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Comments of the American Wind Energy Association[1] On the 2020 National Electric Transmission Congestion Study

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On September 24, 2020, the U.S. Department of Energy ("DOE") released the 2020 National Electric Transmission Congestion Study ("Congestion Study").[2] Under Section 1221 of the Energy Policy Act of 2005 (codified as Section 216 of the Federal Power Act, at 16 USC § 824p, and referred to here as "Section 216"), DOE's development of the Congestion Study is intended to inform any exercise of its authority to designate National Interest Energy Transmission Corridors ("NIETCs"). Section 216 is a key Federal tool for ensuring that electric transmission can keep pace with growing demand for clean, reliable, and affordable energy from load-serving utilities, end-use customers, and states. As the trade association representing the U.S. wind industry, AWEA recognizes the important role of Section 216 in supporting transmission development, and appreciates the opportunity to provide input on the Congestion Study.

These comments build upon AWEA's earlier submittal[3] responding to DOE's 2018 request for comments on the procedures for conducting congestion studies.[4] Consistent with the AWEA 2018 Comments, AWEA notes several aspects of the Congestion Study that can be improved upon in any subsequent report designating NIETCs under Section 216(a)(2), most significantly the use of prospective rather than retroactive evaluation of congestion. Additionally, AWEA identifies several considerations that should inform DOE's evaluation of any project-specific application for a NIETC. AWEA believes that DOE should expressly indicate its willingness to

[1] AWEA is the national trade association representing a broad range of entities with a common interest in encouraging the deployment and expansion of wind energy resources in the United States. AWEA members include wind turbine manufacturers, component suppliers, project developers, project owners, financiers, researchers, renewable energy supporters, utilities, marketers, customers and their advocates.
[2] Request for Public Comment on the 2020 National Electric Transmission Congestion Study, 85 FR 60151 (Sept. 24, 2020) https://www.federalregister.gov/documents/2020/09/24/2020-21040/request-for-public-comment-on-the-2020-national-electric-transmission-congestion-study. The Congestion Study itself is available at http://energy.gov/oe/congestion-study.
[3] *See* Comments of the American Wind Energy Association on Procedures for Conducting Electric Transmission Congestion Studies (Nov. 1, 2018), https://www.energy.gov/sites/prod/files/2018/11/f57/AWEA%20Comments%20on%20DOE%20Congestion%20Study.pdf ("AWEA 2018 Comments").
[4] Procedures for Conducting Electric Transmission Congestion Studies, 83 FR 42647 (Aug. 23, 2018), https://www.gpo.gov/fdsys/pkg/FR-2018-08-23/pdf/2018-18229.pdf.

evaluate project-specific applications by using the forward-looking approach described in these comments to identify and address congestion.

A well-designed framework for assessing congestion on the electric transmission system must be capable of addressing the future adequacy of the nation's electric infrastructure to meet a diverse set of rapidly evolving needs. These needs include electric reliability and resilience, energy resource diversity, broader deployment new technologies in the electric sector, more efficient wholesale power markets, and determining how best to site essential electric transmission infrastructure ought to be addressed (as a policy and regulatory matter) to facilitate these goals. As in the AWEA 2018 Comments, AWEA again encourages DOE, as well as other interested Executive Branch departments and agencies, to ensure that the nation's electric transmission infrastructure is adequate to sustain the national energy policy goals that the Congress recognized in the Energy Policy Act of 2005.

These comments 1) provide input on the process for identifying congestion proposed in the Congestion Study, 2) identify several aspects from the AWEA 2018 Comments that would improve this framework, and 3) recommend evaluation considerations for project-specific NIETC applications. AWEA notes several issues that DOE should revisit, and that may affect its determination that it "has not identified transmission congestion conditions that would merit proposing the designation of National Corridors."[5]

[5] Congestion Study at vi.

I. DOE's Evaluation of Congestion Should be Improved, Both for Near-Term Consideration of Any National Interest Electric Transmission Corridors and in Subsequent Studies.

