its parent company and Designated Entity to ensure peer review and continuity for all new and existing operating assets. This same committee also will have oversight of this Project.
- [redacted] provided as part of the Proposal, which includes governance, organization chart, comprehensive matrix of applicable regulatory requirements that identifies company personnel responsible for compliance with these requirements.
- Processes for auditing, reporting violations and ensuring remediation efforts when appropriate is described in detail.
- Mandated training to enable employees to comply with the requirements and training.
- Designated Entity has 17 full-time employees dedicated to FERC and NERC compliance, 5 of which are dedicated to assurance monitoring. These employees have a broad range of experience and backgrounds to guide Designated Entity's compliance with applicable FERC and NERC regulations.
- Detailed specific plan for Wolf creek-blackberry facility integration into NERC compliance.

[redacted]

- Vegetation management and associated training described as part of the NERC requirement FAC 003.
- Recent NERC reliability audit experience provided to assess this criterion.

3A.10) Internal and Contractor Safety Program

- Internal safety programs detailing existing safety and certification programs and past performance described in detail.
- The Designated Entity Safety Program is a multifaceted program that addresses safety at all organizational levels.
- A comprehensive Contractor Safety Program (CSP) covering monthly field safety meetings, safety monitoring, auditing, tracking, and trending described in detail.
- The Designated Entity Safety Organization has 52 individuals dedicated to providing safety and health strategy, training, processes, policies, and best practices across the Designated Entity system.
- Designated Entity Safety organization chart provided with resumes.
- The Proposal includes documentation detailing safety plans for similar projects and the past performance for such safety programs.
- Contractor's safety performance statistics for last two years including OSHA, DART, and EMR provided to assess this criterion. The designated contractor has received [redacted] Safety Achievements awards.

3A.11) Contractor Safety Program

- The Proposal described and provided documentation for any contractors that will be used for this project detailing existing safety programs and past performance, safety training and certification programs described in detail.
- Contractor's Safety Performance including DART and EMR for the last two years provided to assess this criterion.
- Respondent will leverage Designated Entity's rigorous [redacted] contractor safety qualification process for the Wolf Creek-Blackberry 345 kV Project. [redacted] is a contractor management program that supports its safe contractor hiring practices.

3A.12) Safety Performance Record

- Documentation detailing safety plans for similar projects and the past performance for such safety programs described including two years of safety performance statistics. The DART rate is higher than other respondents while the EMR rate [redacted], which is good.

The following Tables list the DART and EMR rates provided by all/some Respondents.

DART Rate Comparison For All Proposals.

OSHA Recordable Incident Rate (Incident Rate) and Days Away Restricted Transferred (DART) Rate												
Proposal	2015		2016		2017		2018		2019		2020	
	Incident Rate	DART Rate	Incident Rate	DART Rate	Incident Rate	DART Rate	Incident Rate	DART Rate	Incident Rate	DART Rate	Incident Rate	DART Rate
A	[redacted]											
B												
C												
D												
E												
F												
G												

EMR Comparison For All Proposals

Experience Modification Rate (EMR)						
Proposal	2015	2016	2017	2018	2019	2020
A	[redacted]					
B						
C						
D						
E						
F						
G						

IV: Rate Analysis

This Appendix to the Rate Analysis Section is organized into the following parts:

- Part 1: Executive Summary
- Part 2: The establishment of the evaluation criteria.
- Part 3: Scoring methodologies, proposal scores and supporting IEP analysis for scoring the following criteria:
  - RRE
  - PVRR
  - Other Attachment Y criteria
- Part 4: The final results of the proposal evaluations

Part 1: Executive Summary

The IEP evaluator has divided the analysis into 4 sections in order to document the process the IEP utilized in scoring the Rate Analysis section. The IEP evaluator utilized the scoring criteria as outlined in this Appendix. The IEP scored the pre-established criteria of RRE, PVRR and other Attachment Y factors. This IEP evaluator utilized the information filed in the bid proposals to develop tables for further analysis of the cost input components for the RRE and PVRR criteria. The IEP evaluator in this Appendix outlines their evaluation and scoring criteria, the scoring results as well as, providing a descriptions of the analysis of the information reviewed in developing the scores by criteria.

Part 2: The Establishment of the Evaluation Criteria

The IEP met prior to the submission of the bid proposals and established their evaluation methodology and criteria. These criteria were released prior to the deadline for the submission of proposals.

Section 4: Rates (Cost to Customer) 225 Pts *Measures an RFP Respondent's and, if applicable, a CU Participant's cost to construct, own, operate, and maintain the Competitive Upgrade over a 40-year period*	**Sub-criteria**	**Weight**	**Total Pts (200)**
4a) Estimated Total Cost of Project (RFP Response Estimate - RRE)		45%	101.25
4b) Present Value Revenue Requirement (PVRR)	4b.1) Financing Costs		
	4b.2) FERC Incentives		
	4b.3) Revenue requirements		
	4b.4) Lifetime Cost of the Project to Customers		
	4b.5 Return on Equity		
	Sub-Total Criteria Pts	45%	101.25
4c) Other Attachment Y Factors	4c.1) The quantitative cost impact of material on hand, assets on hand, rights-of-way ownership, control, or acquisition		
	4c.2) Cost Certainty guarantee		
	4c.3) Other Comments		
	Sub-Total Criteria Pts	10%	22.5
	Scoring Category Total	**100%**	**225**

Part 3: Scoring methodologies and proposal evaluation results for the RRE criteria

RRE Scoring Methodologies:

As discussed in the evaluation section, points for the RRE (cost to construct) were awarded based on the lowest cost numbers (i.e., the lower the cost numbers for RRE the higher the amount of points were awarded. In addition, the scoring for the RRE criteria was also conditioned on the cost proposal meeting the requirements of the other IEP evaluation categories.

In addition, the IEP evaluator determined that each Respondent did meet the filing requirements for the RRE criteria as outlined in the RFP and therefore would receive 50.625 points for meeting this criteria.

Scoring Results for the RRE Criteria

As stated in the scoring methodology narrative section, the scoring and awarding of points for the RRE category were based on a two-step process. The table below illustrate the two-step process for scoring each proposal for the RRE criterion.

