AN UPDATED EXAMINATION OF FERC ORDER NO. 1000 PROJECTS

Expanded Review Shows That Benefits of Competition Remain Elusive

PREPARED FOR:
THE DATA COALITION: AMEREN SERVICES, EVERSOURCE ENERGY, EXELON CORP., ITC HOLDINGS CORP., NATIONAL GRID USA, PUBLIC SERVICE ELECTRIC AND GAS COMPANY, AND XCEL ENERGY

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EXECUTIVE SUMMARY

Since the Federal Energy Regulatory Commission ("FERC") issued Order No. 1000 in 2011, public utility transmission providers and transmission developers have participated in competitive solicitations, in regions where they exist, to determine which entities will have the opportunity to develop and recover the costs of transmission facilities included in regional transmission plans.[1] Evidence to date, including Concentric Energy Advisors, Inc.'s ("Concentric") August 2022 analysis of competitive transmission processes ("2022 Report"),[2] suggests that the benefits underlying FERC's rationale for the elimination of the Right of First Refusal ("ROFR") processes have been elusive.

In April 2019, the Brattle Group ("Brattle") issued a report that analyzed the experience to date with competitive bidding for transmission projects. Even though none of these projects had been completed at the time, Brattle estimated that competition would lead to cost savings of 20 percent to 30 percent.[3] Concentric released a report in June of 2019 ("2019 Report") raising concerns with the methodology and findings of the Brattle report. Concentric's 2022 Report, using data based on actual completed projects, did not support Brattle's estimate of cost savings under competitive solicitations for transmission. In fact, the analysis found no basis to conclude that competition in transmission had produced clear benefits either in the form of innovation or cost savings, though it did find that associated processes delay the development of transmission and the delivery of associated benefits to customers.

This report updates and expands on the research and analysis performed by Concentric in the 2022 Report by leveraging additional quantitative data that has become available in the intervening eighteen months. This data is used to update findings about the six projects studied in the 2022 Report and to analyze additional projects that have reached later stages of development or have since entered service. In addition, this report: i) expands the approach from the 2022 Report to include incumbent-developed transmission projects resulting from Order No. 1000 solicitations; and ii) makes observations about several recent processes that highlight certain challenges with Order No. 1000 solicitations.

A review of these projects has revealed the following:

- **The benefits of competitive solicitation processes remain unsupported by the totality of evidence:** An analysis of publicly available data on competitive solicitations conducted to

1 Public utility transmission providers were required to remove from FERC-approved tariffs and agreements a federal right of first refusal for a transmission facility selected in a regional transmission plan for purposes of cost allocation. This allowed, but did not require, public utility transmission providers in a transmission planning region to use competitive bidding to solicit transmission projects or project developers.

2 Competitive Transmission: Experience To-Date Shows Order No. 1000 Solicitation Fail to Show Benefits. August 2022.

3 Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value, prepared for LSP Transmission Holdings, LLC. April 2019.

date continues to show no consistent evidence of benefits flowing from competitive transmission solicitations. Rather, updated project information shows certain projects meet cost and timeline expectations, while others have experienced cost overages or delays. Our analysis includes four transmission projects undertaken by incumbent transmission developers as a result of Order No. 1000 solicitations or state ROFR laws. Three of these projects were delivered close to both budget and schedule expectations, and the fourth appears to be on budget but partially delayed.[4,5]

- **Cost cap mechanisms contain numerous exclusions that limit customer protections**: Many of the competitive solicitations conducted to date have yielded winning bids with cost containment mechanisms in the form of cost caps, which is expected in a competitive bidding model where cost is a factor in evaluating proposals. Cost containment provisions, such as cost caps, are frequently viewed as mechanisms that guarantee protection for customers from cost escalations (an assumption that is implicit in Brattle's 2019 conclusions). To view cost caps as a firm guarantee of project cost (or cost savings) greatly oversimplifies the realities of developing long-lead-time capital-intensive infrastructure. Developers commonly propose exclusions to the cost caps for unexpected or unknown events that can occur leading up to and during construction, such as project rerouting, regulatory delays, and expected but unknown costs such as financing or interconnection. It is also common for cost cap escalation provisions to account for concepts like inflation and materials cost growth. Taken together, the stated cost cap exceptions have, in some cases, overtaken the cost commitment provisions themselves and resulted in costly and time-consuming debates over cost recovery. Furthermore, the prevalence of cost cap provisions that allow for final costs to be materially different from originally contemplated contractual costs is difficult to reconcile with the assertion that "competition *ensures* cost savings." These observations around the efficacy of cost caps are based on experience to date and a review of projects in this and the prior Concentric reports.

- **Transparency limitations challenge assessment of cost cap implementation:** Cost caps come into effect in two key instances – one in the evaluation and selection of submitted projects by the Independent System Operators ("ISOs")/Regional Transmission Organizations ("RTOs") and one in the ratemaking process by FERC. In evaluating proposals, ISOs/RTOs must evaluate the allocation of risk under the disparate cost cap structures with project-specific lists of exclusions which, for complex projects like transmission, can be quite extensive. This places some ISOs/RTOs in the untenable position of accounting for complicated cost cap structures to assess cost-effectiveness in awarding projects at a point in the development process when project cost expectations may bear little resemblance to final costs in the ratemaking process before FERC. Furthermore, significant transparency and data interpretation challenges (see below) surrounding the application of the cost containment

4 Building New Transmission, Experience To-Date Does Not Support Expanding Solicitations, June 2019.

5 Competitive Transmission, Experience To-Date Shows Order No. 1000 Solicitations Fail to Show Benefits, August 2022.

measures to the final project cost make it difficult to assess how they were implemented and how they are reflected in the rates.

- **Data challenges continue to hamper review of competitive transmission outcomes:** After developing considerable experience researching competitive transmission projects, the Concentric team has identified data quality and data complexity shortcomings as a considerable challenge to rigorous analysis of competitive project outcomes. The lack of transparency around the relationship between final costs and capped costs, for example, makes it challenging not only to assess the efficacy of cost caps, but also to assert that cost caps can be relied upon as barometers for cost savings in the competitive selection process and the ratemaking process.

SECTION 1:
INTRODUCTION

FERC issued Order No. 1000 in 2011 in response to concerns about the inefficiencies and barriers hindering the development of a robust and interconnected transmission infrastructure and adopted four major reforms: i) regional transmission planning requirements; ii) interregional coordination requirements; iii) *ex ante* cost allocation requirement (regional and interregional); and iv) elimination of the ROFR in FERC-jurisdictional tariffs and agreements for facilities subject to regional cost allocation, which would effectively introduce competition for the development of such projects.

When it issued Order No. 1000, FERC eliminated the federal ROFR on a theoretical basis, identifying several reasons why it believed the elimination of ROFRs was necessary and appropriate to ensure just and reasonable rates. The Commission found that the ROFRs "created a barrier to entry"[6] and that administering transmission planning processes with a federal ROFR "may result in the failure to consider more efficient and cost-effective solutions to regional needs" and thus their elimination may give "customers…the benefits of competition in transmission development and associated potential savings."[7]

Economic theory suggests that, as long as certain conditions are met, competition should foster innovation, efficiency, and cost savings. However, in specialized industries with high fixed costs, competition can lead to the duplication of infrastructure, increased costs, and reduced overall efficiency. In an affidavit submitted to FERC by Dr. Carl R. Peterson in Docket No. RM21-17-000 ("Peterson Affidavit"), Dr. Peterson explains why Order No. 1000 does not create textbook competition and does not fundamentally alter the transmission market.[8]

In the case of competition in transmission established under Order No. 1000, one way to assess whether the hoped-for benefits of transmission competition have materialized is to review the real-world experience to determine whether the introduction of competition has contributed to achieving the objectives of Order No. 1000. To that end, Concentric was retained by the DATA Coalition to provide an updated analysis of experience with competitive transmission solicitations across the United States.[9] This analysis builds on previous reports produced by Concentric that analyzed experience with competitive projects which are now in service or in advanced stages of development.

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6 FERC Order No. 1000, 136 FERC ¶ 61,051 at P 203 (2011).

7 *Id.* at PP 225-226.

8 Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, FERC Docket No. RM21-17-000, Affidavit of Carl R. Peterson, September 19, 2022.

9 The DATA Coalition includes: Ameren Services, Eversource Energy, Exelon Corp., ITC Holdings Corp., National Grid USA, Public Service Electric and Gas Company, and Xcel Energy.

SECTION 2:

ANALYSIS METHODOLOGY AND PROJECT SCREENING CRITERIA

A. SELECTION METHODOLOGY

To assess whether the introduction of competition in transmission development has positively contributed to meeting the goals of Order No. 1000, it is important to conduct a thorough analysis of the competitive processes conducted, and projects completed, to date, to examine real-world experience with competitive solicitations and associated projects. This approach was implemented in prior Concentric reports with then-publicly available information. The goal of this report is to update and expand that empirical review.

To initiate the analysis, Concentric began with an extensive list of projects subject to regional cost allocation to establish the complete set of projects that were competitively solicited or, owing to states' laws or other prevailing rules, exempt from competition. We then applied screening criteria, as described below, to determine the projects warranting an in-depth analysis. We designed the screening criteria to provide an update on the projects assessed in the 2022 report, to expand on the prior review, and to provide a balanced assessment by including projects that met the requirements for competitive solicitations under Order No. 1000 but which were undertaken by incumbent utilities. The incumbent projects that qualified were either won in a competitive solicitation or were designated to be built by incumbent utilities as a function of state ROFR laws but which would have been subject to competition absent such laws. The projects that warranted an in-depth analysis based on this screening criteria were placed in one of two categories:

> **Category 1:** Projects Selected for Examination in the 2022 Report – The six projects examined in the 2022 Report were reviewed to determine if new information had become available since the time of the 2022 Report, and whether additional or amended conclusions could be drawn. Three screening criteria were applied in 2022 that resulted in the list of six projects reviewed:
>
> i. cost estimates greater than $50 million;
>
> ii. projects developed by non-incumbents; and,
>
> iii. projects under construction or in service.
>
> In this 2024 update, we focus on two of the six projects reviewed in our previous report for which there was new information: Delaney Colorado River Transmission/Ten West Link Project ("Ten West Link") and the Empire State Line ("Empire State").

Category 2: Order No. 1000 Projects (Competitively Solicited) and ROFR Projects - This category expands the screening criteria for Category 1 to include projects developed by incumbent transmission owners. It also captures projects that were not far enough along in development for review in the 2022 Report but now are. For this category, the following screening criteria were applied:

i. cost estimates greater than $50 million;

ii. projects developed by incumbents (as well as non-incumbent projects not already reviewed in Category 1); and,

iii. projects at least in the engineering stage of development, including:

1. projects that are now at a late enough development stage to warrant further study in the manner of the 2022 Report and for which there are emerging lessons; and,
2. projects that would have been subject to competition absent a state ROFR law ("ROFR Projects") that are being developed by incumbents and which are now at a late enough development stage to warrant further study in the manner of the 2022 Report.

B. SCREENING CRITERIA

Incumbent or Non-Incumbent Status

Proponents of the ROFR elimination under Order No. 1000 have asserted that capital cost savings will be realized as a result of the introduction of competition for the development and ownership of transmission. For these claims to be accurately assessed, it is important to review competitive projects awarded to non-incumbent developers. In the 2022 Report, we assumed that whether or not a project developed by an incumbent transmission developer was awarded as part of a competitive solicitation or directly assigned, it would experience the same outcome related to cost and schedule adherence as though it had been constructed pursuant to a ROFR.[10] In this updated analysis, Concentric has added a review of projects either won by or directly assigned to incumbent transmission developers to address concerns with imbalance in project selection criteria and lack of scrutiny of incumbent-developed projects. This revised approach is reflected in the selection of Category 2 projects.

[10] Order No. 1000 defines a "nonincumbent transmission developer" as either: (1) a transmission developer that does not have a retail distribution service territory or footprint; or (2) a public utility transmission provider that proposes a transmission project outside of its existing retail distribution service territory or footprint, where it is not the incumbent for purposes of that project. By contrast, an "incumbent transmission developer/provider" is defined as an entity that develops a transmission project within its own retail distribution service territory or footprint.

Development Status

Concentric examined projects in service or in an advanced stage of development for which there is sufficient data to allow for informed conclusions about the results of competitive processes. Cost estimates for projects at early stages of development tend to provide relatively low-quality information about how much the project will ultimately cost. Financial commitments made in winning developer bids before projects are developed and constructed add a layer of complexity to any assessment of actual cost. Examining projects that are in service or in advanced development provides the best opportunity to assess the experience with competitive solicitations and filters out projects that are too early in development to accurately draw fact-based conclusions about the competitive solicitation.

In addition, we reviewed all projects in at least the engineering phase of development for the sake of additional learnings. Two projects in the engineering phase of development are detailed in this section of the report (Hobbs to Roadrunner and Wolf Creek to Blackberry). The learnings from these projects are focused less on cost updates (which are more easily observable when a project is far enough along in development, i.e., under construction or in service), and more on other development successes or challenges (e.g., siting issues, regulatory hurdles, project selection process).

Cost Estimate

We examined projects with an estimated cost of at least $50 million. We believe that the results of competition are more transparent and easier to observe across projects of a certain size, scope, and length of construction, and that these size determinants would be broadly represented through an initial cost threshold.

C. SELECTED CASE STUDIES

The screening criteria discussed above yielded the Category 1 and Category 2 projects in Table 1 below for which an in-depth analysis was conducted. The Category 1 projects were reviewed in the 2022 Report, and only two have sufficient new information available for us to cover in depth in this report – Empire State and Ten West Link. The Category 2 projects are new to this report – either because they were developed by incumbents or because they were not at a sufficiently mature stage of development in mid-2022 – and each is analyzed in depth in this report. As a part of Category 2 project reviews, Concentric also reviewed two projects in early development stages given the unusual circumstances of their selection.