Although the Congestion Study utilized several metrics in considering transmission congestion, many of the chosen metrics are outdated, backward-looking, and insufficiently granular to provide meaningful information on actual and likely future congestion. In evaluating transmission congestion, the Congestion Study first examines transmission infrastructure investment on a national basis and by reliability region from 1996 to 2018.[6] The study then reviews the percent of time that major transmission paths were congested, and attempts to link diminishing numbers of Transmission Loading Relief (TLR) actions to transmission investment.[7] Finally, the Congestion Study shows economic transmission congestion costs from 2005 to 2017, and notes other factors (such as the increased use of natural gas) in identifying declining congestion.

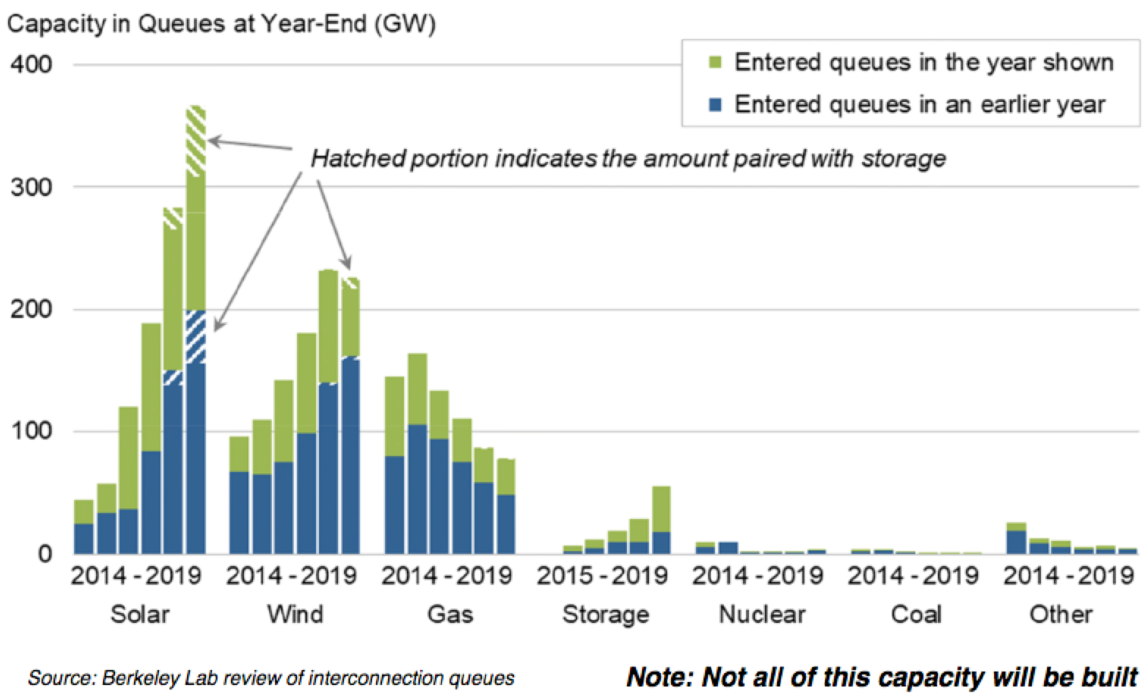
These measures are flawed in several ways, and do not correspond to the ways that grid operators evaluate and plan transmission to prevent or mitigate congestion. Most notably, DOE's analysis does not consider prospective aspects of congestion. Given the long planning and permitting processes for transmission, such an analysis must include forward-looking measures to ensure that transmission can meet both present and future needs. DOE should consider the following aspects in reevaluating its approach to congestion:

- **Prospective evaluation of congestion is essential.** First and foremost, congestion analysis must be forward-looking, and should incorporate interconnection queues to show where future generation resources, and therefore future congestion, will be. An examination of recent and current generation interconnection queues is warranted. As of the end of 2019, there were 734 GW of proposed generators waiting in interconnection queues nationwide, with almost 90% being renewable and storage resources. In calendar year 2019, 168 GW of solar and 64 GW of wind projects entered interconnection queues; these resources tend to be developed where the wind or solar resource quality is high. The U.S. EIA forecasts that wind and solar will make up over 75% of new capacity additions in 2020,[8] and these resources will likely make up the lion's share of new additions for the