Scoring Methodology for RRE Criterion

	A	B	C	D	E	F
Line No.	Bid	Lowest to Highest Bid RRE	Perccent of lowest RRE	50.625 pts Times Percent of Lowest RRE	Minmum RRE Score of 50.625 pts	Total RRE Point Score (ColumnD+E=F)
1	C	$ 85,168,938.30	100.00%	50.625	50.625	101.25
2	A	$ 116,554,150.73	73.07%	36.99	50.625	87.62
3	B	$ 121,105,590.19	70.33%	35.60	50.625	86.23
4	F	$ 126,505,598.17	67.32%	34.08	50.625	84.71
5	D	$ 143,802,827.00	59.23%	29.98	50.625	80.61
6	G	$ 144,924,580.12	58.77%	29.75	50.625	80.38
7	E	$ 151,156,536.00	56.34%	28.52	50.625	79.15

Supporting IEP Analysis for Scoring the RRE Criteria

IEP Analysis of RFP Response Estimate (RRE)

Each Proposal's response to its Estimated Total Cost of the Project (RRE) was compiled by the IEP evaluator from each proposal's submission found in tab 2B cell C36 of the Response Form Excel Workbook. In this section of the report the IEP evaluator listed each proposal's RRE along with several tables that compared the dollar value of each proposal's RRE to the other proposal's RRE for evaluation and scoring purposes.

To illustrate the dollar difference from the lowest to the highest RRE, the evaluator compiled the table below to illustrate the dollar and percentage differences between the bid proposals.

Table 4A.1.2
RRE Cost Summary
Wolf Creek - Blackberry RFP
4A.1-1- Response Form Excel Workbook -Tab 2B - RRE Cost Summary
Dollar Difference From Lowest to Highest RRE

Line No.	Bidder	Total RRE Cost Estimate:	Dollar Difference From Lowest to Highest RRE	Percentage Difference
1	C	$ 85,168,938.30	$0	0.00%
2	A	$ 116,554,150.73	$31,385,212	26.93%
2	B	$ 121,105,590.19	$35,936,652	29.67%
4	F	$ 126,505,598.17	$41,336,660	32.68%
5	D	$ 143,802,827.00	$58,633,889	40.77%
6	G	$ 144,924,580.12	$59,755,642	41.23%
7	E	$ 151,156,536.00	$65,987,598	43.66%

As stated in the RFP and bid proposals, the details for the basis of calculating the RRE were from the cost estimates contained in the Excel Response Form Workbook Tabs 2a and 2b.

Tab 2A is "Itemized Cost of Transmission line Materials". Tab 2A includes the following line items:

- Conductors
- Dead Ends
- Tangents
- Storm Structures
- Steel (lbs.)
- Wood (lbs.)
- Foundations (installed) (cubic yards)
- Tap Switch
- Shield Wire
- Permitting
- Environmental
- Other – Itemize
- Access Road
- Demolition / Disposal Costs
- Transmission Line Material Subtotal
- Sales Tax; and
- Transmission Line Material Total (cell 43D). [The Transmission Line Material Total (cell 43D) is included in Tab2 B cell 7C]

Tab 2B is the "RRE Cost Summary"

Tab 2B includes the following line items: Transmission Line #1 – Costs. This category includes the line items of Engineering Labor; Construction Labor; Right-of-Way Clearing and Real Estate Acquisition; and Material (the material number is from Tab 2A.

Tab 2B also includes a category labeled Summary Info. Within this category are the following line items: Transmission Line Total; AFUDC (If amount given, CWIP should be "No"); Contingency; Overhead; Risk Management; Security Measures; Regulatory/Legal; Other - Misc. Expenses (Describe below).

When the numbers in Tab 2B are totaled they result in the computation of the Total RRE Cost Estimate.

Since the cost estimates in Tabs 2A and 2B have a direct impact on the calculation of the RRE, the IEP evaluator performed an analysis of the information submitted in these tabs by the Respondents. This analysis is discussed below.

<u>IEP Analysis of Total Estimate RRE Proposal Submissions</u>

<u>Analysis of Proposal A's Response</u>

- Proposal A's RRE is $116,554,151 (second lowest RRE). Proposal A's RRE is $31,385,212 higher than the lowest RRE of Proposal C's which is $85,168,938.

[redacted]

[redacted]

[redacted]

[redacted]

- Proposal A submitted a well-developed and documented proposal which identified a cost estimate based on Project specific designs and implementation plans. In addition to the cost of materials the Proposal cost estimates for labor, equipment, and other non-materials were developed based on Project specific information contained in the implementation plans completed by Proposal A and its team of contractors and firms. (see Section B1.4). A breakdown and description of these costs are included in Table 4A.1-16 through Table 4A.1-26.

<u>Analysis of Proposal B's Response</u>

- Proposal B's RRE is $121,105,590 (third lowest RRE). Proposal B's RRE is $35,936,652 higher than the lowest RRE of Proposal C's which is $85,168,938.

[redacted]

- Proposal B submitted an excellent detailed cost estimate based on a team of experts familiar with the area of operations in order to complete the following tasks:
    - Detailed routing studies to identify a realistic route alternative in support of obtaining the necessary permits and right-of-way considering key drivers;
    - A permitting plan in consultation with permitting agencies;
    - Identification of permanent right-of-way requirements, potentially affected landowners and parcels, and anticipated land values supported by a market study;
    - A detailed access plan that identifies access need to every structure and all temporary construction land rights;
    - A conductor study considering capital costs and costs during operations (e.g., losses);
    - A structure optimization study to identify a structure design that is cost effective with a low risk to implementation;
    - A geotechnical study in combination with local knowledge and experience to inform anticipated geotechnical conditions and foundation design;
    - Detailed transmission line engineering for the preferred route including designing every structure and foundation with full plan and profile drawings and PLS-CADD models;
    - Identification of all required materials with vendor quotes specific to the Project;
    - Procurement, construction and commissioning execution plans informed by field reconnaissance, right-of-way access plans, detailed engineering and vendor discussions;
    - Detailed construction cost build ups by the contractors that will be performing the work; and
    - A detailed risk assessment for the cost of the Project and implemented strategies to mitigate those risks to inform the appropriate allowance for contingency.

Analysis of Proposal C's Response

- Proposal C's RRE is $85,168,938, which is the lowest RRE of all seven proposals and therefore it is awarded the highest number of points.

[redacted]

[redacted]

- Thorough narrative by Proposal C on its cost proposal. All Proposal C's cost estimates go through a detailed and structured review process. Project Estimators within the Respondents organization review the cost estimates internally with the Manager of Estimating, then with Engineering & Construction Project Management and the Executive Leadership team before estimates are approved for a proposal. [redacted]

Analysis of Proposal D's Response

- Proposal D's RRE is $143,802,827 (fifth lowest RRE). Proposal D's RRE is $58,633,889 higher than the lowest RRE of Proposal C's which is $85,168,938.