Table 1: Projects Detailed in 2024 Report

Category	Project	Region	State	Winner	Year Awarded	Status
1	Delaney Colorado River / Ten West Link (DCRT)	CAISO	CA	Abengoa & Starwood	2015	UC
1	Western NY (Empire State)	NYISO	NY	NextEra	2017	IS
Category	**Project**	**Region**	**State**	**Winner**	**Year Awarded**	**Status**
2	Sycamore to Peñasquitos	CAISO	CA	SDG&E & Citizens	2013	IS
2	Gates 500 kV (Orchard Substation)	CAISO	CA	LS Power	2020	UC
2	NY AC Docket - Segment B	NYISO	NY	NY Transco	2019	UC
2	NY AC Docket - Segment A	NYISO	NY	LS Power & NYPA	2019	IS
2	Thorofare Creek to Goff Run to Powell Mountain 138 kV	PJM	WV	Transource WV	2015	IS
2	TUCO-Yoakum-Hobbs 345 kV	SPP	TX, NM	Xcel Energy	2017	IS
2	Huntley-Wilmarth	MISO	IA, MN	ITC, Xcel	2016	IS
2	Wolf Creek to Blackberry	SPP	KS	NextEra	2021	E/P
2	Crossroads-Hobbs-Roadrunner	SPP	NM	NextEra	2023	E/P
UC **IS** **E/P**	Under Construction In Service Engineering/Procurement					

SECTION 3:

CATEGORY 1 PROJECTS: 2022 REPORT UPDATE

This section of the report includes an updated review of Category 1 projects included in the 2022 Report, as shown in Table 2 below.

Table 2: Category 1 Project Summary

Project	Developer	Region	New Info For 2024 Update
Suncrest Reactive Power	NextEra	CAISO	No
Delaney Colorado River (DCRT) / Ten West Link	Abengoa & Starwood[11]	CAISO	**Yes**
Harry Allen to Eldorado (DesertLink)	LS Power	CAISO	No
Duff to Rockport to Coleman	LS Power	MISO	No
Western NY (Empire State)	NextEra	NYISO	**Yes**
Artificial Island	LS Power	PJM	No

There are two projects that warrant additional analysis owing to evolved project circumstances: Ten West Link in California, and Empire State in New York. Based on this updated review, we offer the following key observations:

- **Ten West Link (DCRT/Lotus):** This project will likely enter service four years behind schedule and at a cost that is approximately twice the agreed-to cost cap. Costs above the cap that are allowable under contract exclusions will likely be borne by ratepayers and are among the issues FERC set for hearing and settlement procedures.[12]
- **Empire State (NextEra)**: This project was completed largely on schedule but at a cost to customers considerably higher than the cost cap due to exclusions in the First Amended and Restated Approved Project Sponsor Agreement ("APSA").

We have refined certain other data contained in the 2022 Report (as shown in Table 3), and especially note the challenges in comparing cost caps (which often do not state 100% of the anticipated project costs) to final cost estimates. Final costs are not always presented in relation to the original cost cap, nor are the results of escalation, exclusions, and other passthrough costs presented transparently.

[11] DCRT is now a joint venture led by affiliates of Lotus Infrastructure Partners.
[12] DCR Transmission, L.L.C., 184 FERC ¶ 61,199 (Sept. 2023).

Nevertheless, we are making the best possible use of the available data. A review of project costs for projects contained in the 2022 Report is presented here.

Table 3: DCRT & Empire State Updated Costs

	Project	Region	Expected In-Service Date	Actual In-Service Date	Cost Cap ($000)	Cost Cap Dollar Year	Final Cost ($000)	Final Cost Dollar Year
[1]	Ten West (DCRT)	CAISO	5/1/2020	4/1/2024*	258,961	2020$	553,300	2024$
[2]	Western NY (Empire State)	NYISO	6/1/2022	7/1/2022	110,400		264,370	2024$

[1]	Cost cap does not include interconnection costs, escalation, and other exclusions. DCRT notes pandemic-related force majeure. This project is in Settlement discussions and is expected* to enter service in Q1 2024.
[2]	Cost cap dollar year is unknown. The final cost estimate is based on 2024 projected year end rate base. 2024 is used as a proxy here for final project cost due to the fact that NEETNY agreed to settle certain unforeseeable costs and reclassify as foreseeable, under the cost cap, and will be trued up in future rate years.

When we examine the lessons from competitive bidding as exemplified through the two projects in Category 1, we note the divergence between cost caps and final project costs. FERC Commissioner Christie offered comments about the promise of cost caps with regard to DCRT. He noted:

> *"[w]hat this example shows is that a cost cap agreed upon at the time of project approval may subsequently be honored more in the breach than in the observance; in other words, the cost cap applies until it doesn't. This, of course, undermines the entire justification for approving a developer's economic project…while competitive solicitation for large, costly regional projects may be preferable to no such requirement, in and of itself it does not cure or in any way prevent consumers from being hit with exorbitant and ever-rising costs…"*[13]

Cost caps have been a common element of competitive transmission bids. While cost caps are intended to limit the costs that can be recovered, they include exclusions that allow for final project costs to exceed the dollar amount specified in the cap, often for unknown or high-risk cost categories. While it is instructive to review final project costs against the original cap for competitively bid transmission projects to examine the cost containment protections they offer, it is inappropriate to assume (at any point in the project development lifecycle) that a cost cap represents final project costs. Customers served by the Ten West Link and Empire State Lines will pay for total project costs that are higher than what would be expected based on their cost caps. These two cases reflect the reality that cost caps do not cap all costs and therefore do not represent a guarantee of overall cost savings.

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13 Available at: https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-dcr-transmission-regarding-transmission-cost#.

Furthermore, it is worth noting that cost caps come into effect in two key instances – one in the evaluation and selection of submitted projects by ISOs/RTOs and one in the ratemaking process by FERC. In evaluating proposals, ISOs/RTOs must evaluate the allocation of risk and the range of possible outcomes under disparate cost cap structures with project-specific lists of exclusions. For complex infrastructure projects like electric transmission, such lists can be quite extensive, and the challenges associated with assessing and comparing them can be significant. It is worth considering whether it is feasible to conduct such assessments in an objective and rigorous manner, and whether it is even a relevant exercise if the exceptions wind up being so permissive as to render the cost cap provisions mostly or entirely meaningless to customers. Turning to the ratemaking process, we observe that there are challenges with understanding who is responsible for cost cap implementation, how oversight is exercised, and whether there is adequate transparency to assess the accuracy and impact of cost cap or cost containment provisions in terms of ultimate impact on customers.

A. TEN WEST LINK (DCRT/LOTUS)

DCRT/Ten West Link

The Ten West Link Project is expected to enter service in the first quarter of 2024, almost four years later than anticipated, and at a cost that is twice the agreed-upon cost cap. Costs above the cap that are allowable under contract exclusions will likely be borne by ratepayers and are the subject of ongoing settlement discussions.

i) Project Overview

Ten West Link is an approximately 125-mile, 500 kV transmission line between California and Arizona that was selected by the California Independent System Operator Corporation ("CAISO") in 2015 through a competitive solicitation to fulfill a need identified in CAISO's Transmission Plan. The project is currently under construction. As described in the 2022 Report, in 2015 Ten West Link was estimated by CAISO to cost $300 million.[14]

ii) Project Cost and Timeline

The California Public Utilities Commission ("CPUC") approved a maximum allowable cost of $389 million in the project's 2021 Certificate of Public Convenience and Necessity ("CPCN") proceeding. Due to several challenges, including a route change, a change in the in-service date, changes in

[14] Delaney Colorado River Transmission Line Project, Project Sponsor Selection Report, July 10, 2015, p. 2.

interconnection costs, numerous regulatory delays, and the COVID-19 pandemic, the final in-service cost for the project is now estimated at $553.3 million.[15] This represents an approximate 40% increase over the CPUC maximum allowable cost, and is more than double the CAISO cost cap of $259 million. DCRT is seeking to recover the nearly $300 million in excess of the cost cap based on a combination of allowable exclusions and force majeure provisions under the APSA. The recovery of these costs is the subject of a FERC hearing and settlement discussions.

This project experienced several challenges that resulted in a delayed in-service date of approximately four years. According to the DCRT's filings, the Bureau of Land Management ("BLM") routinely extended the anticipated dates for completion of the draft Environmental Impact Statement ("EIS") and final EIS for a variety of reasons, including a federal furlough and the need for additional information from the applicant. In addition, the CPCN proceeding itself also experienced significant delays. CAISO increased the cost cap to reflect certain updated cost estimates, an indication of the extent to which project circumstances changed since the original APSA was agreed to (e.g., route changes, etc.). The project is expected to be in service in early-mid 2024.

On June 30, 2023, DCRT filed an application with FERC requesting acceptance of a project cost of approximately $553 million. Several parties protested DCRT's application, including the CPUC and CAISO, because DCRT's cost increase exceeded the previously established cost caps. On September 29, 2023, FERC set the matter for hearing and settlement judge procedures.[16] The initial settlement conference took place on November 21, 2023, with a status update conference scheduled for February 8, 2024, and a technical conference scheduled for March 21, 2024. It remains possible, if not likely, that the settlement proceedings will result in CAISO customers funding cost recovery for DCRT well in excess of its cost cap, and certainly well in excess of original expected project costs.

iii) Summary

When CAISO began the competitive solicitation process for Ten West Link, the new transmission line was expected to be in service no later than May 1, 2020. Yet, through a route change and delays to construction caused by regulatory delays and the COVID-19 pandemic, Ten West Link is now anticipated to enter service in early-mid 2024, almost four years later than anticipated, and at a cost over 100% higher than the initial cost cap (established circa 2015) and 40% higher than the CPUC maximum allowable cost (established in 2021). In this case, the cost caps proposed by DCRT were critical in DCRT's selection as the winning bidder. As confirmed by CAISO, it selected DCRT in the CAISO competitive solicitation to build Ten West Link due to its *materially lower project costs and its binding cost containment measures*. The primary purpose of a cost containment mechanism is to

15 DCRT Transmittal Letter, FERC Docket No. ER23-2309-000, June 29, 2023.
16 FERC Order Scheduling Initial Settlement Conference, FERC Docket No. ER23-2309-000, October 25, 2023.

protect ratepayers from significant cost increases that can have a material impact on rates.[17] Instead, the agreed-upon cost caps did not fully protect customers from the risk of cost increases, calling into question the enforceability and efficacy of cost containment mechanisms in transmission development. As noted in the Peterson Affidavit, transmission competition naturally invites the use of cost caps and is likely to create the incentive for bidders to propose even more elaborate and aggressive cost caps, only to eventually engage in *ex post* renegotiation should costs increase.[18]

B. EMPIRE STATE LINE (NEXTERA)

Empire State Line

The Empire State Line remained on schedule but was completed at a cost considerably higher than the unadjusted cost cap due to exceptions to the cost cap. Data limitations and challenges did not allow for additional insights and conclusions on final project costs.

i) Project Overview

In October 2017, NextEra Energy Transmission New York ("NEETNY") was selected by the New York Independent System Operator ("NYISO") to develop a project to address the Western New York Public Policy Transmission Need identified by the New York Public Service Commission ("NYPSC"). Empire State is a 345 kV line that connects the Dysinger switchyard in Royalton, NY to the East Stolle switchyard in Elma, NY. Project construction began in March of 2021, and NEETNY adhered to all scheduling requirements as required by NYISO. The Empire State Line entered service on time in June 2022.[19]

ii) Project Cost and Timeline

In its formula rate proceeding, NEETNY committed to cap certain costs at $110.4 million[20] as part of a settlement proceeding, defined as the sum of the following: (A) the Capital Cost Bid, defined as the amount submitted by NEETNY in response to NYISO's solicitation on the Western New York Public

17 Motion to Intervene and Comments of CAISO, FERC Docket No. ER23-2309-000, July 21, 2023.
18 Affidavit of Dr. Carl R. Peterson, September 19, 2022, p. 22.
19 Available at: https://www.empirestateline.com/content/dam/empirestateline/us/en/pdf/NEETNY_EmpireStateLine_FS.pdf.
20 Settlement Agreement, FERC Docket No. ER16-2719-000, and NextEra Energy Transmission New York, Inc., "2021 & 2022 Formula Rate Annual Projection Response to the New York Transmission Owners' Questions Provided on 12/1/2021," January 10, 2022, p. 3. Empire Third Party Costs are not detailed in the NYISO Selection Report; therefore, Concentric assumes the cost cap as reported by NEETNY in its response to the New York Transmission Owners.

Policy Transmission Need, but excluding Empire Third Party Costs; (B) contingency of 18% to be applied to the Capital Cost Bid; (C) the sum of the Capital Cost Bid and the contingency of 18%, multiplied by an inflation factor of 2.0% per year for the period of time from the submission in response to NYISO's Solicitation to the date that is one year prior to the Commercial Operation Date; and (D) Allowance for Funds Used During Construction ("AFUDC"). Pursuant to the settlement agreement approved in Docket No. ER16-2719, 20% of any prudently incurred project costs above the Cost Cap that are subject to the Cost Containment Mechanism will not earn an equity return, but NEETNY will be allowed to recover the associated depreciation and debt cost. In addition, 80% of any prudently incurred costs above the Cost Cap that are subject to the Cost Containment Mechanism will not earn any Return on Equity ("ROE") Incentive Adders on the equity portion of such costs, but NEETNY will be allowed to earn the base ROE, associated depreciation, and debt cost.