[6] Congestion Study at 9-10.
[7] Congestion Study at 11-14.
[8] U.S. Energy Information Administration, *New Electric Generating Capacity in 2020 Will Come Primarily From Wind and Solar*, (Jan. 14, 2020), https://www.eia.gov/todayinenergy/detail.php?id=42495.

foreseeable future.[9] Figure 1 shows the dramatic growth of renewables in interconnection queues.

Figure 1: Capacity in Queues at Year-End by Resource Type



The recent growth in generation interconnection queues, particularly for solar and wind resources, is indicative of future congestion. While it may not be the type of congestion that has been considered in past DOE National Congestion Studies, there is an ever-growing bottleneck, with interconnection study processes unable to keep pace with demand for interconnection of new resources. Queue backlogs are increasing because interconnecting generators face high upgrade costs to resolve congestion and connect to the grid. This causes many generators to drop out of the queue, which in turn causes delays and uncertainty as other interconnection applications must be restudied. In addition, interconnecting generators can respond to likely congestion by submitting multiple interconnection applications for the same project, with different configurations and points of interconnection, further increasing queue backlogs.

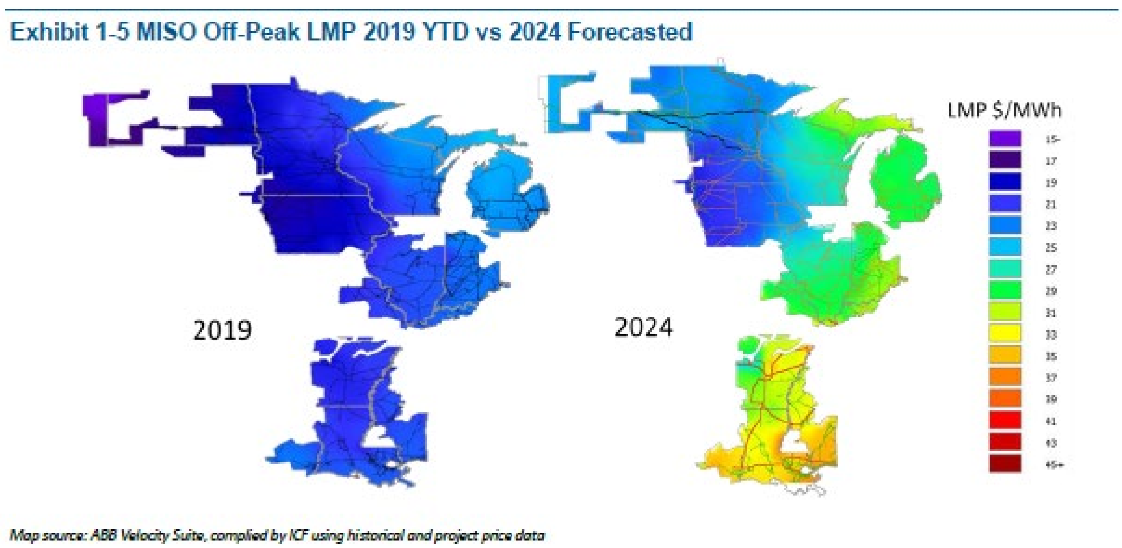
[9] *See, e.g.*, U.S. Department of Energy, *Wind Vision: A New Era for Wind Power in the United States,* Figure 3-24 at 171 (March 12, 2015), https://www.energy.gov/sites/prod/files/WindVision_Report_final.pdf.