[redacted]

- For the purposes of the cost estimate, Proposal D applied an escalation rate of [redacted] for capital/construction costs to arrive at the total RRE referenced in 4A1.1. Proposal D's internal and external estimators each have procurement groups with significant breadth and scale that have worked jointly to reduce the risk of cost escalation over the construction period. The RFP Respondents are confident in the cost estimate using the estimated escalation rate of [redacted] Proposal D provided detailed cost estimates and documents in their Bid proposal for the cost estimate for the total RRE.

Analysis of Proposal E's Response

- Proposal E's RRE is $151,156,536 (seventh-lowest RRE). Proposal E's RRE is $65,987,598 higher than the lowest RRE of Proposal C's which is $85,168,938.

[redacted]

- For the purposes of the cost estimate, Proposal E applied an escalation rate of [redacted] for capital/construction costs to arrive at the total RRE referenced in 4A1.1. Proposal E's internal and external estimators each have procurement groups with significant breadth and scale that have worked jointly to reduce the risk of cost escalation over the construction period. The RFP Respondents are confident in the cost estimate using the estimated escalation rate of [redacted] Proposal E provided detailed cost estimates and documents in their Bid proposal for the cost estimate for the total RRE.

<u>Analysis of Proposal F's Response</u>

- Proposal F's RRE is $126,505,598 (fourth-lowest RRE). Proposal F's RRE is $41,336,660 higher than the lowest RRE of Proposal C's which is $85,168,938.

[redacted]

- In Proposal F's proposal, it states that in order to develop project cost estimates the team worked to establish a [redacted] procurement path for all engineering and right-of-way services, permitting, materials, and line construction including safety management, clearing, access, material management, testing, and commissioning support [redacted]

Analysis of Proposal G's Response

- Proposal G's RRE is $144,924,580 (sixth lowest RRE). Proposal G's RRE is $59,755,642 higher than the lowest RRE of Proposal C's which is $85,168,938.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted] In Proposal G's proposal, it states that in order to develop project cost estimates the team worked to establish a [redacted] procurement path for all engineering and right-of-way services, permitting, materials, and line construction including safety management, clearing, access, material management, testing, and commissioning support. [redacted]

The IEP evaluator also looked to see what the relationship between Proposals are for the dollar amount of materials compared to the other RRE costs in relation to the Total Estimated RRE. The table illustrates those dollar and percentage relationships.

[redacted]

Part 3: Scoring Methodologies, Proposal Scores and Supporting IEP Analysis for Scoring the PVRR Criteria

PVRR Scoring Methodologies:

As discussed in the evaluation section, points for the PVRR (cost to own, operate and maintain the project) were awarded based on the lowest cost numbers (i.e., the lower the cost numbers for PVRR the higher the amount of points were awarded. In addition, the scoring for the PVRR criteria was also conditioned on the cost proposal meeting the requirements of the other IEP evaluation categories.

In addition, the IEP evaluator determined that each Proposal did meet the filing requirements for the PVRR criteria as outlined in the RFP and therefore would receive 50.625 points for meeting this criteria.

Scoring Results for the PVRR Criteria

As stated in the scoring narrative of this section, the scoring and awarding of points for the PVRR category were based on a two-step process. The table below illustrates the two-step process for each Proposal scoring for awarding points under the PVRR criterion.

Scoring Methodology for PVRR Criterion

	A	B	C	D	E	F
Line No.	Bid	Lowest to Highest Bid PVRR	Lowest to Highest Bid PVRR	50.625 pts Times Percent of Lowest PVRR	Minmum PVRR Score of 50.625 pts	Total PVRR Point Score (Column D+E=F)
1	C	$63,235,728	100.00%	50.625	50.625	101.25
2	A	$90,494,897	69.88%	35.38	50.625	86.00
3	B	$93,655,553	67.52%	34.18	50.625	84.81
4	F	$101,289,581	62.43%	31.61	50.625	82.23
5	D	$110,971,071	56.98%	28.85	50.625	79.47
6	G	$112,766,772	56.08%	28.39	50.625	79.01
7	E	$116,566,959	54.25%	27.46	50.625	78.09

Supporting IEP Analysis for Scoring the PVRR Criteria

For ease of comparison, the IEP evaluator has placed all the Proposal's PVRR's in the table below:

SPP-RFP-000003 Wolf Creek - Blackberry RFP 4A.1-1- Response Form Excel Workbook - Tab 3 - RRE ROE Summary Comparison of Each Bid's PVRR From Lowest to Highest			
Line No.	Bidder	Present Value Revenue Requirement	Dollar Difference From Lowest to Highest PVRR
1	C	$63,235,728	$0
2	A	$90,494,897	$27,259,169
3	B	$93,655,553	$30,419,825
4	F	$101,289,581	$38,053,853
5	D	$110,971,071	$47,735,343
6	G	$112,766,772	$49,531,044
7	E	$116,566,959	$53,331,231

IEP Analysis of PVRR Proposal Submissions

Analysis of Proposal A's Response

- Proposal A's PVRR is $90,494,897 (second lowest PVRR). Proposal A's PVRR is $27,259,169 higher than the lowest PVRR of Proposal C's which is $63,235,728.

- Proposal A's Tab 3 PVRR Investment total is $106,173,335. This is the second lowest dollar amount for this line item, with Proposal C having the lowest dollar amount of $85,168,938.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Analysis of Proposal B's Response

- Proposal B's PVRR is $93,655,553 (third lowest PVRR). Proposal B's PVRR is $30,419,825 higher than the lowest PVRR of Proposal C's which is $63,235,728.

- Proposal B's Tab 3 PVRR Investment total is $110,336,029. This is the third lowest dollar amount for this line item, with Proposal C having the lowest dollar amount of $85,168,938.

[redacted]

[redacted]

[redacted]

Analysis of Proposal C's Response

- Proposal C's PVRR is $63,235,728, which is the lowest PVRR.
- Proposal C's Tab 3 PVRR Investment total is $85,168,938. This is the lowest dollar amount for this line item.

[redacted]

Analysis of Proposal D's Response

- Proposal D's PVRR is $110,971,071 (fifth lowest PVRR). Proposal D's PVRR is $47,735,343 higher than the lowest PVRR of Proposal C's which is $63,235,728.
- Proposal D's Tab 3 PVRR Investment total is $141,517,007. This is the sixth lowest dollar amount for this line item, with Proposal C having the lowest dollar amount of $85,168,938.

[redacted]

<u>Analysis of Proposal E's Response</u>

- Proposal E's PVRR is $116,566,959 (seventh lowest PVRR). Proposal E's PVRR is $53,331,231 higher than the lowest PVRR of Proposal C's which is $63,235,728.