Despite remaining largely on schedule, NextEra encountered significant cost overruns, describing unforeseeable costs of approximately $86 million above the cost cap, which NEETNY stated were excluded from the project cost containment mechanism. Stakeholders did not challenge whether the costs were prudently incurred. Rather, they challenged whether these costs were properly applied to NEETNY's cost containment provisions as unforeseeable capital costs, including undergrounding of facilities; environmental protection, mitigation or remediation measures; engineering, construction and material costs; and changes in facility design or elements.[21] Through settlement discussions, NEETNY and stakeholders agreed to reclassify a portion of project costs from unforeseeable to foreseeable costs for the June 1, 2023, Rate Year 2022 Annual True-up formula rate update (and in all future iterations of the formula rate updates). This resulted in a total of $38.5 million of project costs being subject to the cost containment provisions of the Settlement Agreement.[22] Thus, it appears that $38.5 million of capital costs are eligible for recovery but would not receive ROE adders and NEETNY would forgo "return on" 20% of that capital invested (totaling $7.7 million).

We estimate final project costs of $264 million based on NEETNY's 2024 projected year-end rate base. The cost cap adjusted for escalations and exclusions is not reported publicly and not known to us. Therefore, it is not known how much the final costs that will be incurred by customers will exceed the original agreement between the developer and NYISO. What is clear is that the costs included in the formula rate are 240% higher than the unadjusted cap.

21 Available at: https://www.nyiso.com/documents/20142/33581239/NEET-NY-2023-Annual-Project-NYSEG-RGE-LIPA-Informal-Challenge-and-Response.pdf/7b858719-bfc6-5aa9-15ed-8ff1258f8ce7.

22 NextEra Energy Transmission New York, Inc. RY 2023 Annual Projected Rate and RY 2021 True-Up Informational Summary June 1, 2023, available at: https://www.nyiso.com/documents/20142/33581239/NEET-NY-2023-Annual-Projection-Informal-Challenges-Resolution-Summary.pdf/aa8197be-e5cf-e729-f2ac-9664ede833ea.

iii) Summary

Empire State achieved commercial operation in accordance with the agreed-upon schedule but at a considerably higher cost than the cost cap. Specifically, the capital costs included in the formula rate are 240% higher than the amount of the initial, unadjusted cost cap. It appears that the vast majority of the return on and of this capital amount will be recovered from customers. However, it was difficult to derive meaningful insights on the final project costs as compared to the cost cap due to limited and inconsistent publicly available data.

SECTION 4:

CATEGORY 2 PROJECTS: NEW PROJECT CASE STUDIES

Concentric has identified Category 2 projects as projects developed by non-incumbents *and* incumbents that are far enough along in development, and that are over $50 million. Concentric has identified nine projects that fall into this category. The majority of these projects were selected because they are far enough along in the development process to warrant analysis. The final two projects – Wolf Creek to Blackberry and Crossroads-Hobbs-Roadrunner – are not as far along in the development process but were identified as having procedural histories that are worth making observations about at this time. The complete list of Category 2 projects can be found in Table 4.

Table 4: Category 2 Project Summary and Key Observations

Project	Developer (Incumbency)	Region	Key Observations
Sycamore to Peñasquitos	SDG&E & Citizens (incumbent)	CAISO	Completed on schedule and 15% below estimated project cost
Gates 500 kV (Orchard Substation)	LS Power (non-incumbent)	CAISO	Under construction; inadequate data to draw conclusions
NY AC Docket – Segment A (Central East Energy Connect)	LS Power & NYPA (non-incumbent)	NYISO	Completed on schedule and below cost estimate developed by consultant at project award, though cost result relative to cost cap is difficult to assess
NY AC Docket – Segment B (New York Energy Solution)	NY Transco (joint venture of incumbent utilities)	NYISO	Under construction; partial on schedule, partial delayed in-service date; costs on budget with original NYISO estimate
Thorofare Creek to Goff Run to Powell Mountain 138kV	Transource WV (non-incumbent)	PJM	Completed approximately on schedule at 15% higher than initial cost estimate
Tuco-Yoakum-Hobbs 345 kV	Xcel Energy (incumbent)	SPP	Completed one month early and on budget
Huntley-Wilmarth	ITC & Xcel Energy (incumbent)	MISO	Completed on time and 25% below revised final MISO cost estimate
Wolf Creek to Blackberry	NextEra (non-incumbent)	SPP	Regulatory process challenges and requirement for new ROW
Crossroads-Hobbs-Roadrunner	NextEra (non-incumbent)	SPP	Challenges with independent scoring and transparency in SPP process

Concentric analyzed three non-incumbent-developed transmission projects that are in the late stages of development. One of the three non-incumbent-developed projects exhibited successful outcomes (either final or expected). The NY AC Docket – Segment A project was completed on schedule and below the initial cost estimate. The Gates 500 kV Project does not yet have sufficient cost data to make conclusions about costs, but, within its most recent formula rate filing, the developer indicated the project would be placed into service late. The Thorofare Project was completed on schedule but at 15% over the most relevant cost estimate.

Concentric reviewed four transmission projects based on our screening criteria that were awarded to and undertaken by incumbent transmission developers either through Order No. 1000 solicitations or state ROFR laws. These projects exhibited largely favorable outcomes in terms of final cost and schedule when compared to initial estimates. Three of the projects were delivered close to both budget and schedule expectations. The fourth project, NY Segment B, is under construction and appears to be on budget, although one major element of the project will be delayed beyond the initially anticipated in-service date (several others were completed early).

Based on these results, including when considered in the context of the results of the 2022 Report and in response to the 2019 Brattle Report, we continue to see no evidence that suggests competitively developed projects systematically achieve outcomes that deliver 20 to 30 percent cost savings to customers or are completed more expeditiously than incumbent-developed projects. Furthermore, we see no evidence that non-incumbent developers who win competitive solicitations generally deliver projects in a more cost-effective or more timely manner than incumbent-developed projects.

A. SYCAMORE TO PEÑASQUITOS (INCUMBENT, SDG&E AND CITIZENS)

Sycamore to Peñasquitos

The Sycamore to Peñasquitos transmission line was successfully developed and placed in operation in accordance with the project schedule and at a cost that was 15% less than the estimated project cost.

i) Project Overview

The Sycamore to Peñasquitos transmission line, a 15-mile, 230 kV project consisting of 11.5 miles of underground and 3.1 miles of overhead lines, was awarded to San Diego Gas & Electric Company ("SDG&E") and Citizens Energy Corporation in 2013 through a competitive solicitation conducted by CAISO.[23] Citizens Energy and SDG&E signed a non-binding letter of intent during the solicitation process which structured a transaction whereby Citizens Energy would have an option to acquire a leasehold interest in a portion of the project for 30 years. The Sycamore – Peñasquitos project was a

23 SDG&E FERC TO5 Formula Tariff Filing, FERC Docket No. ER19-221-000, October 30, 2018, p. 374.

reliability-driven project with additional policy benefits identified in CAISO's 2012-2013 transmission plan. CAISO approved the project in March 2013 as part of its approval of the 2012-2013 transmission plan and required an in-service date of May 2017.

ii) Project Cost and Timeline

Construction on the project started in January 2017. The project was energized in August 2018, three months after the revised in-service date. CAISO's original cost estimate for the project was $111-$221 million. The wide range in cost was due to the fact that the line could be AC or DC, and could be overhead, underground, or a combination of the two. As described within the CAISO Selection Report, the in-service date for the project was May 2017.

CAISO received bids from four different project sponsors: Abengoa T&D; Elecnor Inc.; SDG&E in conjunction with Citizens Energy Corporation; and Trans Bay Cable LLC. There are six selection factors that CAISO specified throughout the competitive solicitation process. These include:

1. Overall capability to finance, license, construct, operate, and maintain the facility.
2. Possession of existing rights-of-way ("ROWs") that could contribute to the project.
3. Experience in acquiring ROWs to facilitate approval and construction of the project.
4. Proposed schedule and demonstrated ability to meet the schedule.
5. Environmental permitting and engineering qualifications and experience.
6. Demonstrated cost containment capability.

CAISO determined that the SDG&E proposal was best situated for selection factors two, three, four, and five.[24]

The CPUC issued its final certificate for the project on October 13, 2016, and it required the project to place the majority of the transmission line underground, whereas the CAISO specifications assumed that the majority of the line would be placed aboveground and within SDG&E's existing ROWs. This decision increased the cost estimate of the project to $260 million, which included a contingency of $41 million and extended the energization date to June 2018.[25] SDG&E did not commit to a cost cap or other cost containment provisions.

In its October 2018 Transmission Owner tariff filing ("TO5"), SDG&E recorded $224.8 million for transmission capital additions between January and December of 2018, over 15% less than the $260 million that was estimated in October 2016.

24 CAISO Sycamore-Peñasquitos Project Sponsor Selection Report, March 4, 2014, pp. 62-63.
25 CAISO Transmittal Letter, FERC Docket No. ER17-1627-000, May 18, 2017, pp. 1-2.

iii) Summary

The Sycamore to Peñasquitos transmission line was successfully developed and placed in operation in accordance with the project schedule and at a cost that was 15% less than the estimated project cost. The project was developed by a consortium led by SDG&E, the local incumbent. There was no agreed-upon cost cap or other cost containment measure in this case, but the project developers appear to have effectively managed project costs consistent with estimated costs.

B. GATES 500 KV DYNAMIC REACTIVE SUPPORT PROJECT (NON-INCUMBENT, LS POWER)

Gates 500kW Dynamic Reactive Supply Project

Since this project just began construction in 2023, there is insufficient information available on which to assess the competitive process.

i) Project Overview

The Gates 500 kV Dynamic Reactive Support Project ("Gates 500 kV") ("Orchard Substation") project was awarded to LS Power's subsidiary LS Power Grid California ("LSPPC") in 2020, through a competitive solicitation conducted by CAISO. The plan identified a reliability-driven need for an approximately 800 MVAR dynamic reactive device to be installed in two equally sized blocks independently connected to the Gates Substation 500 kV bus. CAISO approved the need for the project in March 2019 as part of its approval of the 2018-2019 transmission plan. According to the CAISO Selection Report, the latest in-service date for the project is June 1, 2024.

CAISO evaluated ten applications from four project sponsors: Horizon West Transmission, an affiliate of NextEra Energy, Inc.; LS Power Grid California, a wholly-owned subsidiary of LS Power; Starwood Energy Group Global; and TransCanyon Gates, an affiliate of Berkshire Hathaway Energy Corporation and Pinnacle West Capital Corporation.

CAISO determined that there were no material differences or only slight differences among the project sponsors and their proposals across selection factors and qualification criteria.[26] One of the key selection factors and qualification criteria for which CAISO identified material differences was the cost containment selection factor.[27] According to CAISO, LS Power proposed the strongest binding cost containment commitment proposal and a schedule that provided a substantial cushion for meeting the in-service date.[28]

26 CAISO Gates Dynamic Reactive Support Project Selection Report, January 17, 2020, p. 139.
27 *Id.*
28 *Id.*

ii) Project Cost and Timeline

CAISO originally estimated the project cost to be approximately $210-$250 million.[29] LS Power offered a cap on capital costs of $68.3 million, with a cap on equity return of 9.8% and a cap on equity percentage of no more than 45% for the life of the project. LS Power also committed to an annual revenue requirement cap for the first 15 full calendar years of project operation that would not exceed $110.2 million in each of those 15 years. The revenue requirement cap would be applied annually and would include operations and maintenance costs, administrative and general costs, book depreciation, cost of debt, ROE, and taxes for the project. As described within the selection report and relayed in testimony from Mark Milburn, if, in any year, the project revenue requirement was greater than the annual revenue requirement cap, LS Power would not be able to recover those revenues in its rates, except to the extent the excess amount was attributable to excluded costs.[30] LS Power also committed to a one-time ROE incentive, which would reduce the company's ROE by 2.5 basis points for every month that the project is delayed, up to a total of 30 basis points.

The CPUC unanimously granted LS Power a permit to construct Gates 500 kV in December 2022, and construction started on the Gates 500 kV project in early 2023. LS Power noted within its LSPPC 2024 Project Posting Notice that the company does not expect to have any transmission facilities in service during the 2024 year.[31] Given this notice, it is likely that the Gates 500 kV project will not be in service by the CAISO-specified date of June 2024, and the LSPPC website currently states that that testing and energization of the facilities is expected in 2025.[32]

iii) Summary

Since the project began construction in early 2023, and there are no available updates to cost or schedule information, it is premature to assess the effectiveness of the competitive process in this instance. However, the project will enter service no less than seven months later than the ISO-specified in-service date.

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29 CAISO Gates 500 kV Dynamic Reactive Support Project Sponsor Selection Report, January 17, 2020, p. 5. As described with the CAISO Selection Report, the $210-$250 million cost estimate included a portion of the project not subject to competitive solicitation. CAISO did not provide a sole cost estimate for the parts of the project subject to competitive solicitation.

30 LS Power Grid California, Direct Testimony and Exhibits of Mark D. Milburn, FERC Docket No. ER21-195-000, October 23, 2020, p. 14. Excluded costs include transmission interconnection-related costs, changes in CAISO project requirements or scope, changes in law, and force majeure type events.