AWEA provides detailed analysis from ICF International as Attachment A. The ICF Analysis was prepared in the winter/spring of 2020 to assess congestion issues in the central region of the United States based upon expected generation additions. The report evaluates likely transmission congestion in the Mid-Continent Independent System Operator, Southwest Power Pool, and Electric Reliability Council of Texas regions, identifies likely areas of future congestion in 2024, and identifies indicative transmission upgrades which could alleviate that congestion. The report also takes into account planned transmission expansion, and notes regarding MISO that:

> "The projection for 2024 is generally for congestion patterns to remain similar to historical trends, but the magnitude of congestion is projected to become significantly worse. This is especially true for western MISO."[10]

The ICF Analysis also identifies likely significant worsening of congestion, as reflected in LMP, from 2020 to 2024:[11]

Figure 2: MISO 2019 vs 2024 Forecasted Off-Peak LMP



Additionally, the indicative transmission upgrades in the study would be highly cost-effective; the top identified upgrades in MISO to address this future congestion would all have benefit-to-cost ratios exceeding 10:1.[12]

[10] Attachment A at 41.
[11] Attachment A at 12.
[12] Attachment A at 45.

Finally, AWEA notes that the ICF Analysis of expected congestion is also consistent with other recent approaches. For instance, mapping and analysis of MISO's interconnection queue shows both that hundreds of projects adding up to over 35,000 MW of energy were withdrawn in the past half-decade, and that "huge areas… [of] the transmission system [are] already asked to handle more power than what the grid operator advises."[13]

While AWEA does not advocate in these comments for designation of a NIETC for a particular transmission projects, these types of congestion analysis could accompany any application for a NIETC, as discussed further below.

- **Transmission investment is not a useful metric.** The Congestion Study uses transmission investment - a blunt instrument – as one of its main congestion evaluation measures. The amount spent on transmission may not link directly to congestion (or investments made to reduce or avoid it); in some cases, significant transmission investment is on local projects, or projects to address reliability or aging infrastructure that are not designed to reduce congestion as future needs shift. [14] Put "Spending more" does not equate to "spending *where it is most needed*."[15] Additionally, figures from the Edison Electric Institute indicate that transmission investment was projected to decline from 2018-2021, meaning that a key metric is trending in the wrong direction under DOE's own framework.[16]

  DOE's evaluation of congestion and constraints, and any potential NIETCs, should also include future costs and benefits to consumers, as well as

[13] *See* John Moore, *The clean energy benefits slipping through states' fingers* (Nov. 11, 2020), https://www.utilitydive.com/news/the-clean-energy-benefits-slipping-through-states-fingers/588790/.

[14] *See* Johannes P. Pfeifenberger, *Improving Transmission Planning: Benefits, Risks, and Cost Allocation* at 3 (Nov. 6, 2019) ("U.S. transmission investment is at about $20 billion/year in the past five years after steadily rising since 2000. Mostly to address reliability and local needs."), https://brattlefiles.blob.core.windows.net/files/17555_improving_transmission_planning_-_benefits_risks_and_cost_allocation.pdf. Many such smaller projects are developed outside regional transmission planning processes. *See also* Johannes P. Pfeifenberger et al., *Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value*, at 6-7, April 2019. (Between 2013 and 2017, "about one-half of the approximately $70 billion of aggregate transmission investments by FERC-jurisdictional transmission owners in ISO/RTO regions [was] approved outside the regional planning processes or with limited ISO/RTO stakeholder engagement.") While not an exact proxy, this data indicates that a significant amount of transmission spending was on local projects.

[15] *See, e.g.* https://www.transmissionhub.com/articles/2013/05/nyiso-new-york-will-need-25bn-of-investment-in-transmission-will-see-resource-shortfall-by-2021.html (significant new investment needed in NYISO); https://www.transmissionhub.com/articles/2019/03/report-30bn-to-90bn-of-incremental-transmission-investments-will-be-needed-by-2030-due-to-electrification.html (tens of billions of incremental spending in transmission investments needed by 2050 due to electrification of load).