- Proposal E's Tab 3 PVRR Investment total is $148,736,632. This is the seventh lowest dollar amount for this line item, with Proposal C having the lowest dollar amount of $85,168,938.

[redacted]

[redacted]

Analysis of Proposal F's Response

- Proposal F's PVRR is $101,289,581 (fourth lowest PVRR). Proposal F's PVRR is $38,053,853 higher than the lowest PVRR of Proposal C's which is $63,235,728.

- Proposal F's Tab 3 PVRR Investment total is $116,195,796. This is the fourth lowest dollar amount for this line item, with Proposal C having the lowest dollar amount of $85,168,938.

[redacted]

Analysis of Proposal G's Response

- Proposal G's PVRR is $112,766,772 (sixth lowest PVRR). Proposal G's PVRR is $49,531,044 higher than the lowest PVRR of Proposal C's which is $63,235,728.

- Proposal G's Tab 3 PVRR Investment total is $131,616,744. This is the fifth lowest dollar amount for this line item, with Proposal C having the lowest dollar amount of $85,168,938.

[redacted]

[redacted]

[redacted]

Analysis of PVRR Investment

- One of the first line items in the PVRR spreadsheet is Investment (cost to construct the project). The dollar amount of Investment comes from the Total Estimate RRE Cost, Tab 2B, cell C36 less AFUDC cell C29. If the Proposal is going to take AFUDC it will be added back in later. The table below illustrates the Investment line item from the lowest to highest dollar amount by Proposal.

SPP-RFP-000003				
Wolf Creek - Blackberry RFP				
Response Form Excel Workbook - Tab 3 - PVRR ROE				
SPP Transmission Project:				
Lowest to Highest Dollar Investment by Bid				
Line	**Bid**	**Investment (cell 8E)**	**Dollar Difference From Lowest to Highest Investment Amount**	**Percentage Difference**
1	C	$85,168,938	$0	0.00%
2	A	$106,173,335	$21,004,397	19.78%
3	B	$110,336,029	$25,167,091	22.81%
4	F	$116,195,796	$31,026,858	26.70%
5	G	$131,616,744	$46,447,806	35.29%
6	D	$141,517,007	$56,348,069	39.82%
7	E	$148,736,632	$63,567,694	42.74%

Analysis of the Rate Base Adjustment

One of the next major PVRR calculations is Rate Base Adjustment – annual, year 1. The Rate Base is the original cost of the investment plus additions to that investment, cash working capital, materials and supplies and other long term assets. The source of information for this adjustment is calculated in Worksheet 3C, the table below illustrates the Rate Base Adjustment line item from the lowest to highest dollar value by Proposal.

[redacted]

Analysis of the O&M Expense – Annual Year 1

One of the next major PVRR calculations is Operations and Maintenance (O&M) Expense – annual, year 1. The source of information for this adjustment is calculated in Worksheet 3D. The table below illustrates the O&M expense line item from the lowest to highest dollar value by Proposal.

[redacted]

Analysis of the A&G Expense – Annual Year 1

One of the next major PVRR calculations is Administrative and General (A&G) Expense – annual, year 1. The source of information for this adjustment is calculated in Worksheet 3E. The table below illustrates the A&G expense line item from the lowest to highest dollar value by Proposal.

[redacted]

Analysis of the AFUDC

Another major PVRR calculation is Allowance for Funds Used During Construction (AFUDC). AFUDC are the carrying cost that occur during the construction of the project. The AFUDC calculation is based on a FERC formula. This FERC formula includes a debt and equity cost components. Some of the Proposals have forgone asking for AFUDC while one Respondent has asked for only the cost recovery for the debt component. The table below illustrates the AFUDC line item in the PVRR calculation from the lowest to highest dollar amount by Proposal.

[redacted]

Analysis of the WACOC

Another major PVRR calculation is Weighted Average Cost of Capital (WACOC). The WACOC is composed of debt and equity components. The calculation of the WACOC is impact not only by the cost of debt and equity but also the percentage of debt to equity funding, i.e. capitalization. For example, Respondents may have used a capitalization ratio of 60 percentage debt and 40 percentage equity. One of the reasons that the capital structure ratio is important is equity has a higher cost because it is a more risky form of investment than debt which is guaranteed being paid before equity dividends to shareholders. The table below illustrates the WACOC line item in the PVRR calculation from the lowest to highest dollar amount by Proposal. The analysis which follows this table provides a description of financing costs submitted by the Respondents in their proposals.

[redacted]

Return on Equity

One of the largest dollar value cost components in the calculation of the WACOC is the return on equity. This is the profit for the shareholder investing in the company. Since shareholders receive their dividend after all costs including debt are paid, they have a great risk, hence a higher cost. Therefore, the higher the return on equity the larger the WACOCs.

<u>Analysis of Proposal A's Response</u>

[redacted]

<u>Analysis of Proposal B's Response</u>

[redacted]

<u>Analysis of Proposal C's Response</u>

[redacted]

<u>Analysis of Proposal D's Response</u>

[redacted]

Analysis of Proposal E's Response

[redacted]

Analysis of Proposal F's Response

[redacted]

Analysis of Proposal G's Response

[redacted]

Financing costs

Each Proposal was to provide a description of all financing costs, and any relevant documentation supporting these costs specific to this project.

Analysis of Proposal A's Response

- Provided a standard description of Financing Costs. [redacted]

Analysis of Proposal B's Response

- Provided a standard description of Financing Costs. [redacted]

Analysis of Proposal C's Response

- Provided a standard description of Financing Costs. [redacted]

Analysis of Proposal D's Response

- Provided a standard description of Financing Costs. [redacted]

Analysis of Proposal E's Response

- Provided a standard description of Financing Costs. [redacted]

Analysis of Proposal F's Response

- Provided a standard description of Financing Costs. [redacted]

Analysis of Proposal G's Response

- Provided a standard description of Financing Costs. [redacted]

FERC Incentives

Each Proposal was to provide a description of any anticipated FERC Incentives and any relevant documentation detailing these incentives specific to this project.

Analysis of Proposal A's Response

[redacted]

Analysis of Proposal B's Response

[redacted]

Analysis of Proposal C's Response

[redacted]

[redacted]

[redacted]

Analysis of Proposal D's Response

[redacted]

[redacted]

Analysis of Proposal E's Response

[redacted]

Analysis of Proposal F's Response

[redacted]

Analysis of Proposal G's Response

[redacted]

Lifetime Cost of The Project to Customers

The RFP Respondent was asked to provide the lifetime cost of this project to customers.