31 LS Power Grid California, LSPPC 2024 Projection Posting Notice, October 5, 2023.

32 Available at: https://www.lspgridcalifornia.com/gates/.

C. NY AC DOCKET – SEGMENT A (NON-INCUMBENT, LS POWER & NYPA)

NY AC Docket – Segment A

The Segment A project entered service on time and under cost the cost cap and project cost estimates. The project cost cap offers incentives for the developer to complete work under budget and earn additional savings for customers.

i) Project Overview

In February 2016, NYISO issued a solicitation for solutions to an identified transmission need to increase the Central East transfer capability by at least 350 MW. Segment A, the Central East Energy Connect, includes a replacement of Niagara Mohawk's existing 80-mile, 230 kV transmission line with a new 86-mile, double-circuit 345 kV line from the Edic Substation to the New Scotland Substation.[33]

NYISO received sixteen project proposals. NYISO Staff, in coordination with an independent consultant, conducted a detailed evaluation and developed a draft AC Transmission Report that detailed the results of its analysis and proposed rankings. NYISO awarded NY AC Docket Segment A (proposal designation T027) to LS Power and the New York Power Authority ("NYPA").[34] The NYISO board approved the AC Transmission Report and the selection of LS Power/NYPA's Project for Segment A in 2019.[35]

ii) Project Cost and Timeline

Construction on Segment A started in early 2021. The project entered service on time in December 2023.

NYISO and its independent consultant reviewed the cost estimates submitted by each of the developers throughout the bidding process and developed independent cost estimates for each proposal.[36] NYISO's independent consultant estimated the cost of the project (including a 30% contingency) at $750 million.[37] Note that, owing to the structure of the NYISO process, bidders do not provide a cost estimate of their own when submitting a bid.

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33 FERC Order on Formula Rate and Transmission Rate Incentives, and Establishing Hearing and Settlement Judge Procedures, FERC Docket No. ER20-716-001, May 26, 2020, pp. 5-6.

34 NYISO Board of Directors, Approval of AC Transmission Public Policy Transmission Planning Report and Selection of Public Policy Transmission Projects, April 8, 2019.

35 NYISO, AC Transmission Public Policy Transmission Plan, April 8, 2019, p. 7.

36 *Id.* At p. 110.

37 FERC Order on Formula Rate and Transmission Rate Incentives, and Establishing Hearing and Settlement Judge Procedures, FERC Docket No. ER20-716-001, May 26, 2020, p. 3, 20.

LS Power did not include any cost containment provisions within its NYISO bid. In its filing to FERC for approval of a transmission formula rate, LS Power included a cost cap of $626.8 million (representing the cost estimate developed by NYISO's independent consultant during the evaluation, plus a 30% contingency, but excluding Segment A third-party costs[38] in 2017 dollars, times LS Power's portion of ownership, and escalated for inflation plus third-party costs and AFUDC).[39] The developer also sought approval for certain incentive rate treatments. LS Power's cost cap proposal included cost-sharing provisions, whereby if eligible project costs exceeded the cost cap, the developer would receive no ROE for 20% of the eligible project costs that exceeded the cost cap and would recover no incentive ROE adders on the remaining 80% of the eligible project costs that exceeded the cost cap. [40] However, depreciation and debt costs remained recoverable irrespective of the cost cap. If eligible costs were below the cost cap, then the developers were entitled to earn certain additional incentives.

FERC found that LS Power's proposed performance-based rate incentive and cost cap had not been shown to be just and reasonable. The issues included the eligible and ineligible costs to be included in the proposed incentive such as the "other unforeseeable costs," as well as whether and how the varying rates were appropriately calibrated to risks and challenges of being over or under the cost cap.[41]

LS Power filed its Offer of Settlement on April 1, 2021.[42] In the Settlement Offer, LS Power committed to a cost cap of $316.5 million plus AFUDC (LS Power's portion of the project).[43] FERC approved the Settlement on June 17, 2021.[44] For the LS Power portion of the project, the company forecasts in its 2024 FERC Projection Formula Rate Filing a total plant in service of $466 million.[45]

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38 LS Power, Direct Testimony and Exhibits of Lawrence Willick, FERC Docket No. ER20-716-001. As defined in the testimony, Segment A third-party costs are costs that result from: (i) NYISO modifications to the Project or NYISO requirements including interconnection costs and upgrades resulting from the NYISO interconnection process; (ii) real estate-related costs incurred in any lease arrangements, purchase, easement, or license related to acquisition of rights-of-way, or access to rights-of-way; and (iii) other costs incurred as a result of action or inaction by incumbent transmission owners.

39 LS Power, Direct Testimony and Exhibits of Lawrence Willick, FERC Docket No. ER20-716-001, pp. 31-32.

40 *Id.* at p. 33.

41 FERC Order on Formula Rate and Transmission Rate Incentives, and Establishing Hearing and Settlement Judge Procedures, FERC Docket No. ER20-716-001, May 26, 2020, p. 22.

42 LS Power Grid New York Corp., Offer of Settlement, FERC Docket No. ER20-716-000, April 1, 2021.

43 *Id.* at p. 6.

44 FERC Letter Order Approving LS Power Grid New York Corporations April 1, 2021, as amended on April 9, 2021, filing of an Offer of Settlement concerning its proposed formula rate and protocols, FERC Docket No. ER20-716-000, June 17, 2021.

45 LS Power Grid New York, Annual Transmission Revenue Requirement for the 12 months ended 12/31/2024, pp. 8-9.

NYPA's cost cap is reported at $190 million, with similar cost containment provisions (i.e., sharing provisions) whereby return on capital is limited but return of capital is not.[46] NYPA's 2023 Transmission Revenue Requirement ("TRR") estimates Segment A net plant at $166 million.[47]

The Central East Energy Connect was completed on time in December 2023.[48] In a press release, LS Power publicly stated that the total project costs are anticipated to be $615 million (for both LS Power's and NYPA's portions of Segment A combined), below NYISO's independent estimate (which included 30% contingency), potentially earning the developer(s) additional incentives and providing customers with savings compared to the independent estimate provided to NYISO.[49] Concentric was not able to independently validate the difference between the LS Power Press Release (indicating $615 million total project costs) and the Formula Rate Filings estimates of $632 million ($466 million + $166 million), nor whether LS Power will ultimately earn additional incentives based on these cost outcomes.

iii) Summary

Segment A is a project that entered service on time and below the NYISO independent consultant estimate of $750 million. We note that this estimate already included a 30% contingency, and we have previously written about the issues around deriving cost savings conclusions based on planning-level estimates.[50] Relatedly, assertions of savings based on final cost results below early estimate costs (including those performed by a third party) raise the question of whether the cost results were the result of a competitive process or inaccurate cost estimating potentially combined with conservative contingencies. Were the latter to be the predominant explanation, there is nothing to say that an incumbent-developed project would not have achieved similar cost savings. Finally, we note that, in this case, the project cost cap structure provided the developer with financial bonus incentives to complete work within the cap, though it is not clear if either developer achieved this outcome.

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46 Available at: https://nyisoviewer.etariff.biz/ViewerDocLibrary/Filing/Filing4975/4975FilingSections/OATT%2014.2.3.2%20FID4975%20Redline_33107.pdf.

47 NYPA 2023 Transmission Revenue Requirement, Schedule D2.

48 Governor Hochul Announces Completion of Central East Energy Connect Transmission Line, December 13, 2023. Accessed from: https://www.governor.ny.gov/news/governor-hochul-announces-completion-central-east-energy-connect-transmission-line.

49 LS Power Press Release, available at: https://www.lspower.com/ls-power-rate-settlement-reduces-transmission-project-cost-estimate-by-200-million/.

50 NYISO, AC Transmission Public Policy Transmission Plan, April 8, 2019, p. 112.

D. NY AC DOCKET SEGMENT B (JOINT VENTURE OF INCUMBENT UTILITIES)

NY AC Docket – Segment B

Segment B is only partially in service at this time. Several major project elements were completed ahead of schedule, with one element slated to be completed ahead of the NYISO required in-service date of June 2025. Final project costs appear on track to come in below NYISO's independent estimate.

i) Project Overview

In February 2016, NYISO issued a solicitation for solutions to an identified transmission need to increase Upstate New York to Southeast New York ("UPNY/SENY") transfer capability by at least 900 MW. Segment B consists of the retirement and replacement of approximately 55 miles of transmission and station work from Schodack to Pleasant Valley ("New York Energy Solution") and the construction of 12 miles of new line from Rock Tavern Substation to Sugarloaf Substation ("Rock Tavern to Sugarloaf"). The project also includes the construction of a new substation in the Town of Dover ("Dover Station Project").

NYISO received sixteen project proposals. NYISO Staff, in coordination with an independent consultant, conducted a detailed evaluation and developed a draft AC Transmission Report that detailed the results of its analysis and proposed rankings. The draft report recommended selection of LS Power/NYPA's Segment A project and Segment B project.[51]

The NYISO Board agreed with the draft AC Transmission Report recommendation for Segment A but concluded that the more efficient solution for Segment B was the proposed National Grid/New York Transco's ("NY Transco")[52] project. The NYISO Board determined that the National Grid/NY Transco project demonstrated superior performance across a broader range of metrics, including transfer capability across transmission interfaces. The National Grid/NY Transco project showed greater transfer capability across the UPNY/SENY transmission interface as compared to the other proposed projects.[53] The Board found that the proposed National Grid/NY Transco project would significantly improve grid resilience during stressed system conditions and disruptive events, and provide greater flexibility for managing outages and generator retirements in the Lower Hudson Valley.[54] The NYISO

51 *Id.* at p. 5.
52 NY Transco is owned by affiliates of Con Edison, National Grid, AVANGRID, and CH Energy Group.
53 NYISO Board of Directors, Summary of Proposed Modifications to Draft AC Transmission Public Policy Transmission Planning Report and Proposed Selections, December 27, 2018, pp. 3-4.
54 *Id.* at p. 4.

Board concluded that the National Grid/NY Transco project was the most efficient Segment B project and concluded that final selection of the projects would be made after stakeholders had the opportunity to comment on a revised report.

The NYISO board approved the AC Transmission Report and the selection of the National Grid/NY Transco Project for Segment B in 2019. In its final report, NYISO noted that, while the project had a higher cost relative to other proposed Segment B projects, it demonstrated superior performance across a broad range of metrics.[55] NYISO awarded NY AC Docket Segment B (proposal designation T019) to NY Transco[56] with an anticipated in-service date of December 2023.[57]

ii) Project Cost and Timeline

NYISO and its independent consultant reviewed the cost estimates submitted by each of the developers throughout the bidding process and developed independent cost estimates for each proposal.[58] NYISO's independent consultant's evaluation of the proposed solution estimated the cost of the project (including a 30% contingency) at $479 million.[59] Importantly, the independent consultant cost estimate was not all-inclusive and did not include, "among other things, (i) the creation of the Van Wagner Capacitor Bank Station to house the two new 135 MVAR 345 kV capacitor banks, (ii) the Rock Tavern to Sugarloaf component, (iii) the installation of two new 750 MVA 345 kV PARs at a new Dover station, (iv) real estate and land acquisition costs, facility acquisition and removal costs, and costs incurred as a result of the Connecting Transmission Owner(s) to the extent that the foregoing costs were not assumed in the NYISO's evaluation and selection, and (v) project development costs incurred by the Developer prior to selection of the Transmission Project by the NYISO Board of Directors."[60] Such costs may reasonably be expected to be considerable and these substantial cost element omissions must therefore be accounted for when making cost comparisons at later phases in the development cycle.

The CPCNs for all components of the project were approved by March 2023.[61,62,63] Cost information was redacted in each of the three proceedings.

55 NYISO, AC Transmission Public Policy Transmission Plan, April 8, 2019, p. 7.
56 NY Transco is wholly owned by affiliates of Con Edison, National Grid, AVANGRID, and CH Energy Group.
57 NYISO Board of Directors, Approval of AC Transmission Public Policy Transmission Planning Report and Selection of Public Policy Transmission Projects, April 8, 2019.
58 NYISO, AC Transmission Public Policy Transmission Plan, April 8, 2019, p. 110.
59 NYISO, AC Transmission Public Policy Transmission Plan, April 8, 2019, p. 112, Project T019.
60 NYISO Filing of Second Amended and Restated Development Agreement Between NYISO and NY Transco re: Service Agreement No. 2510, FERC Docket No. ER24-865, January 12, 2024, PDF p. 54 (Section 6 of Service Agreement No. 2510).
61 NYPSC Order Adopting Joint Proposal, NYPSC Docket No. 19-T-0684, February 11, 2021.
62 NYPSC Order Granting Certificate of Environmental Compatibility and Public Need, NYPSC Docket No. 20-T-0549, September 9, 2021.
63 NYPSC Order Granting Certificate of Public Convenience and Necessity, NYPSC Docket No. 23-E-0081, pp. 18-19.

Construction on the New York Energy Solution started in March 2021 and was completed in November 2023. Construction on Rock Tavern to Sugarloaf started in August 2022 and was completed in September 2023. Construction on the Dover Station Project commenced in March 2023 and is expected to be completed by early 2024.[64] Pursuant to a November 21, 2023, notification to NYISO of expected delays, NYISO agreed to extend the required project in-service date to June 30, 2025.[65]

On December 4, 2014, NY Transco filed a request with FERC to approve its formula rate filing. NY Transco filed its Offer of Settlement on August 21, 2017 and stated that the Settlement would only apply if NY Transco was selected as the developer for one or both of the projects.[66] FERC approved the Settlement on November 16, 2017.[67] NY Transco received an ROE of 9.65% for all Segment B project expenses, unforeseeable costs in excess of 5% of the cost cap, third-party costs, project development costs, future AC investments, and future projects.[68] The Settlement Agreement also included a 100-basis-point ROE incentive adder to apply to any project investment incurred up to the cost cap.