[16] *See* https://www.eei.org/issuesandpolicy/transmission/Documents/bar_Transmission_Investment.pdf.

historical costs. Infrastructure investments are capital- intensive and require long lead times, but significantly benefits customers in many cases.

- **Historic TLR actions can inform congestion analysis, but must account for shifting market footprints and rules.** Similarly, evaluating historic congestion data on path capacity and TLR actions is not consistent with how grid operators and transmission planners evaluate congestion. The evolving footprints of regions, as well as enhanced market designs, make trend analysis over time extremely difficult and of questionable value. For example, TLRs in the Southwest Power Pool are misleading because of significant changes to that region over the evaluated period. For instance, the Energy Imbalance Service (a real-time energy market) started in 2007, followed by the Integrated Marketplace (with expanded markets) in 2014.[17] In addition, SPP's footprint increased in 2009 with the addition of the Nebraska load-serving entities, and expanded again to the Canadian border with the addition of the Western Area Power Administration/Basin Electric Power Cooperative Integrated System in 2015.[18] As a result, time series TLR data for SPP does not provide meaningful data to draw conclusions, as the market design and footprint significantly changed within the window evaluated by the Congestion Study. Additionally, as noted below, Section 216 does not limit DOE's evaluation of congestion and constraints solely to historic measures; historic TLR data, while relevant, should not be overstated, and should be just one data category that informs DOE's NIETC evaluation process.

- **Congestion costs do not appear to be falling.** The Congestion Study does not account for recent trends in congestion costs. DOE's data ends in 2017, yet congestion costs were on average higher for the period 2018-2019. Specifically, the six RTOs reported congestion costs of $5.080 billion in 2018 and $3.535 billion in 2019, for an average of $4.308 billion.[19] This is higher than RTO congestion costs in 2016 ($3.769 billion) and 2017 ($4.197 billion). Although costs fell from 2018 to 2019, the increasing trend from 2016-2018 does not support a conclusion that congestion costs are falling.

- **DOE Should Consider a Range of Congestion Metrics and Costs.** Many types of congestion are typically not accounted for under the congestion cost metrics included in DOE's report. For example, the Congestion Study only focuses on congestion costs within RTOs, and does not quantify congestion between RTOs, between RTOs and non-RTO areas, or in non-RTO areas.

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[17] *See* https://spp.org/markets-operations/integrated-marketplace/.
[18] *See* https://www.spp.org/newsroom/press-releases/western-basin-heartland-join-southwest-power-pool/.
[19] *See Transmission Congestion Costs in the U.S. RTOs*, Jesse Schneider, Grid Strategies LLC (Aug. 14, 2019; updated Nov. 12, 2020), https://gridstrategiesllc.com/2019/09/17/transmission-congestion-costs-in-the-u-s-rtos/.

Even within RTOs, some of the biggest constraints to efficient and effective power system operations are not existing flowgates, but rather the lack of transfer capacity between two points or adjacent systems that have little to no transfer capacity. The metrics used in the Congestion Study understate actual congestion within RTOs by focusing on existing flowgates and not capturing congestion between points that currently lack transfer capacity.

Additionally, transmission congestion results in many types of societal costs that are not accounted for in the metrics used by DOE. However, MISO,[20] SPP,[21] and others[22] have accounted for costs, including:

- Line losses are higher on congested and lower-voltage transmission lines relative to less congested, higher-voltage alternatives.
- Congested transmission limits the ability to share planning and operating reserves over larger areas, which increases capacity costs and production costs.
- Transmission congestion can drive renewable deployment into regions with lower quality resources, requiring greater expense to produce the same amount of generation.

DOE should be prepared to evaluate congestion across a range of measures, and should take a similarly holistic approach to the associated costs and benefits of congestion relief.

- **The generation mix is rapidly shifting towards renewables, which will shape congestion patterns.** Evaluating congestion reductions, which DOE notes has been in large part due to past coal-to-natural gas switching, provides little indication of what congestion patterns will look like as Variable Energy Resources ("VERs") proliferate. DOE's Congestion Study should incorporate prospective modeling identifying where congestion is likely to occur in the future. In addition to DOE conducting its own modeling, this can include compiling work done by regional planning entities, national laboratories, and other experts. For example, stakeholder-driver regional transmission planning processes typically conduct production cost modeling that identifies congestion under a range of future resource scenarios.