Analysis of Proposal A's Response

[redacted]

Analysis of Proposal B's Response

[redacted]

Analysis of Proposal C's Response

[redacted]

Analysis of Proposal D's Response

[redacted]

Analysis of Proposal E's Response

[redacted]

Analysis of Proposal F's Response

[redacted]

Analysis of Proposal G's Response

[redacted]

The quantitative cost impact of material on hand, assets on hand, rights-of-way ownership, control, or acquisition

The Respondent was asked to detail any material on hand, assets on hand, rights-of-way ownership, control, or acquisition and the quantitative impact they have on this RFP Proposal.

Analysis of Proposal A's Response

[redacted]

Analysis of Proposal B's Response

[redacted]

Analysis of Proposal C's Response

[redacted]

Analysis of Proposal D's Response

[redacted]

[redacted]

Analysis of Proposal E's Response

[redacted]

[redacted]

[redacted]

Analysis of Proposal F's Response

[redacted]

[redacted]

Analysis of Proposal G's Response

[redacted]

[redacted]

[redacted]

Scoring Methodologies: or Other Attachment Y Criteria

Points will be awarded based on a detailed, quantitative response that demonstrates a reduction in the cost risk of the Project, including the following Attachment Y criteria:

- The quantitative cost impact of material on hand, assets on hand, rights-of-way ownership, control, or acquisition
- Cost certainty guarantee
- Other Comments

The IEP evaluator examined all cost certainty guarantee proposals (i.e. cost caps) submitted by Respondents and grouped them into six categories:

- Binding Dollar Cost Cap
- ROE Cap,
- % Equity Cap,
- Schedule Guarantee,
- AFUDC or CWIP in Rate Base;
- Annual Transmission Revenue Requirement (ATRR) Cap

Using these six categories the IEP evaluator reviewed each proposal to determine the effectiveness of the cost caps the Respondent offered including how the terms and conditions for each cost cap provided assurances for cost certainty guarantees. SPP retained an outside consultant to validate the concept of the matrix of the six cost caps developed by the IEP evaluator. Assessment of the quality and effectiveness of the cost caps including their terms and conditions were used by the IEP evaluator for awarding points. The IEP evaluator developed a table which compares these six cost caps terms and conditions for each Respondent's proposal. The majority of the Respondents offered similar cost cap guarantees with some differences in the terms and conditions, however, there were two cost cap guarantees which included terms and conditions that were not offered by all Respondents. These two cost cap guarantees were caps on the recovery of AFUDC/CWIP and ATRR.

Based on the analysis performed by the IEP evaluator points were awarded to each proposal based on their detailed, quantitative response which demonstrated a reduction in the cost risk of the Project.

Scoring Results for the Cost Cap Criteria

SPP-RFP-000003		
Wolf Creek - Blackberry RFP		
Other Attachment Y - Cost Caps		
Line No.	Bid	Score
1	C	22.5
2	F	21.38
3	G	21.38
4	D	20.25
5	E	20.25
6	A	19.13
7	B	19.13

4A.8: Cost Certainty Guarantee

The RFP Respondent is to detail any cost certainty guarantee and any relevant documentation specific to this project.

<u>Analysis of Proposal A's Response</u>

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

IEP Analysis

The IEP evaluator scored this proposal as a Better at 19.13 points out of a total of 22.5 points for this criterion. The Proposal has provided an acceptable level of supporting documentation regarding the terms and conditions in its cost caps.

[redacted]

Analysis of Proposal B's Response

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

- [redacted]

[redacted]

[redacted]

[redacted]

IEP Analysis

The IEP evaluator scored this proposal as a Better at 19.13 points out of a total of 22.5 points for this criterion. The Proposal has provided an acceptable level of supporting documentation regarding the terms and conditions in its cost caps.

[redacted]

Analysis of Proposal C's Response

[redacted]

[redacted]

[redacted]

[redacted]

IEP Analysis

The IEP evaluator scored this proposal as a Best at 22.5 points out of a total 22.5 points for this criteria. This Proposal has provided the best supporting documentation regarding the terms and conditions in its cost caps.

[redacted]

<u>Analysis of Proposal D's Response</u>

[redacted]

[redacted]

IEP Analysis

The IEP evaluator scored this proposal as a Better at 20.25 points out of a total 22.5 points for this criteria. This Proposal has provided a better level of supporting documentation regarding the terms and conditions in its cost caps.

[redacted]

<u>Analysis of Proposal E's Response</u>

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

IEP Analysis

The IEP evaluator scored this proposal as a Better at 20.25 points out of a total 22.5 points for this criteria. This Proposal has provided a better level of supporting documentation regarding the terms and conditions in its cost caps.

[redacted]

[redacted]

<u>Analysis of Proposal F's Response</u>

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

IEP Analysis

The IEP evaluator scored this proposal as Best at 21.38 points out of a total 22.5 points for this criteria. This Proposal has provided a better level of supporting documentation regarding the terms and conditions in its cost caps.

[redacted]

[redacted]

[redacted]

Analysis of Proposal G's Response

[redacted]

[redacted]

IEP Analysis
The IEP evaluator scored this proposal as Best at 21.38 points out of a total 22.5 points for this criteria. This Proposal has provided a better level of supporting documentation regarding the terms and conditions in its cost caps.

[redacted]

Other comments

Provide any other comments related to rate analysis the RFP Respondent(s) would like to document.

Analysis of Proposal A's Response
None.

Analysis of Proposal B's Response
None.

Analysis of Proposal C's Response
[redacted]

[redacted]

Analysis of Proposal D's Response
None.

Analysis of Proposal E's Response
None.

Analysis of Proposal F's Response
[redacted]

Analysis of Proposal G's Response
[redacted]

Part 4: The final results of the Proposal evaluations

Summary of Findings

[redacted]

SPP-RFP-000003 Wolf Creek - Blackberry RFP Comparison of Each Bid's RRE, PVRR and Other Attachment Y Factors					
Line No.	Bidder	RRE Points Scored by Bid (max pts 101.25)	PVRR ROE Points Scored by Bid (max pts 101.25)	Other Attahment Y Factors Scored by Bid (max pts 22.25)	Total Points
1	A	87.62	86.00	19.13	192.75
2	B	86.23	84.81	19.13	190.17
3	C	101.25	101.25	22.50	225.00
4	D	80.61	79.47	20.25	180.33
5	E	79.15	78.09	20.25	177.49
6	F	84.71	82.23	21.38	188.32
7	G	80.38	79.01	21.38	180.77

V: Finance

All Respondents demonstrated they have the ability to finance the Wolf Creek- Blackberry project according to the standards set forth in the RFP. Therefore, the IEP focused the scoring on how each Respondent addressed the scoring criteria as outlined in Attachment Y and the Direction to the Respondents document, in a comparison with the other Proposals.