Within the Settlement Agreement, NY Transco committed to a cost cap that consisted of the following items – the Capital Cost Bid submitted to NYISO on April 29, 2016, for the AC Transmission Project multiplied by an 18% contingency in lieu of the generic 30% contingency in the Capital Cost Bid of NYISO, multiplied by an inflation factor of 2.0% per year from April 2016 to the date of the selection of the AC Project Developers and AFUDC accrued prior to inclusion of construction work in progress ("CWIP") in rate base. Pursuant to the cost containment mechanism, 20% of certain costs above the cap will not receive an equity return (but NY Transco will recover depreciation and debt cost) and the other 80% will receive an equity return but not be eligible for any FERC-granted incentives. Certain "unforeseeable costs" receive separate rate treatment. The cost cap structure also includes a tiered incentive ROE framework should certain project costs fall below the cost cap.[69]

The best estimate of project costs to-date is NY Transco's 2024 year-end rate projection combined gross plant in service ($617 million)[70] plus forecasted CWIP for end-of-year 2024 ($85 million).[71]

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64 Available at: https://nytransco.com/dover/.

65 NYISO Filing of Second Amended and Restated Development Agreement Between NYISO and NY Transco re: Service Agreement No. 2510, FERC Docket No. ER24-865, January 12, 2024, p. 3.

66 NY Transco Filing of Offer of Settlement, FERC Docket No. ER15-572-006, August 21, 2017, p. 6.

67 FERC Letter Order Approving NYISO's August 21, 2017 Offer of Settlement, FERC Docket No. ER15-572-000, November 16, 2017.

68 NY Transco Filing of Offer of Settlement, FERC Docket No. ER15-572-000, August 21, 2017, p. 8.

69 NY Transco Filing of Offer of Settlement, FERC Docket No. ER15-572-006, August 21, 2017, Offer of Settlement pp. 8-14 (sections 3.2-3.5).

70 Estimated as sum of gross plant in service listed in NY Transco's Transmission Revenue Requirement projection for 2024 for: New York Energy Solution, Segment B Additions (RTS) and Dover PAR, p. 23.

71 NY Transco Transmission Revenue Requirement projection for 2024, p. 39.

Together, these project components total $702 million.[72] However, this total cost accounts for the entire project cost a includes third-party costs ($157 million) and the Rock Tavern to Sugarloaf Component ($85 million). NY Transco does not appear to report separately the expected costs of the Dover PARS in its formula rate projection, as they and other parts of the Dover Station Project are currently being accounted for through CWIP. Notwithstanding the inability to adjust for the cost of the Dover PARS and certain other project elements not included in the NYISO independent consultant cost estimate (e.g., Van Wagner Capacitor Bank Station), we attempt to calculate a cost estimate to allow an apples-to-apples comparison of the current Segment B cost outlook with the NYISO independent consultant cost estimate. To achieve this, we adjusted the total project cost ($702 million) by subtracting the third-party costs and the Rock Tavern Sugarloaf Component to yield a total cost of $460 million. While imprecise and probably inclusive of some additional costs that should be excluded, for the purposes here this cost may be compared to the NYISO independent consultant cost estimate of $479 million.

iii) Summary

Certain components of the NY AC Docket Segment B project were completed ahead of schedule, while others are behind schedule but expected to be completed in 2024. The original anticipated in-service date was December 2023. The New York Energy Solution and Rock Tavern to Sugarloaf projects were completed ahead of schedule, while the Dover Station Project is slightly behind schedule.

Based on current data and projections, it appears that the Segment B project will be completed at a cost that is roughly in line with the estimates developed by the NYISO independent consultant at the time of the project award. Once final project cost data is available following the project's completion, it will then likely be feasible to perform a more precise analysis that directly compares the cost elements included in the NYISO independent consultant estimate to the same cost elements of the project completed by NY Transco.

Due to the lack of transparency regarding starting point cost caps versus "final" or applicable cost caps in nominal dollar-year terms that are adjusted for the various escalation factors or other allowances, it is challenging to accurately assess if final (or near final) project costs are tracking close to the allowable project expense under the adjusted cap. In addition to the challenges in assessing the final project costs relative to selection-stage cost estimates owing to escalation factors, the same issues arise with comparing final or near-final costs to planning-level cost estimates that may have systemic issues with accurate estimation.

72 NY Transco, Projected Annual Transmission Revenue Requirement for the 12 Months Ended 12/31/2024, September 9, 2023.

E. THOROFARE CREEK TO GOFF RUN TO POWELL MOUNTAIN 138 KV (NON-INCUMBENT, TRANSOURCE WV)

Thorofare Creek to Goff Run to Powell Mountain 138 kV

The Thorofare project was completed within months of its expected in-service date. At an estimated project cost of \$72.0 million and a final project cost of \$82.6 million, this project was completed at a cost that was 15% higher than originally estimated. There was no cost cap proposed for this project.

i) Project Overview

The Thorofare Creek to Goff Run Powell Mountain 139 kV Project ("Thorofare Project") was awarded through PJM's Regional Transmission Expansion Plan ("RTEP") process in 2015 to solve thermal violations impacting reliability in several counties in West Virginia. The initial project consisted of a new 138 kV transmission substation near Rutledge, West Virginia, a new 138 kV tap substation near Monongahela Power Company's Power Mountain – Goff Run Transmission Line, and 15 miles of a new 138 kV transmission line from Appalachian Power Company's existing Thorofare Creek Substation to the new 138 kV substation near the Powell Mountain – Goff Run line. PJM awarded the Thorofare Project to Transource West Virgina, a partnership between American Electric Power ("AEP") and Evergy, in 2015.[73] The original in-service date for the project was June 1, 2019.

ii) Project Cost and Timeline

The project had an original estimated project cost of \$59.5 million.[74] Transource requested a base ROE of 10.5% and a 50-basis-point adder for an RTO participation incentive, in recognition that Transource West Virginia has committed to turn over control of any transmission assets it develops and owns to PJM.[75] On September 4, 2015, FERC conditionally approved the proposed formula rate, and set for hearing and settlement judge procedures the depreciation rate and base ROE. In its initial order, FERC did not find the proposed ROE to be just and reasonable.[76] In January 2016, Transource filed an Offer of Settlement.[77] Staff opposed the Offer of Settlement and argued the 10% ROE did not

73 Transource WV is a wholly-owned subsidiary of Transource Energy, a partnership between American Electric Power (AEP) and Evergy focused on the development and investment in competitive electric transmission projects across the U.S.

74 FERC Order on Transmission Formula Rate Proposal and Incentives and Establishing Hearing and Settlement Judge Procedures, FERC Docket No. ER15-2114-000, September 4, 2015, P 4.

75 Transource West Virginia Proposed Formula Rate Filing, FERC Docket No. ER15-2114, July 7, 2015, p. 7.

76 FERC Order on Transmission Formula Rate Proposal and Incentives and Establishing Hearing and Settlement Judge Procedures, FERC Docket No. ER15-2114-000, September 4, 2014, p. 9.

77 Transource West Virginia Offer of Settlement, FERC Docket No. ER15-2114-000, January 8, 2016, p. 14.

meet the fair and reasonable standard.[78]Ultimately, on December 5, 2016, FERC approved the Settlement Agreement, finding that the settlement was fair and reasonable, despite a dissent from Commissioner Colette D. Honorable disagreeing with this finding.[79]

On November 19, 2015, Transource West Virginia filed its application for a CPCN with the Public Service Commission of West Virginia ("WVPSC").[80] On May 5, 2016, Transource, Commission Staff, and the Consumer Advocate Division entered into a Joint Stipulation and Agreement for Settlement ("Joint Stipulation"), which recommended that three new substations be built, and the transmission route be modified. The updated cost estimate from these modifications was approximately $72 million.[81] On June 29, 2016, the WVPSC approved the Joint Stipulation and granted Transource West Virginia a CPCN to construct the Thorofare Project.[82] On April 21, 2017, PJM authorized the modification of the project as required by the WVPSC.

Construction on the project started in 2017 and it was put into service in late 2019. In the company's June 2021 filing of its true-up adjustment to the 2020 Projected Transmission Revenue Requirement, Transource recorded a transmission gross plant in service of $82.6 million and a general and intangible gross plant in service of $360 thousand.[83]

The project's 2020 TRR represents a project cost that is approximately 15% higher than the estimated cost at the time of CPCN approval and 39% higher than the expected cost when the project was selected by PJM.

iii) Summary

The Thorofare Project was completed within months of its expected in-service date with a final project cost of $82.6 million. This project was completed at a cost that was 15% higher than estimated during the CPCN proceeding. There were no cost containment provisions offered for the Thorofare Project.

78 Initial Comments of Commission Trial Staff Opposing, in Part, Offer of Settlement, FERC Docket No. ER15-2114-000, p. 14.

79 FERC Letter Order Approving Transource West Virginia Filling of Settlement, FERC Docket No. ER15-2114-000, December 5, 2016, Letter Order P 8 and attached Honorable Dissent p. 1.

80 WVPSC Docket No. 15-1870-E-CN.

81 Transource West Virginia Joint Stipulation and Agreement, WVPSC Docket No. 15-1870-E-CN, May 5, 2016, p. 11.

82 WVPSC Order Approving Joint Stipulation and Agreement for Settlement and Grants a Certificate of Convenience and Necessity, WVPSC Docket No. 15-1870-E-CN, June 29, 2016.

83 Transource West Virginia Informational Filing of Annual True-up Adjustment to 2020 Projected Transmission Revenue Requirement, FERC Docket No. ER15-2114-000, June 30, 2021, p. 5.

F. TUCO-YOAKUM-HOBBS 345 KV TRANSMISSION LINE (INCUMBENT, XCEL ENERGY)

Tuco-Yoakum-Hobbs 345 kV Transmission Line

Xcel completed the Tuco-Yoakum-Hobbs 345 kV Transmission Line on budget and a month before its required in-service date. There was no cost cap proposed for this project.

i) Project Overview

On May 19, 2014, Southwest Power Pool ("SPP") provided Xcel Energy's ("Xcel") Southwestern Public Service Company ("SPS") with a notification to construct the Multi-TUCO-Yoakum-Hobbs 345 kV transmission line project in New Mexico and Texas. The project was identified in the SPP High Priority Incremental Load ("HPIL") Study Report as a means of addressing loading violations on the underlying network and voltage violations due to insufficient power supply to the network load in the service area. The project was approved by the SPP Board of Directors in April 2014.

There are five distinct parts of the project. Network Upgrade ID 50447 consists of a new 107-mile, 345 kV line from Tuco to Yoakum, estimated to cost $161 million.[84] Project 50451 is a new 345/230 kV 560 MVA transformer at Yoakum Substation, estimated to cost $5 million. Project 50452 is an expansion of the existing Hobbs Substation to accommodate 345 kV terminals and the installation of a new transformer at Hobbs Substation, estimated to cost $10.2 million. Project 50457 is a new 52-mile, 345 kV line from Hobbs to Yoakum Substation, estimated to cost $59.6 million. Project 50919 is an installation of necessary 345 kV terminal equipment at Yoakum associated with a new 345/230 kV transformer, estimated to cost $1.7 million.

ii) Project Cost and Timeline

SPP estimated the total cost of the project to be $238 million, in 2014 dollars. The SPP-required in-service date for the upgrades was June 2020. Since the project's selection pre-dated the implementation of SPP's Order No. 1000 process, the project was not offered for competitive solicitation and the incumbent utility, Xcel, had the right to develop the project. The Tuco-Yoakum-Hobbs 345 kV Transmission Line is a project that would be subject to competition under SPP's current process if not for Texas' ROFR law and the project was developed in the period since the finalization of Order No. 1000.

Xcel filed for three different Certificates of Convenience and Necessity ("CCN") for the main components of the project. For the portion of the transmission line with Yoakum and Gaines Counties,

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[84] SPP Notification to Construct Approved High Priority Upgrades, May 19, 2014, p. 11.

Xcel filed its CCN with the Public Utility Commission of Texas ("PUCT") on June 25, 2015. Of the thirteen route proposals, SPS selected the modified route N which was estimated to cost approximately $45,218,752.[85] The CCN was granted by the PUCT on March 22, 2016.

On June 29, 2016, Xcel filed an amended application with the PUCT for a CCN for its proposed transmission line within Hale, Hockley, Lubbock, Terry, and Yoakum Counties, in addition to upgrades at the Yoakum and Tuco Substations. The total estimated cost to construct the route was approximately $142,103,460.[86] The CCN was granted by the PUCT on September 21, 2017.

On June 21, 2017, Xcel filed the final application for a CCN with the New Mexico Public Regulatory Commission for the transmission line and associated upgrades within Lea County, which extended from the New Mexico/Texas state line to SPS's Hobbs Generating Substation. The estimated cost for the project within the application was $50.9 million. The Commission approved the application and granted Xcel the CCN on November 29, 2017.[87]

The initial estimated cost for the entire project was approximately $238.2 million.[88] The project was completed in May 2020. We estimate the final project costs as the sum of the beginning balances from the SPS 2022 Transmission Annual Revenue Requirement Workbook for each of the project components is shown below:

Table 5: Transmission Revenue Requirement Gross Plant Balances

Project ID	Beginning Plant Balance
UID 50447	$132,562,158[89]
UID 50451	$9,701,619[90]
UID 50452	$14,113,711[91]
UID 50457	$80,359,997[92]
Total	**$236,737,485**

iii) Summary

85 PUCT Order, PUCT Docket No. 44726, March 22, 2016, p. 6.
86 PUCT Order, PUCT Docket No. 46042, September 21, 2017, p. 14.
87 New Mexico Public Regulatory Commission ("NMPRC") Order, NMPRC Docket No. 17-00143-UT.
88 Sum of Tuco-Yoakum-Hobbs transmission line CPCN/CCN Orders estimated CapEx. PUCT Order, PUCT Docket No. 44726, March 22, 2016. PUCT Order, PUCT Docket No. 46042, September 21, 2017. NMPRC Order, NMPRC Docket No. 17-00143-UT.
89 Southwestern Public Service Co., Transmission Formula Rate Template and Supporting Worksheets, Schedule 1 Annual Revenue Requirement 2022, p. 318.
90 *Id.* at p. 320.
91 *Id.* at p. 306.
92 *Id.* at p. 428.