[20] MISO, "MTEP17 MVP Triennial Review," (September 2017), https://cdn.misoenergy.org/MTEP17%20MVP%20Triennial%20Review%20Report117065.pdf
[21] SPP, "The Value of Transmission," (January 2016), https://www.spp.org/documents/35297/the%20value%20of%20transmission%20report.pdf
[22] See, for example, The Brattle Group, "The Benefits of Electric Transmission," (July 2013), https://cleanenergygrid.org/uploads/WIRES%20Brattle%20Rpt%20Benefits%20Transmission%20July%202013.pdf

DOE has the opportunity to improve upon the Congestion Study, and has the resources and authority to evaluate any potential NIETC under this improved framework. Given the long lead time to get high-voltage transmission approved and constructed, DOE National Congestion Studies should look prospectively and include comprehensive systematic assessments, which could be facilitated by DOE with key support by stakeholders of the bulk power system. It would seem appropriate for DOE to leverage recent renewable integration studies, and/or other power systems modeling efforts such as the North American Energy Resilience Model (NAERM,) to perform independent analyses to facilitate interregional planning, including between the existing Interconnections.

Additionally DOE's Congestion Study should also include a range of maps produced by grid operators and others. For example, most RTO Independent Market Monitor reports include heat maps of annual average Locational Marginal Prices, which reveal the location of congestion, and quantify how it harms consumers. DOE should also include maps produced by RTOs showing available transmission transfer capability.[23]

Finally, AWEA notes that the Congestion Study proposes to change the scope of future studies to an "ongoing evaluation of issues affecting the capacity of the Nation's transmission system to serve critical national interests," including "details regarding potential threats; data and predictions on resulting impacts; tools required to model multiple infrastructures; and details concerning the coordination of numerous utilities and stakeholders involved in regional and national-scale energy system operations."[24] Although transmission adequacy and security are worthy issues for DOE to address, AWEA submits that the statutory scheme of Section 216 requires that DOE *specifically* evaluate electric transmission congestion and constraints to inform its determination of whether NIETCs might be necessary; accordingly, AWEA urges that national security threat and resilience analyses should be conducted separately from future Congestion Studies.

[23] For example, *see* https://cdn.misoenergy.org/GI-Contour_Map108143.pdf.
[24] Congestion Study at 36.

II. DOE Can and Should Consider Multiple Factors in Evaluating Electric Transmission Congestion and Constraints.

A. The History and Text of Section 216 Give DOE Significant Latitude in Considering Whether to Designate NIETCs.

The Congestion Study does not identify any necessary corridors – in large part by focusing its analysis on a limited number of retrospective, geographically broad factors, as discussed above. While AWEA does not seek designation of a specific corridor at this time, DOE's approach is not required by the statute. In enacting the statutory scheme of Section 216, Congress sought to provide a federal solution to the lack of 'long-haul' transmission being developed. Congress identified "state regulatory approval [that] delays siting of new transmission lines by many years" as a major culprit.[25] This new federal authority was needed to help overcome "[s]iting challenges, including lack of coordination among States, [that] impede the improvement of the electric system."[26] As a result, Section 216 lists five broad topics the Secretary may consider in developing NIETCs. Once identified, projects within the corridors can utilize a federal approval and siting process – a potentially powerful tool for addressing the growing need for transmission to reliably support the transition to renewable energy resources.