Proposals A and B – Score 113.75

Evidence of ability to obtain financing - Score 12.5
[redacted] with Respondent planning to obtain project-level financing. Respondent demonstrated a track record of raising capital to support its power system project development and deployment. Respondent included attachments demonstrating past financings, banking relationship, and audited financial statements. This received the full score available for this criterion.

Material conditions -- Score 6.25 points
Respondent include a detailed document describing material conditions for financing a generic project with generic counterparties. The proposal collected and described material conditions and covenants, as well as fees and collateral requirements, all in one table to reflect the role and profile of these considerations. This received the highest score in the evaluation.

Financial/business plan - Score 28.12 points
Respondent provided a narrative of its preparation to provide competitive transmission proposals in general over past years, as well as describing financing strategy for this specific project. Respondent described a plan to obtain project-level financing with provision of capital requirements during construction and then conversion to long-term project finance. This was scored in the middle of the range of proposals.

Pro forma financial statements -Score 16.87 points
The Respondent provided 40-year projections for required Project Rate Base, Income and Capital Structure. These statements are supported by a narrative and direct references to other sections of the proposal package that provide the source or origin for the values shown. Only one other proposal scored higher on this criterion.

Expected financial leverage -Score 3.12 points
The Respondent plans to obtain project-level financing. However, the Respondent did not use narrative or opportunities in tables to address how the proposal has prepared for the expected debt coverage. This Proposal provided the barest minimum attention to this criterion.

Debt covenants – Score 5.62
The Respondent made a detailed list of Financing Material Conditions while stating the financing will include no Financial Covenants. The scoring of this criterion, Debt covenants, includes attention to Affirmative Covenants and Negative Covenants, which the Respondent did list. This resulted in an unclear narrative for this criterion. That caused the score to be lower than the best.

Projected liquidity- Score 18.75
The Respondent described a plan for project-level financing and observed the RFP instructions that responses should be specific to the WC-BB upgrade. Respondent provided information regarding liquidity

by describing plans to maintain a cash balance. References were provided to the cash balance in the pro forma financial statements and cash flow analysis included in Tab 4C and Tab 4D of the RFP Response Form Excel Workbook. Combined, this comprehensive narrative provided the best response to this criterion and received the highest score.

Dividend policy – Score 5.62
Proposals A & B were scored better than most for the narrative of policy and support with reference to spreadsheet analyses. The Respondent described a plan to maintain a cash balance sufficient to meet operating needs, forecasted capital expenditures, and debt repayments. The references for maintaining a balance between dividends and the needs for the Project are in Tab 4C and Tab 4D of the RFP Response Form Excel Workbook.

Cash flow analysis - Score 16.87
The Respondent provided cash flow analyses that were better than some but not the best. These analyses used the 6 lines suggested in the template provided in the RFP.

Proposal C – Score 113.13

Evidence of ability to obtain financing - Score 12.5
[redacted] Respondent planning to use corporate-level financing. Sundry deep examples were attached supporting the ability of corporate level financing to serve this project. This received the full score available for this criterion.

Material conditions – Score 5.0
Proposal C included an answer is for this criterion. The answer made reference to an attached letter of commitment from its parent company. A comparison of the commitment letter with the narrative in the response allowed for a scoring of this response in the middle of the range of responses for this criterion.

Financial/business plan – Score 31.25
Respondent described a strategy for its plan to use corporate-level financing as well as business plan for managing all the other aspects of Proposal C. The business plan description demonstrated clear attention to competitiveness and efficiency of execution, which distinguished this as the best of proposals submitted. Combined, this comprehensive narrative provided the best response to this criterion and received the highest score.

Pro forma financial statements —Score 15.0
Proposal C included the financial statements as shown in the template. Other proposals did work on this criterion that were better.

Expected financial leverage– Score 5.0
The response to this section of the RFP is very brief. The Respondent included a reference to Table 5A.3-2 in its narrative, which is also very brief.

Debt covenants – Score 5.62
The Respondent described the corporate financing arrangements that are generally less dependent on covenants when the loans are made between affiliated companies. To illustrate the narrow list of debt

covenants, the Respondent provided prior project documents used for financing a prior transmission project. This example supports the description and allows a better score.

Projected liquidity– Score 16.88
Proposal C emphasized the liquidity of the Proponent at the corporate level. As the RFP instructions call for "finance information specific to WC-BB upgrade," the more relevant information was provided in the financial statements. In the range of responses seen, Proposal C was better than some, and weaker than others.

Dividend policy – Score 5.0
The Respondent response to this criteria was indirect. In Section 5A.8 the proposal refers generally to the business plan provided in Section 5A.3. By describing the need for the corporate financing structure and debt/equity ratio creating obligations on cash flow, Respondent has provided the bare minimum of a policy for dividends.

Cash flow analysis – Score 16.88
The Respondent provided a better response to this criterion, citing both the sufficiency of expected cash flows and financial arrangements with affiliates that are not dependent on project cash flows for financing. Proposal C included cash flows metrics in Tab 4D of the RFP Response Form Excel Workbook that were a level more comprehensive and relevant than other proposals.

Proposals D and E – Score 93.13 points

Evidence of ability to obtain financing – Score 11.25 points
[redacted] Respondents are planning to obtain project-level financing for the Competitive Upgrade. Respondents provided audited financials of holding company members. The Respondents demonstrated the ability to pursue a short-term financing approach for the project utilizing internally generated funds from the owners of the project holding company to contribute equity to the Project during the construction period. The Respondents demonstrated the liquidity and financing track record of the parent companies by including annual financial reports. However, the discussion of prior experience with project-level financing was much less robust.

Material conditions - Score 5 points
Respondents stated that their proposal is not contingent on any financing conditions, but described plans for short-term and long-term borrowing. Attached financing support letter from a third-party describes numerous expected conditions. Annual reports' descriptions for corporate financings and credit agreements establish conditions and covenants. The Proposal's financing plans and descriptions differ from the brief descriptions and pro forma projections for the project's viability, and that is scored lower.

Financial/business plan- Score 25 points
Respondents plan to obtain project-level financing. The presentation made through narrative, attachments and pro-forma financial statements, projected liquidity and dividend policy was not as supportive or demonstrative of a de-risked plan as other proposals. The proposal did not describe any of the tasks it must complete or references from past project-level financing for its expectations or experience regarding the project-level financing.

Pro forma financial statements -Score 15 points
The Respondents provided 10-year projections for required Project Rate Base, Income and Capital Structure. These statements do not include components of the financing that are described in the business plan or financing structures described in the narrative.