Xcel was able to complete this project on time, entering service in May 2020 against a required in-service date of June 2020 and on budget based on an estimated project cost of $238.2 million and a final project cost of $236.7 million.

G. HUNTLEY-WILMARTH TRANSMISSION LINE (INCUMBENTS, XCEL AND ITC)

Huntley-Wilmarth Transmission Line

Xcel and ITC completed the Huntley-Wilmarth Transmission Line on time and approximately 25% below the revised final MISO cost estimate.

i) Project Overview

In September 2016, the Midcontinent Independent System Operator, Inc. ("MISO") proposed its 2016 Transmission Expansion Plan ("MTEP 16") for approval by the MISO Board of Directors. On December 7, 2016, the MISO Board of Directors approved MTEP 16, which included 394 projects totaling $2.8 billion of investment. The plan included one Market Efficiency Project: the Huntley-Wilmarth 345 kV Transmission Line in Southern Minnesota and Iowa. The project was proposed to mitigate congestion and strengthen the high-voltage power delivery system. The project consists of three components: the upgrade of the Huntley Substation and the Wilmarth Substation and the construction of a new 50-mile, 345 kV transmission line between the two substations. MISO provided a cost estimate range for the project of $88 to $108 million.[93] Since Minnesota and Iowa have state ROFR laws which give the utilities the first right to build transmission, ITC Holdings ("ITC") and Xcel developed the projects. This project is relevant for this analysis as such projects, absent state ROFR laws, would likely be subject to competition. The Huntley-Wilmarth project had a projected in-service date by the end of 2021.

ii) Project Cost and Timeline

Xcel and ITC filed an application for a certificate of need for construction and for a route permit for the project with the Minnesota Public Utilities Commission ("Minnesota PUC") on January 17, 2018,[94] and January 22, 2018,[95] respectively. Both the route and certificate for need were approved on August 5, 2019.[96] In the order approving the project's siting, the Minnesota PUC revised the project's route

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93 MISO 2016 Transmission Expansion Plan, p. 105.
94 Minnesota PUC Docket No. E-002, ET-6675/CN-17-184.
95 Minnesota PUC Docket No. E-002, ET-6675/TL-17-185.
96 Minnesota PUC Order Finding Environmental Impact Statement Adequate, Granting Certificate of Need, Issuing Route Permit, and Requiring Additional Analysis, Minnesota PUC Docket Nos. E-002, ET-6675/CN-17-184 & E-002, ET-6675/TL-17-185, August 5, 2019.

and scope by ruling that over 20 miles of the line needed to be double-circuited with monopole structures. The double-circuiting of one portion of the line allows for collocation with an existing transmission line, which mitigates the amount of corridor that needs to be cleared and had the smallest environmental impact of all the options.[97] This Minnesota PUC decision increased the cost estimate to $160 million.[98] Subsequently, MISO conducted a variance analysis for the project as mandated by the MISO Tariff, which revised the cost estimate for the project to $155.7 million. [99] The final capital cost information for each component of the project is presented in Table 6, which shows a final project cost of $117.5 million, more than 25% below both the PUC and MISO-approved cost levels.

Table 6: Expenditures to Date for All Three Project Components from the Q1 2022 MISO Quarterly Status Reports[100]

Project Component	Final Cost
Huntley Substation Modifications	$2,451,000
Huntley-Wilmarth 345 kV Transmission Line	$110,882,000
Wilmarth Substation	$3,435,000
Total	**$116,768,000**

iii) Summary

Construction on the project commenced in 2020 and was completed in 2021. The project was placed in service approximately 25% *below* MISO's final cost estimate. This project was included for review as it would have been subject to competition absent a ROFR law. The project was subject to traditional regulatory oversight approaches and cost management tools, like MISO's Variance Analysis process.

H. WOLF CREEK TO BLACKBERRY (NON-INCUMBENT, NEXTERA)

Wolf Creek to Blackberry

For this project, the SPP competitive bidding process failed to consider local concerns and involve the Kansas Corporation Commission in its final selection, which led to friction amongst numerous parties and selection of a project with incremental environmental and landowner impacts.

97 *Id.* at p. 14.
98 *Id.*
99 Reply Comments of ITC Transmission, FERC Docket No. RM21-17-000, November 30, 2021, p. 10.
100 Huntley-Wilmarth Project MISO Regionally Cost Shared Project Reporting Analysis, Q1 2022.

i) Project Overview

In 2019, as part of its annual Integrated Transmission Planning ("ITP") process, SPP identified the Wolf Creek-BlackBerry Project as a necessary economic project to increase transmission capability and relieve transmission congestion from western Kansas, east to SPP load centers.[101] The project was 1 of the 44 projects recommended by the 2019 ITP but made up more than half the mileage of transmission included. SPP approved the Wolf Creek-BlackBerry Project as a Competitive Upgrade open to competitive bidding.

Seven bids from four bidders were submitted. NextEra Energy Transmission Southwest ("NEET Southwest") was selected as the winning bidder, with a bid of approximately $85.2 million. On February 28, 2022, NEET Southwest filed an Application with the Kansas Corporation Commission ("KCC") requesting an Order granting a CCN for the project.[102] On August 29, 2022, the KCC granted NEET Southwest a limited CCN as a transmission-only public utility in Kansas to construct, own, operate, and maintain an approximately 94-mile, single-circuit 345 kV transmission line from the existing Wolf Creek Substation in Kansas to the existing Blackberry Substation in Missouri.[103] The approval was contingent upon compliance with specific conditions. Included among those conditions was a comprehensive evaluation of the double-circuit option with a nearby Evergy-owned transmission line. More specifically, Evergy and NEET Southwest were directed to work collaboratively and in good faith to consider and evaluate the double-circuit option for a 25-mile portion of the line.

The project is expected to be in service by January 1, 2026.

ii) The Double-Circuit Option

On January 24, 2023, NEET Southwest filed an application requesting that the KCC issue a siting permit offering the right to construct a single-circuit 345 kV transmission line.[104] Per the ordering requirements of the CCN, NextEra did evaluate the prospect of developing the double-circuit option. According to NEET Southwest witness Mayers, there are no projects in the United States with a double-circuit made up of two different utilities' lines.[105] NEET Southwest developed a report on the double-circuit option and presented three different scenarios.

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101 SPP Engineering 2019 Integrated Transmission Planning Assessment Report, November 6, 2019.

102 Next Era Energy Transmission Southwest, Application for a Certificate of Convenience and Necessity to Construct Transmission Facilities in the State of Kansas, KCC Docket No. 22-NETE-419-COC, February 28, 2022.

103 KCC Order on Application for Certificate of Convenience and Necessity, KCC Docket No. 22-NETE-419-COC, August 29, 2022.

104 Next Era Energy Transmission Southwest, Application for Transmission Line Siting Permit, KCC Docket No. 23-NETE-585-STG, January 24, 2023.

105 KCC Order on Siting Application, Docket No. 23-NETE-585-STG, May 24, 2023, pp. 9-11.

In the first scenario, the double-circuit was to be built using Evergy's design criteria in NEET Southwest's ROW, the construction costs would be approximately $10.7 million dollars higher than the base case (no double-circuiting) and would cause a one-to-two-year delay, costing customers $14.5 to $29 million in lost production cost savings.[106]

In the second scenario, if the double-circuit was built using NEET Southwest's design criteria in NEET Southwest's ROW, the construction would be approximately $1.8 million dollars lower than the base case but would cause a one-to-two-year delay, resulting in $14.5 to $29 million in lost production cost savings to customers.[107]

In the third scenario, if the double-circuit was built using Evergy's design criteria in Evergy's ROW, the construction costs would be approximately $22.7 million dollars higher and also cause a two-to-three-year delay costing customers $29 to $45 million in lost production cost savings.[108]

Ultimately, the report concluded that the double-circuit would not be a reasonable alternative as it would result in at least a one-year in-service delay. NEET Southwest additionally reported that the double-circuit would increase the complexity of the line without providing benefits to landowners in the near term.

iii) Dissent of KCC Commissioner Dwight Keen

On May 24, 2023, the KCC approved a siting permit establishing the route, with no double-circuiting, for the Wolf Creek to Blackberry 345 kV transmission line in Southeast Kansas.[109] KCC concluded that, while the SPP's bidding and selection process was extensive, the design of the Industry Expert Panel ("IEP") was devoid of direct input from the KCC. Staff witness Leo Haynos recommended that "the Commission consider approaching SPP to allow states the opportunity to participate in developing routing parameters to include in a Request for Proposal for any future competitively bid transmission lines."[110] The KCC believes that the competitive solicitation process will be improved if input from relevant state siting authorities is incorporated early in the process. The KCC also opened an investigation into the principles and priorities to be used in future line siting proceedings.

KCC Chair Susan Duffy and Commissioner Andrew French voted in favor of approving the line siting permit. Commissioner Dwight Keen voted against approving the line siting permit and filed a dissent objecting to locating the line parallel to an existing Evergy line and to not remanding the matter to SPP for reconsideration of double-circuiting the lines on shared poles and in ROWs or for other options to reduce landowner impact for roughly one-fourth of the route. More specifically,

106 Direct Testimony of Jacquelyn Blakley, KCC Docket No. 23-NETE-585-STG, January 24, 2023, pp. 6-10.
107 *Id.* at p. 10.
108 *Id.* at p. 12.
109 KCC Order on Siting Application, KCC Docket No. 23-NETE-585-STG, May 24, 2023.
110 Direct Testimony of Leo-Haynos, KCC Docket No. 23-NETE-585-STG, February 21, 2023, p. 29.

Commissioner Keen believed that the KCC should have decided that the portion of the shared route between Evergy and NEET Southwest be co-located or "double-circuited" on a single set of poles with an existing nearby or adjacent Evergy transmission line to avoid having two major electric transmission lines sited in parallel.[111] He also believed that NEET Southwest and Evergy should negotiate a Memorandum of Understanding ("MOU") governing the double-circuited lines and coordinate the construction, operating procedures, access sharing, and cost sharing arrangements.[112] Finally, Commissioner Keen believed that the KCC's proposal for double-circuiting be remanded to SPP for its review and consideration of the KCC's double-circuit proposal.

Commissioner Keen found that the flawed SPP vetting process precluded or excluded KCC Staff from providing timely input regarding local issues and concerns in the consequential RFP and IEP process. SPP would have benefited from involving the KCC at the outset of its review process.[113]

Commissioner Keen concluded the following:

> *"the quest for expediency and results in achieving regional electric grid transmission planning and execution goals should never override or supplant the absence of adequate and timely consideration of the very real long-term consequences to be visited by large transmission lines on landowners and other affected local stakeholders. In this instance, an SPP transmission line evaluation and selection process that is acknowledged to be flawed should not proceed to fruition without reconsideration and redress*."[114]

iv) Summary

Wolf Creek to Blackberry is a representative example of siting issues that frequently arise in the development of transmission projects. In this case, the KCC and SPP were in conflict over the project's vetting and approval process, which ultimately added friction to the competitive process. The result is two transmission lines sited in close proximity to one another, likely resulting in additional strain on developers, customers, and landowners. Furthermore, the underlying process added delay and cost to advancing a result that did not clearly deliver benefits to customers. It can logically be concluded that had a ROFR been in place, double circuiting or co-locating the line on existing or adjacent incumbent lines would have allowed for a more efficient solution.

111 Dissent of Commissioner Keen to KCC Order on Siting Application, KCC Docket No. 23-NETE-585-STG, May 24, 2023, pp. 7-9.
112 *Id.* at p. 9.
113 *Id.* at p. 10.
114 *Id.* at p. 11.

I. CROSSROADS HOBBS ROADRUNNER (NON-INCUMBENT, NEXTERA)

Crossroads-Hobbs-Roadrunner

Within the SPP competitive solicitation process, the IEP did not recommend the lowest cost project to the SPP Member Advisory Committee. The IEP struggled to provide a response to the SPP Board of Directors on why the highest cost project was recommended, leading to delay and confusion.

i) Project Overview

SPP's IEP met August 2022 to evaluate anonymous bids to build a 345 kV double-circuit line in eastern New Mexico from Crossroads through Hobbs to Roadrunner in segments totaling 143 miles. The upgrade, initially estimated to cost $376.3 million, was proposed by Xcel Energy subsidiary SPS as an alternative to a previously identified project in the 2021 Integrated Transmission Plan.[115] Competitive bidding for the project was approved by the Board in July 2022.

SPP received three proposals for its RFP. Two of the three proposals (Proposals A and B) that were considered were submitted by NextEra, and the other (Proposal C) was submitted by SPS. The only difference between the two proposals submitted by NextEra were the size of the conductors and their related costs. Some of the main differences between Proposal C (SPS) and Proposals A and B (NextEra) are the estimated project cost and the construction timeline. From a cost standpoint, the proposal that was selected was ~25% *higher* than the lowest cost estimate.[116] The project is expected to be in service no later than May 2026.

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115 Industry Expert Panel Transmission Provider Public Report Crossroads-Hobbs-Roadrunner 345 kV, July 3, 2023, p. 8.