As indicated in the AWEA 2018 Comments, DOE is not limited to these factors. In considering how to move forward on the report required under Section 216(a)(2), as well as on any project-specific corridor proposal, DOE should examine all of the relevant factors. In designating a NIETC, Section 216(a)(2) allows DOE to designate a corridor in any area "experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers." Section 216(a)(4) permits the Secretary to consider whether:

(A) "The economic vitality and development of the corridor, or the end markets served by the corridor, may be constrained by lack of adequate or reasonably priced electricity;

(B)
  (i) Economic growth in the corridor, or the end markets served by the corridor, may be jeopardized by reliance on limited sources of energy; and
  (ii) a diversification of supply is warranted;

(C) The energy independence of the United States would be served by the designation;

(D) The designation would be in the interest of national energy policy; and

[25] H.R. REP. NO. 109-215 at 171 (2005).

[26] S. REP. NO. 109-78, at 8 (2005) (statement of Sen. Pete Domenici, Chairman of the Senate Committee on Energy and Natural Resources). In another statement, Domenici said that the act would "streamline the permitting of siting for transmission lines to assure [sic] adequate transmission." 150 CONG. REC. S3732 (daily ed. Apr. 5, 2004) (statement of Sen. Domenici).

(E) The designation would enhance national defense and homeland security."

This framework allows DOE to consider additional relevant information in evaluating congestion and identifying any needed NIETCs, beyond the factors discussed in the 2020 Congestion Study. Since its first congestion study in 2007, DOE has interpreted "constraints or congestion that adversely affects consumers" under section 216(a)(2) broadly. DOE found this was *not* limited to price impacts; for instance, adverse effects exist when constraints impede the ability of renewable energy developers to offer environmental and economic benefits to consumers.[27] DOE has also recognized its authority to designate corridors in the absence of *present* congestion, so long as a constraint, including the absence of transmission capacity, is likely to have adverse effects including hindering the development of desirable generation,[28] meeting Federal or State policy goals, or denying some transmission users or customers the benefit of their preferred transactions – such as the desire to purchase renewables.[29]

Geographic areas with high renewable penetration but little access to customers due to a lack of transmission clearly fit within this standard. Similarly, areas facing overloaded generator interconnection queues as a result of insufficient transmission face a "constraint . . . that adversely affects consumers" by driving up the cost of obtaining clean energy for customers, including large corporate and industrial energy users. Moreover, Congress' decision to allow DOE to consider a range of factors suggests that the lack of available transmission connecting high-renewable-potential areas with load centers could warrant a NIETC designation. Bringing additional renewable energy to load will help diversify energy supply and will be critical to achieving "national energy policy." Although this term is not defined in EPAct 2005 or elsewhere in the Federal Power Act, it should encompass (but may not be limited to) Presidential determinations on targets for emissions reductions, deployment of renewable energy, and Federal energy procurement goals.

AWEA further notes that several aspects of 216(a)(4) allow DOE to consider *potential* future changes – including whether economic vitality and development, or end markets, "*may* be constrained by lack of adequate or reasonably priced electricity", and whether economic growth "*may* be jeopardized by reliance on limited sources of energy." Had Congress required DOE to make a finding that these consequences were present at the time of each Congestion Study, it clearly could have used phrases such as "is constrained" or "is jeopardized." Similarly, the statute does not limit DOE's economic

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[27] *See* National Electric Transmission Congestion Report, 72 Fed. Reg. 56,992, 57,000 (Oct. 5, 2007)("2007 Congestion Report"). *See also* Avi Zevin, Sam Walsh, Justin Gundlach, and Isabel Carey, *Building a New Grid Without New Legislation: A Path to Revitalizing Federal Transmission Authorities* at 33 (Oct. 2020; publication forthcoming 2021), https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3727699.
[28] 2007 Congestion Report at 57,000; Zevin *et al.* at 33-34.
[29] 2007 Congestion Report at 57,004; Zevin *et al.* at 33-34.

analysis to the scope of a corridor; instead, it *specifically* allows for consideration of economic vitality, development, and growth in the end markets served by the corridor, as well as within the corridor. DOE's past interpretation of Section 216, as advanced in the 2007 Congestion Study, is that it has the ability to use its authority to designate NIETCs to head off incipient risks, and has broad statutory authority to consider a wide range of benefits. AWEA urges DOE to continue to act consistent with this interpretation, which it has not publicly retracted or revised.