Expected financial leverage– Score 3.12 points
The Respondents described a plan for project-level financing and the RFP states that responses should be specific to this upgrade. Respondents provided limited information regarding the liquidity and debt service coverage of the project. With an expectation that the Respondents will need a strong ability to service debt when seeking project-level financing after construction, these proposals instead illustrate a decline each year in available reserves for the project with a negative change in cash available each year. This was scored low.

Debt covenants – Score 6.25 points
The Respondents provided a project-specific bank document that included indicative covenants for the Projects. The evidence provided for this criterion was scored at the highest level, as did most of the projects seen for this RFP.

Projected liquidity– Score 9.37 points
The Respondents described a plan for project-level financing and the RFP states that responses should be specific to this upgrade. However, Respondents provided limited information regarding the liquidity and debt service coverage of the project. The information included illustrates a decline each year in available reserves for the project with a negative change in cash available each year. This was scored lower than the other proposals.

Dividend policy -- Score 3.12 points
The Respondents did not support or coordinate a description of dividend policy with other documents or narratives. The reference provided to another document makes no mention of distributions, dividends, liquidity reserves, giving little support.

Cash flow analysis -Score 15 points
The Respondents provided a minimal projection of cash flow for the project. This analysis does not include components of the financing that are described in the business plan or financing structures described in the narrative. This description of cash flow with a negative change in cash available each year is not a strong support for operations or creditworthiness and viability of the project.

Proposals F and G – Score 118.75

Evidence of ability to obtain financing - Score 12.5 points
[redacted] The Proposals F & G use a corporate finance approach using general corporate debt funding. The evidence provided for this criterion was scored at the highest level, as did most of the projects seen for this RFP.

Material conditions - Score 5 points
The Respondents state that they "do not have nor do they anticipate any material conditions that would impact the ability to execute the Project, which includes obtaining necessary financing for the Project." However, the Respondents explain that the credit agreement to be used during the construction period for financing the debt will reach the termination date before construction is completed. While the Respondents have demonstrated the ability to obtain financing, this condition in the credit arrangements merits attention and keeps the scoring of this criterion below the best.

Financial/business plan - Score 28.12 points
Respondents described plans to use corporate-level financing for the WC-BB project that included specific information regarding preparation of financial structures, timing of capital expenditures for the project as well as company strengths. The business plan description did not reflect attention to competitiveness and efficiency of execution, which distinguish the best proposals submitted.

Pro forma financial statements - Score 18.75 points
These are multi-owner Responses which include pro-forma financial statements for each owner. These statements were more comprehensive and detailed than other proposals. The evidence provided for this criterion was scored at the highest level.

Expected financial leverage - Score 6.25 points
The Respondents' narrative and tables addressed several aspects of the planned use of a [redacted] structure for financing. The split of financial obligations between owners in Project, and their differing recovery rates' structures was evident. The Respondents also referenced a leverage ratio covenant which limits the ratio of total debt for one of the parent companies. The evidence provided for this criterion was scored the highest of the projects seen for this RFP.

Debt covenants - Score 6.25 points
The Respondents plan to use corporate-level financing and provided a corporate Credit Agreement. This agreement requires a number of non-financial covenants. The evidence provided for this criterion was scored at the highest level, as did most of the projects seen for this RFP.

Projected liquidity - Score 16.87 points
The Respondents plan a corporate finance approach using general corporate debt funding. The Respondents described in narrative and with references to other sections of the proposals. The Respondents emphasized the role of an existing [redacted], which the Respondents acknowledged is before the planned completion of construction. The Respondents also attached the liquidity section of audited financial reports to illustrate the range and depth of liquidity available for these projects. This scored better than most proposals.

Dividend policy – Score 6.25
The Respondents provided several references describing the dividend policy and how that policy interacts with other aspects of the financial viability of the proposals. [redacted] This Project-specific evidence provides support for this criterion scored at the highest level of the projects seen for this RFP.

Cash flow analysis – Score 18.75
These proposals demonstrated the best response in this category of criteria.
The Respondents have provided a comprehensive estimate of cash flow and included components of the financing as well as liquidity reserves for operations.

Exhibit BW-6

FOR IMMEDIATE RELEASE – Oct. 26, 2021

Media Contacts
Meghan Sever (501-482-2393, msever@spp.org)

SPP board of directors advances transmission planning and workplace diversity

LITTLE ROCK, ARK. — During their quarterly meetings, Southwest Power Pool's (SPP) board and stakeholders approved recommendations related to transmission planning, selected a builder for a 94-mile transmission line in southeast Kansas and approved recommendations meant to further develop the organization's diverse, equitable and inclusive workforce.

SPP's Strategic and Creative Reengineering of Integrated Planning Team (SCRIPT) is a group of 16 stakeholder representatives who have worked over the last year to develop recommendations to improve transmission planning and applicable cost-allocation processes, including SPP's delayed generator interconnection study process. The board approved the SCRIPT's report of 35 recommendations and 11 sub-recommendations. Implementation of these policies is expected to reduce administrative costs, create more equitable cost sharing, increase value of transmission investment, facilitate access to new markets for energy, create more timely processes and enhance reliability and grid resiliency.

The board also approved formation of the Consolidated Planning Process Task Force to coordinate the SCRIPT's recommendations' implementation through SPP's Roadmap and prioritization processes. The SCRIPT's recommendations are expected to be assessed, developed and implemented by 2024.

The board approved an industry expert panel (IEP) recommendation for NextEra Energy Transmission Southwest, LLC to build the Wolf Creek-Blackberry project. The 94-mile, 345-kilovolt line from southeast Kansas to the Blackberry substation in Missouri will cost an estimated $85 million to construct and is expected to be complete in 2025. The IEP evaluated this project through its competitive transmission owner selection process, which is required under the Federal Energy Regulatory Commission's (FERC) Order No. 1000 for certain transmission projects. The board approved Southwest Transmission, LLC as the alternate builder.

SPP's Diversity, Equity and Inclusion (DEI) Task Force presented a report of 10 recommendations to further develop a diverse, equitable and inclusive workforce. The board approved the recommendations, which among other things prescribed reinforcing talent pipelines through historically Black colleges and universities, community programs and business resource groups; evaluating community giving and volunteer efforts; and designating oversight of a formal DEI program. SPP was recently named by *Arkansas Business* magazine as one of the Best Places to Work in Arkansas because of its strong corporate culture and benefits, among other factors.

About SPP: Southwest Power Pool, Inc. is a regional transmission organization: a not-for-profit corporation mandated by the Federal Energy Regulatory Commission to ensure reliable supplies of power, adequate transmission infrastructure and competitive wholesale electricity prices on behalf of its members. SPP manages the electric grid across 17 central and western U.S. states and provides energy services on a contract basis to customers in both the Eastern and Western Interconnections. The company's headquarters are in Little Rock, Arkansas. Learn more at SPP.org.