116 *Id.*

Table 7: Scoring Results

Scoring Results Matrix SPP-RFP-000006 Crossroads-Hobbs-Roadrunner 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
B	$ 291,614,575	$ 276,234,780	192.00	189.00	222.25	196.13	124.00	923.38	Yes	100.00	1023.38
A	$ 282,740,742	$ 268,203,525	178.00	189.00	222.25	198.52	124.00	911.77	Yes	100.00	1011.77
C	$ 220,000,000	$ 212,252,524	178.00	192.00	216.75	213.75	101.00	901.50	Yes	100.00	1001.50
Average	$ 264,785,106	$252,230,276	182.67	190.00	220.42	202.80	116.33	912.22			1012.22

The IEP scores each proposal across five different categories: Engineering Design, Project Management, Operations, Rate Analysis, and Finance. Proposal B received the highest points in engineering design, operations, and finance. Ultimately, the IEP recommended proposal B (proposed by NextEra), which accumulated the most points in the scoring system. Proposal B also had the highest scores across three of the five categories and placed second in another. Proposal B had the highest construction cost estimate at $291.6 million.[117] Proposal C, proposed by SPS, estimated to cost $220 million, was selected as the alternative project. Proposal C received the highest points in project management and rate analysis. However, Proposal C was the only proposal that did not include a cost cap which appears to have led to a reduction of 11.25 within the Rate Analysis category compared to the other proposals.[118]

The proposals submitted by NextEra and SPS had different in-service dates. Proposal A and B both had an in-service date of May 2026, while proposal C had an in-service date of May 2025. The IEP concluded that the in-service date of Proposal C was very compressed and infeasible.[119]

ii) SPP Review

On July 26, 2023, the SPP Member Advisory Committee rejected the IEP's recommendation.[120] The recommendation from the IEP to award the project to NextEra only received three "for" votes. Twelve members abstained, and seven voted against. According to SPP, the IEP failed to provide satisfactory responses to questions from the Board of Directors about why the most expensive proposal was recommended.[121] The SPP Member Advisory Committee also asked several questions about the

117 *Id.* at p. 7.
118 *Id.*
119 *Id.* at p. 52.
120 SPP Board of Directors and Members Committee Meeting, July 24, 2023.
121 Tom Kleckner, RTO Insider SPP Board Rejects Recommended Competitive Project, July 26, 2023. Accessed from https://www.rtoinsider.com/51374-spp-board-rejects-competitive-project/.

timelines of the winning bid. After the meeting, the Member Advisory Committee agreed to reconvene in three weeks where the SPP Board of Directors would debate and discuss the IEP recommendation and select the designated transmission owner ("DTO").

After the July meeting, the Board of Directors sent a list of questions to the IEP to be answered before the next meeting. The questions were focused on the solicitation process, cost guarantee, rates, and financing.

Three weeks later, on August 15, the SPP Member Advisory Committee regrouped and endorsed the IEP's initial direction.[122] The SPP Board of Directors approved a "notification to construct" award to NextEra as the Crossroads-Hobbs-Roadrunner transmission project's DTO.

SPP Director Larry Altenbaumer stated, "as a board member, I don't have the credentials or the analytic ability to independently develop my own recommendation, and I don't think it is either the job of me as a board member or the IEP to try to resolve deficiencies in terms of proposals that are submitted."[123] He continued with, "I remain a very strong supporter of the competitive process, but in the end, my conclusion is that the shortfalls we have in this particular process were largely shortfalls in terms of what had been submitted by proposals."[124]

Director Alternbaumer was still largely unsatisfied with the IEP's responses to questions asked by the Board. Specifically, when asked if the panel would have made the same recommendation had the scores been the same, the IEP acknowledged that the scores were very close and concluded that, based on the information presented in the proposals, the IEP stands by its recommendations as stated within the report.

iii) Summary

Crossroads-Hobbs-Roadrunner is an example of where the competitive solicitation process may not always lead to selection of projects that appear to deliver the most cost savings to customers or do so on the most expedient basis. SPP's IEP selected a project that had a cost estimate over $70 million higher than the next lowest bidder because it scored the highest in its evaluation criteria. While selection of a higher price project is not necessarily a drawback of the process – as such projects may bring more long-term benefits to customers in certain instances – it nonetheless raises questions. Among others, it is worth considering how much weight, if any, should be afforded to cost containment offers included in bids. Cost containment provisions, as borne out by analysis done by Concentric and others, have not always proven to result in cost savings or even cost containment. Our analysis in this paper demonstrates that cost caps should be scrutinized, especially to the extent

122 SPP Board of Directors and Members Committee Meeting, August 15, 2023.
123 SPP Board of Directors and Members Committee Meeting, July 24, 2023.
124 *Id.*

they lead to the selection of higher cost projects simply because those proposals give the appearance of limiting cost exceedances. Furthermore, the selected project also had a later in-service date than other proposed projects, which implies a delay in when customers will start to realize the benefits of its construction. The largest difference between Proposal B and Proposal C (SPS) was Proposal C's lower score in the finance criteria based largely on the absence of a cost cap. Further, SPP's IEP failed to recognize the value of the earlier in-service date of Proposal C, a significant issue in an area of rapid load growth. Overall, this project offers a case study into the challenges of objective scoring of hard-to-compare proposals, the benefits to competitors that can be gained by strategic offer design (i.e., offering cost caps despite their strength), and overarching issues with putting RTO/ISO staff and board members in the place of economic regulators.

SECTION 5:
CONCLUSIONS

Our analysis of competitive solicitations conducted to date has led to the following conclusions:

- Building on prior work done by Concentric, a thorough and updated analysis of publicly accessible data related to competitive solicitations conducted to date still does not offer a foundation for asserting that competition in transmission results in cost savings. While some projects have come in on or under budget, others have come in considerably over budget. The data and accompanying analysis fail to support the idea that competition invariably leads to "cost savings" in the transmission sector, or that such savings should be expected on a systematic basis. Our analysis included transmission projects undertaken by incumbent transmission developers as a result of Order No. 1000 solicitations or state ROFR laws Three of the projects were delivered close to both budget and schedule expectations, while the fourth is expected to be on budget but is partially delayed.
- Many of the projects selected through competitive solicitations thus far have included cost caps as a tool for advancing proposals through the selection process and as a means of creating the expectation of cost containment. However, all of these cost cap mechanisms incorporate exemptions for unforeseeable costs, which are known to significantly impact final project costs in large infrastructure projects. Competitive solicitations, by their nature, incentivize proposals with cost containment mechanisms, yet cost caps obscure the actual determination of cost savings since all cost caps have exclusions, and actual costs as compared to capped costs are often markedly different. Importantly, the application of the cost containment mechanism to the final project costs (and therefore, the costs recovered from customers in rates) is generally not transparent.
- Cost caps are relevant in two crucial instances: during the assessment and selection of proposed projects by ISOs/RTOs, and during the ratemaking process overseen by FERC. When reviewing proposals, ISOs/RTOs must consider the distribution of risk within diverse cost cap frameworks, accompanied by project-specific lists of exclusions, and navigate subjective comparisons of dissimilar proposals. Furthermore, this evaluation occurs at a stage in the development process where project costs may not align closely with final costs determined in the ratemaking process before FERC. Additionally, the implementation of cost containment measures in the ultimate ratemaking process presents considerable transparency and data interpretation challenges, making it difficult to understand how these measures were executed and reflected in costs borne by customers.
- While there is an abundance of data available on competitive solicitations, there are inconsistencies across various data and information sources, such as project estimates, final

costs, dollar years, and cost cap exclusions. These limitations undermine the ability to support a finding about the cost savings benefits of competition and, indeed, create challenges for any systematic review of the relative success of competitive transmission processes.

APPENDIX A:
COMPLETE LIST OF PROJECTS CONSIDERED FOR EVALUATION

Project	Developer	Region	Expected In-Service Date	Order No. 1000 or ROFR
Fort McMurray West	ATCO & Quanta	AESO	2019	O1000
Sycamore to Peñasquitos	SDG&E & Citizens	CAISO	2018	O1000
Greg to Gates	PG&E & BHE & Citizens	CAISO		O1000
Suncrest Reactive Power	NextEra	CAISO	2017	O1000
Estrella Substation	NextEra	CAISO	2019	O1000
Miguel Reactive Power	SDG&E	CAISO	2017	O1000
Spring (Morgan Hill) Substation	PG&E	CAISO	2021	O1000
Wheeler Ridge Junction Sub.	PG&E	CAISO	2020	O1000
Delaney Colorado River / Ten West Link (DCRT)	Abengoa & Starwood [1]	CAISO	2020	O1000
Harry Allen to Eldorado (DesertLink)	LS Power	CAISO	2020	O1000
Round Mountain	LS Power	CAISO	2024	O1000
Gates 500 kV	LS Power	CAISO	2024	O1000
Boston RFP (Mystic)	Eversource & National Grid	ISONE	2024	O1000
Duff to Rockport to Coleman	LS Power	MISO	2020	O1000
Hartburg-Sabine Junction	NextEra	MISO	2023	O1000
Western NY (Empire State)	NextEra	NYISO	2022	O1000
NY AC Docket - Segment A	LS Power & NYPA	NYISO	2023	O1000
NY AC Docket - Segment B	NY Transco	NYISO	2023	O1000
Thorofare Project	Transource WV	PJM	2019	O1000
Artificial Island	LS Power	PJM	2020	O1000
AP South	AEP/Transource	PJM		O1000
Larrabee Tri-Collector Solution Project (NJ OSW)	MAOD and JCP&L [2]	PJM	2032	O1000
North Liberal to Walkemeyer	Mid Kansas Electric Co	SPP		O1000
Wolf Creek to Blackberry	NextEra	SPP	2025	O1000
Sooner-Wekiwa 345 kV	Transource MO	SPP	2025	O1000
Butler-Tioga	NA – withdrawn prior to award	SPP		O1000
Minco-Pleasant Valley-Draper	NextEra	SPP	2024	O1000
Crossroads-Hobbs-Roadrunner Transmission Line	NextEra	SPP	2026	O1000
Propel Alternate Solution 5	NYPA and NY Transco	NYISO	2030	O1000
Collinsville Project	LS Power	CAISO	2028	O1000
Manning Project	LS Power	CAISO	2028	O1000

Project	Developer	Region	Expected In-Service Date	Order No. 1000 or ROFR
Newark Project	LS Power	CAISO	2028	O1000
Metcalf Project	LS Power	CAISO	2028	O1000
LTRP No. 17 Hiple to Duck Lake	LS Power	MISO	2030	O1000
LTRP No. 17 Hiple to Duck Lake	Michigan Electric Transmission Company	MISO	2030	ROFR
Aroostook Renewable Gateway	LS Power	ISONE	2028	O1000
Leland Olds Station-to-Tande 345 kV Transmission Project	Basin Electric Power Cooperative	SPP	2025	ROFR
Roundup-to-Kummer Ridge 345 kV Transmission Line	Basin Electric Power Cooperative	SPP	2025	ROFR
Tande- and Wheelock-to-Saskatchewan 230 kV Transmission Project	Basin Electric Power Cooperative	SPP	2027	ROFR
Maple River-Red River 115 kV Transmission Line	Xcel Energy	MISO	2019	ROFR
TUCO-Yoakum-Hobbs 345 kV Transmission Line	Xcel Energy	SPP	2020	ROFR
LTRP No. 18 Onedia - Nelson Rd.	Michigan Electric Transmission Company	MISO	2029	ROFR
LTRP No. 1 Jameston - Ellendale	Otter Tail Power Company and MDU	MISO	2028	ROFR
LTRP No. 2 Big Stone South - Alexandria - Cassie's Crossing	Otter Tail Power Company and Missouri River Energy Services	MISO	2030	ROFR
LTRP No. 3 Iron Range - Benton County - Cassie's Crossing	Minnesota Power and Great River Energy	MISO	2030	ROFR
LTRP No. 4 Wilmarth - North Rochester - Tremval	Grid North Partners [3]	MISO	2028	ROFR
LTRP No. 5 Tremval - Eau Claire - Jump River	Grid North Partners [3]	MISO	2028	ROFR
LTRP No. 6 Tremval - Rocky Run - Columbia	Grid North Partners [3]	MISO	2029	ROFR
LTRP No. 7 Webster - Franklin - Marshalltown - Morgan Valley	ITC Midwest, MidAmerican Energy, and Cedar Falls Utilities	MISO	2028	ROFR
LTRP No. 8 Beverly - Sub 92	ITC Midwest, MidAmerican Energy, and Cedar Falls Utilities	MISO	2028	ROFR
LTRP No. 9 Orient - Denny - Fairport	ITC Midwest, MidAmerican Energy, and Cedar Falls Utilities	MISO	2030	ROFR
LTRP No. 10 Denny - Zachary - Thomas Hill - Maywood	TBD	MISO	2030	O1000
LTRP No. 11 Maywood - Meredosia	TBD	MISO	2030	O1000
LTRP No. 12 Madison - Ottumwa - Skunk River	ITC Midwest, MidAmerican Energy, and Cedar Falls Utilities	MISO	2029	ROFR
LTRP No. 13 Skunk River - Ipava	ITC Midwest, MidAmerican Energy, and Cedar Falls Utilities	MISO	2029	ROFR
LTRP No. 14 Ipava - Maple Ridge - Tazewell - Brokaw - Paxton East	TBD	MISO	2029	O1000

Project	Developer	Region	Expected In-Service Date	Order No. 1000 or ROFR
LTRP No. 15 Sidney - Paxton East - Gilman South - Morrison Ditch	TBD	MISO	2028	O1000
LTRP No. 16 Morrison Ditch - Reynolds - Burr Oak - Leesburg - Hiple	TBD	MISO	2029	ROFR
Huntley-Wilmarth Transmission Line	ITC, Xcel	MISO	2021	ROFR

[1]	Abengoa Declared bankruptcy shortly after the project was awarded. Starwood/Lotus is developing the project.
[2]	Mid-Atlantic Offshore Development ("MAOD") is a joint venture between Shell & EDF.
[3]	Grid North Partners is a Joint initiative of 11 transmission utilities in Minnesota, North Dakota, South Dakota, and Wisconsin
[4]	Winning bid is $49.8 million (2016$) per selection report; rate base cap is $58.1 million per Selected Developer Agreement.

CONCENTRIC ENERGY ADVISORS

APPENDIX B:

CATEGORY 1 PROJECT COST DETAIL

	Project	Region	Expected In-Service Date	Actual In-Service Date	Delay (Yrs)	Cost Cap ($000)	Cost Cap Dollar Year	Final Cost ($000)	Final Cost Dollar Year
[1]	Suncrest Reactive Power	CAISO	6/1/2017	2/1/2020	2.7	42,288	2015$	53,000	2021$
[2]	Ten West (DCRT)	CAISO	5/1/2020	4/1/2024*	3.9	258,961	2020$	553,300	2024$
[3]	Harry Allen to Eldorado (DesertLink)	CAISO	5/1/2020	8/1/2020	0.3	147,000	2020$	200,238	2020$
[4]	Duff to Rockport to Coleman	MISO	1/1/2021	6/11/2020	(0.6)	58,100	2020$	54,200	2020$
[5]	Western NY (Empire State)	NYISO	6/1/2022	7/1/2022	0.1	110,400		264,370	2024$
[6]	Artificial Island	PJM	4/1/2019	5/1/2020	1.0	146,000	2014$	149,084	2022$

[1]	Cost cap does not include all project costs, is not in same dollar year terms as final project costs, and final project cost of $53 million is based on 2021 year-end Tx rate base. CPCN approval separately established a maximum allowable cost of $49 million.
[2]	Cost cap does not include interconnection costs, escalation, and other exclusions. DCRT notes pandemic-related force majeure. This project is in Settlement discussions and is expected* to enter service in Q1 2024.
[3]	Cost cap does not include all project costs and contains provisions for certain exclusions, including interconnection and financing costs. Final costs under the cost cap are estimated at $144.7 million and are within the allowed cost cap according to DesertLink.
[4]	Winning bid is $49.8 million (2016$) per selection report; rate base cap is $58.1 million per Selected Developer Agreement.
[5]	Cost cap dollar year is unknown. Final cost estimate is based on 2024 projected year end rate base. 2024 is used as a proxy here for final project cost due to the fact that NEETNY agreed to settle certain unforeseeable costs and reclassify as foreseeable, under the cost cap, and will be trued up in future rate years.
[6]	Cost cap dollar year assumed to be 2014 based on escalation index described in DEA.

APPENDIX C:

CATEGORY 2 PROJECT COST DETAIL

	Project	Region	Order No. 1000 or ROFR	Expected In-Service Date	Actual In-Service Date	Region's Cost Estimate or Early Cost Estimate	Region Cost Estimate Dollar Year	[8] Est CapEx ($000)	Cost Cap ($000)	Actual Cost
[1]	Sycamore to Peñasquitos	CAISO	O1000	Jun-18	Sep-18	111,000 - 221,000	2013$		259,670	224,832
[2]	Gates 500 kV (Orchard Substation)	CAISO	O1000	2024		210,000 - 250,000	2019$		68,300	
[3]	NY AC Docket - Segment B	NYISO	O1000	Dec-23		479,000	2018$			460,000
[4]	NY AC Docket - Segment A	NYISO	O1000	Dec-23	Dec-23	750,000	2018$		626,762	632,536
[5]	Thorofare Project	PJM	O1000	2019	2019	59,500		72,000		82,950
[6]	TUCO-Yoakum-Hobbs 345 kV Transmission Line	SPP	ROFR	2020	2020	237,543	2014$	238,222		236,737
[7]	Huntley-Wilmarth Transmission Line	MISO	ROFR	2021	2021	88,000 - 108,000	2016$	155,700		117,551
	Wolf Creek to Blackberry	SPP	O1000	2025		85,200				
	Crossroads-Hobbs-Roadrunner Transmission Line	SPP	O1000	2026		291,600				

[1]	Region's cost estimate dollar year assumed to be 2013$ based on the 2012/2013 planning cycle. SDG&E did not commit to a cost cap in its bid. The cost cap reported is the maximum allowable cost determined in the CPCN proceeding (approved in 2016), which includes contingency of $41 million. CAISO adopted this figure in its 2017 Amended APSA. $225 million actual project cost is based on SDG&E's transmission formula rate filing and a forecast of transmission capital additions between January 2018-December 2019. A more complete estimate could not be found.
[2]	Region's cost estimate includes portion of the project not subject to competitive solicitation. Region's cost estimate dollar year assumed to be 2019$ based on 2018/2019 planning cycle. Cost cap dollar year was not determined. Cost cap is subject to certain escalations and exclusions.
[3]	Region's cost estimate is based on independent consultant evaluation of proposed solution; includes 30% contingency. Actual cost estimate from Transco 2024 YE Rate Projection, gross plant in service for NYES – 3rd party costs – Rock Tavern Sugarloaf Component.
[4]	Region's cost estimate is based on independent consultant evaluation of proposed solution; includes 30% contingency; NYPA portion of project estimated at $281 million, LS Power portion estimated at $469 million. Cost cap is $316.5 million plus AFUDC plus escalation. Project costs greater than the binding cost cap will forgo ROE and certain incentives, but still recoverable as return of plant (depreciation) and debt return on plant (not equity). Project costs below cost cap will earn additional incentives. Final project cost estimated as LS Power Segment A 2024 YE projection + NYPA Segment A 22 YE ATRR (2023 and 2024 TRR not yet available).
[5]	Project scope increased after PJM 2015 TEAC.
[6]	Estimated costs are based on PUCT and NMPUC CCN orders. Xcel also lists an "estimated project cost" on its website of $242 million (see: powerfortheplains.com).
[7]	MISO conducted a variance analysis for the project as mandated by the MISO Tariff and adopted a revised Baseline Cost Estimate of the project of $155.7 million. CPCN application estimates a total cost of $140 million (2016$) for the Purple-BB-L Route.
[8]	Estimated CapEx is provided as an additional data point in addition to any applicable cost cap. ROFR projects do not have project sponsor agreements with the ISO. The NY AC projects have no regional cost estimate but do have upfront CapEx estimates.

APPENDIX D:

DATA SOURCES

Project	Data Category	Quantity ($000)	Reference and Notes
Suncrest Reactive Power	Region's Cost Estimate	50,000-75,000	CAISO Suncrest Reactive Power Project Selection Report, January 6, 2016, p. 5.
Suncrest Reactive Power	Cost Cap	42,288	Approved Project Sponsor Agreement, May 16, 2017, p. 46.
Suncrest Reactive Power	Actual Cost	53,000	Horizon West Transmission Actual Annual Transmission Revenue Requirement for the 12 months ended 12/31/2021, 2021 average transmission rate base number.
DCRT	Region's Cost Estimate	300,000	Delaney-Colorado River Transmission Line Project Sponsor Selection Report, July 10, 2015, p. 2.
DCRT	Cost Cap	258,961	Declaration of Jason Crew in Support of Petition of Modification, Docket No. A.16-10-012, October 12, 2016, p. 9.
DCRT	Actual Cost	553,300	Motion to Intervene and Comments of CAISO, Docket No. ER23-2309-000, July 21, 2023, p. 16.
DesertLink	Region's Cost Estimate	120,000	2013-2014 CAISO Transmission Plan, July 16, 2014, p. 258.
DesertLink	Region's Cost Estimate	182,000	ISO 2013-2014 Transmission Planning Process Supplement Assessment of Harry Allen Eldorado 500 kV Transmission Project, December 15, 2014, p. 2.
DesertLink	Region's Cost Estimate	144,000	Harry Allen-Eldorado 500 kV Transmission Line Project Sponsor Selection Report, January 11, 2016, p. 5.
DesertLink	Cost Cap	147,000	First Amended and Restated Approved Project Sponsor Agreement (APSA) between Desertlink LLC and CAISO, p. 48.
DesertLink	Actual Cost	200,238	DesertLink 2020 Annual Update Attachment A, July 1, 2021.
Duff to Rockport to Coleman	Region's Cost Estimate	58,900	MISO Selection Report of Duff-Coleman EHV 345 kV Competitive Transmission Project, December 20, 2016, p. 9.
Duff to Rockport to Coleman	Cost Cap	58,100	Second Amended and Restated Selected Developer Agreement between Republic Transmissions and MISO, November 15, 2019, p. 70.
Duff to Rockport to Coleman	Actual Cost	54,200	Duff Coleman Regionally Cost Shared Project Report Reporting Analysis, Quarterly Status Report, Complete as of June 11, 2020, p. 1.
Empire State	Region's Cost Estimate	181,000	NYISO Western New York Public Policy Transmission Planning Report, October 17, 2017, p. 42.
Empire State	Cost Cap	110,400	NextEra Energy Transmission New York, Inc. 2021 & 2022 Formula Rate Annual Projection Response to the New York Transmission Owners' Questions Provided on December 1, 2021, p. 3.

Project	Data Category	Quantity ($000)	Reference and Notes
Empire State	Actual Cost	264,370	NextEra Energy Transmission New York Projected Annual Transmission Revenue Requirement for the 12 Months Ended 12/31/2024, Appendix A, p. 2.
Artificial Island	Cost Cap	146,000	Artificial Island Designated Entity Agreement, Issued July 16, 2019, Docket No. ER19-1981-000, PDF p. 29.
Artificial Island	Actual Cost	149,084	Silver Run Electric 2022 Annual Rate Filing True-Up, p. 33.
Sycamore to Peñasquitos	Region's Cost Estimate	111,000-221,000	CAISO Sycamore-Peñasqutios Project Sponsor Selection Report, March 4, 2014, p. 2.
Sycamore to Peñasquitos	Cost Cap	259,670	Decision Granting Certificate of Public Convenience and Necessity for the Sycamore-Peñasquitos 230 kV Transmission Line Project, Application 14-04-011, October 13, 2016, p. 19.
Sycamore to Peñasquitos	Actual Cost	224,832	SDG&E Fifth Transmission Owner Formula Rate Tariff Filing, Docket No. ER19-221-000, October 30, 2018, PDF p. 378.
Gates 500 kV	Region's Cost Estimate	210,000-250,000	CAISO Gates 500 kV Dynamic Reactive Support Project Sponsor Selection Report, January 17, 2020, p. 5.
Gates 500 kV	Cost Cap	68,300	Order Accepting Transmission Owner Tariff and Formula Rate, Docket No. ER21-195-000, June 29, 2021, p. 2.
NY AC Docket – Segment B	Region's Cost Estimate	479,000	NYISO AC Transmission Public Policy Transmission Plan, April 8, 2019, p. 112.
NY AC Docket – Segment B	Actual Cost	460,000	NY Transco, Projected Annual Transmission Revenue Requirement for the 12 months ended 12/31/2024.
NY AC Docket – Segment A	Region's Cost Estimate	750,000	NYISO AC Transmission Public Policy Transmission Plan, April 8, 2019, p. 112.
NY AC Docket – Segment A	Cost Cap	626,762	LS Power, Direct Testimony and Exhibits of Lawrence Willick, Docket No. ER20-716-001, pp. 31-32.
NY AC Docket – Segment A	Actual Cost	632,536	LS Power-NY Annual Transmission Revenue Requirement for the 12 months ended 12/31/2024. NYPA 2023 Transmission Revenue Requirement, Schedule D2.
Thorofare Project	Region's Cost Estimate	59,500	FERC, Order on Transmission Formula Rate Proposal and Incentives and Establishing Hearing and Settlement Judge Procedures, Docket No. ER15-2114-000, September 4, 2014, pp. 8-9.
Thorofare Project	Estimated CapEx	72,000	Transource West Virginia Joint Stipulation and Agreement, Docket No. 15-1870-E-CN, May 5, 2016, p. 11.
Thorofare Project	Actual Cost	82,950	Transource West Virginia Informational Filing of Annual True-Up Adjustment to 2020 Projected Transmission Revenue Requirement, Docket No. ER15-2114-000, June 30, 2021, p. 5.

Project	Data Category	Quantity ($000)	Reference and Notes
Tuco-Yoakum-Hobbs 345 kV Transmission Line	Region's Cost Estimate	237,543	SPP Notification to Construct Approved High Priority Upgrades, May 19, 2014, p. 11.
Tuco-Yoakum-Hobbs 345 kV Transmission Line	Estimated CapEx	238,222	Sum of Tuco-Yoakum-Hobbs Transmission Line CPCN/CCN Orders Estimated CapEx. Texas Public Utility Commission, Order, Docket No. 44726, March 22, 2016. Texas Public Utility Commission, Order, Docket No. 46042, September 21, 2016. New Mexico Public Regulatory Commission, Order, Docket No. 17-00143-UT.
Tuco-Yoakum-Hobbs 345 kV Transmission Line	Actual Cost	236,737	Southwestern Public Service Co., Transmission Formula Rate Template and Supporting Worksheets, Schedule 1 Annual Revenue Requirement 2022, pp. 306, 318, 320, 428.
Huntley-Wilmarth Transmission Line	Region's Cost Estimate	88,000-108,000	MISO 2016 Transmission Expansion Plan, p. 105.
Huntley-Wilmarth Transmission Line	Estimated CapEx	155,700	Reply Comments of ITC Transmission, Docket No. RM21-17-000, p. 10.
Huntley-Wilmarth Transmission Line	Actual Cost	116,718	Huntley-Wilmarth Project MISO Regionally Cost Shared Project Reporting Analysis, Q1 2022.
Wolf Creek to Blackberry	Cost Estimate	85,200	SPP IEP Transmission Provider Public Report Wolf Creek – Blackberry 345 kV, October 12, 2021, p. 10.
Crossroads-Hobbs-Roadrunner Transmission Line	Cost Estimate	291,600	Industry Expert Panel Transmission Provider Public Report Crossroads-Hobbs-Roadrunner 345 kV, July 3, 2023, p. 7.