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Exhibit BW-7

Southwest Power Pool

Working together to responsibly and economically keep the lights on today and in the future.

SPP-NTC-210626

SPP
Notification to Construct

December 3, 2021

Mr. Marcos Mora
NextEra Energy Transmission Southwest, LLC
700 Universe Boulevard
Juno Beach, FL 33408

RE: Notification to Construct Approved Reliability Network Upgrades

Dear Mr. Mora,

On October 29, 2019, the Southwest Power Pool, Inc. ("SPP") Board of Directors ("Board") approved the Network Upgrade listed below to be constructed as part of the 2019 Integrated Transmission Planning ("ITP") Assessment. The Network Upgrade was deemed to be a Competitive Upgrade in accordance with Section I of Attachment Y of the SPP Open Access Transmission Tariff ("OATT") which requires the selection of a Designated Transmission Owner ("DTO") through the Transmission Owner Selection Process ("TOSP") in Attachment Y of the SPP OATT. On October 26, 2021, the Board concluded the Transmission Owner Selection Process for the Network Upgrade by selecting NextEra Energy Transmission Southwest, LLC ("NEET SW") as the DTO.

Accordingly, pursuant to Section 3.3 of the SPP Membership Agreement and Attachments O and Y of the SPP OATT, SPP provides this Notification to Construct ("NTC") directing NEET SW, as the DTO, to construct the Network Upgrade.

<u>New Network Upgrades</u>
Project ID: 81547
Project Name: Line - Wolf Creek - Blackberry 345 kV
Need Date for Project: 1/1/2026[1]
Estimated Cost for Project: $97,386,260 (this project cost contains Network Upgrades not included in this NTC)

[1]NEET SW guaranteed an in-service date of 1/1/2025 in the NEET SW RFP (SPP RFP000003).

SPP-NTC-210626

Network Upgrade ID: 122598
Network Upgrade Name: Wolf Creek - Blackberry 345 kV
Network Upgrade Description: Build a new 345 kV line from Wolf Creek to Blackberry with a summer emergency rating of 2512 MVA[2]
Network Upgrade Owner: NEET SW
MOPC Representative(s): Marcos Mora
TWG Representative(s): N/A
Categorization: Economic
Network Upgrade Specification: All elements and conductor must have at least an emergency rating of 2512 MVA
Network Upgrade Justification: Project identified in 2019 ITP Assessment
Estimated Cost for Network Upgrade (current day dollars): $85,168,938
Cost Allocation of the Network Upgrade: Base Plan
Estimated Cost Source: NextEra Energy Transmission Southwest, LLC
Date of Estimated Cost: 10/26/2021

Commitment to Construct

In accordance with Section III of Attachment Y of the SPP OATT, in order to become the DTO of the Network Upgrade, within seven (7) calendar days of receiving this NTC, NEET SW must (1) provide written notification to SPP that it accepts the NTC and (2) submit to SPP a deposit in accordance with Section III.2(d)(xii) of Attachment Y of the SPP OATT. NEET SW shall be deemed to have waived its right to become the DTO if these requirements are not met.

By accepting the NTC, NEET SW agrees that as the DTO selected by the Board through the TOSP, that NEET SW will complete the Network Upgrade in accordance with the RFP Proposal submitted by NEET SW in the TOSP for the Network Upgrade.

Notification of Commercial Operation

Please submit a notification of commercial operation for each listed Network Upgrade to SPP as soon as the Network Upgrade is complete and in-service. Please provide SPP with the actual costs of these Network Upgrades as soon as possible after completion of construction. This will facilitate the timely billing by SPP based on actual costs.

Notification of Progress

On an ongoing basis, please keep SPP advised of any inability on NEET SW's part to complete the approved Network Upgrade(s). For project tracking, SPP requires NEET SW's to submit

[2] 2019 ITP Assessment Study identified a minimum emergency rating of 1792 MVA. NEET SW's proposed an emergency rating of 2512 MVA in the NEET SW RFP (SPP RFP000003).

SPP-NTC-210626

status updates of the Network Upgrade(s) quarterly in conjunction with the SPP Board of Directors meetings. However, NEET SW shall also advise SPP of any inability to comply with the Project Schedule as soon as the inability becomes apparent.

All terms and conditions of the SPP OATT and the SPP Membership Agreement shall apply to this project(s), and nothing in this letter shall vary such terms and conditions.

Don't hesitate to contact me if you have questions or comments about these requests. Thank you for the important role that you play in maintaining the reliability of our electric grid.

Sincerely,

Antoine Lucas
Vice President, Engineering
Phone: (501) 614-3382 • Fax: (501) 482-2022 • alucas@spp.org

cc: Lanny Nickell - SPP
Casey Cathey - SPP
David Kelley - SPP

NEXTera ENERGY TRANSMISSION SOUTHWEST

December 6, 2021

Mr. Antoine Lucas
Southwest Power Pool
201 Worthen Dr.
Little Rock, Arkansas 72223

RE: Acceptance of Notification to Construct Approved Economic Upgrade

Dear Mr. Lucas,

On December 3, 2021, NextEra Energy Transmission Southwest, LLC ("NEET Southwest") received the Notification to Construct ("NTC") SPP-NTC-210626 issued by the Southwest Power Pool, Inc. ("SPP") for NEET Southwest to be the Designated Transmission Owner ("DTO") for the Wolf Creek-Blackberry 345 kV Transmission Line ("Network Upgrade").

In accordance with Section III of Attachment Y of the SPP Open Access Transmission Tariff ("OATT"), NEET Southwest provides this written notification to SPP confirming that it accepts the NTC and is submitting to SPP a deposit in accordance with Section III.2(d)(xii) of Attachment Y of the SPP OATT for the Network Upgrade.

NEET Southwest appreciates this opportunity given by the SPP and looks forward to working together to deliver the Network Upgrade in accordance with the terms and conditions in the RFP Proposal submitted by NEET Southwest, the SPP OATT, the SPP Membership Agreement and the NTC, for the benefit of SPP customers.

Sincerely,

Becky Walding

Becky Walding
Assistant Vice-President
NextEra Energy Transmission Southwest, LLC
Phone: 561-691-2684
Becky.Walding@nexteraenergy.com

cc: Lanny Nickell – SPP
Casey Cathey – SPP
David Kelley - SPP
Aaron Shipley – SPP
Marcos Mora – NEET
Tracy C. Davis – NEET
Matthew Boykin – NEET