Despite these broad statutory criteria, DOE has not identified a NIETC since 2007.[30] AWEA noted in 2018, and continues to note here, a number of future risks that DOE's authority under Section 216 could help to resolve, all of which are consistent with the statutory framework. The AWEA 2018 Comments identified several key areas germane to DOE's statutory criteria under 216, all of which remain a valid basis (individually or in combination) for designating NIETCs, or for considering project-specific applications – and which are already part of the record (supplemented by the instant comments):

- **Resilience and Reliability: "**Resilience and reliability of the nation's electric grid are bolstered with investment in transmission system upgrades. A significant benefit of reducing congestion, through the expansion of transmission, is that it allows the grid to operate equally reliably with fewer power plants, by allowing the sharing of planning and operating reserves among neighboring power systems. Reduced planning reserve needs are a significant benefit of transmission. New, strategically located transmission projects can allow grid operators to use imports and exports from neighboring power systems to help meet peak demand, saving billions in dollars per year by not having to build as many power plants for planning reserves. Interregional transmission projects also provide geographic diversity, which contributes to resilience and reliability."[31]

- **Customer savings:** "Investments in expansion of electric transmission infrastructure result in pass through benefits to consumers in the form of lower costs of power. **…** Investments in transmission provide a high return on investment for customers, according to a report published by Southwest Power Pool, investments made in the region from 2012-2014 had, on average, a benefit-to-cost ratio of 3.5 to 1. This means that for every dollar invested in transmission, $3.50 in value is delivered to the region over the long lifespan of the project."[32]

[30] *See generally* 2007 Congestion Report.
[31] AWEA AWEA 2018 Comments at 4.
[32] *Id*. at 5-6, citing https://www.spp.org/value-of-transmission/.

- **Planned future generation:** "DOE should also consider the size and delays in generation interconnection queues, particularly MISO and SPP, as an indication of a lack of sufficient transmission capacity to promote economic outcomes. Delays in interconnection queues may also present resource diversity and resilience issues. In addition, curtailment across the various wholesale markets should be included in the study, examining how curtailment could be resolved with increasing transmission capacity in a region. Curtailment has far reaching impacts on the cost of electricity, ability to maintain a diverse resource portfolio mix, ability to meet public policy goals, and resilience of the overall system."[33]

- **Attainment of state and federal policy goals at least cost:** "Additional metrics should be included in the criteria for designation of corridors, which goes beyond the traditional definitions of "congestion" or "constraint." DOE should update criteria for the designation of NIETCs to reflect the current needs of the grid, including the ability to achieve public policy goals, bolster national security by supporting reliability and resilience, and reduce queue delays and curtailment. Insufficient transmission capacity can make it difficult for utilities and other load serving entities to meet state or federal public policy goals to which they are otherwise subject. Without modernization or expansion of the grid, achievement of the various public policies, whether renewable energy portfolios, clean energy standards, or others governing greenhouse gas emission, will be difficult if not impossible… DOE should identify and examine existing federal, state, and local policies, determine what those will require in terms or new supply resources, and determine the amount and general location of transmission capacity that will be needed to deliver output from those resources to customers. Aging transmission facilities, outdated control technology, or infrastructure that is insufficient to deliver electric power from diverse resources and locations… heighten concerns about the reliability and resilience of the electric system and threatens national security in the face of extreme weather, physical attack, or other contingencies. These and other contingencies should also be part of the congestion analysis, considering how a lack of transmission capacity can dramatically limit the number and availability of remedies or defenses with which to meet such challenges when states and locales need them most."[34]

Although the 2020 Congestion Study does not directly reflect these factors, AWEA notes that they individually and collectively remain salient, as reflected by subsequent studies.

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[33] Id. at 8.
[34] Id at 7.

B. Significant Recent Evidence Shows the Need for Transmission Development, Consistent with the Statutory Scheme of Section 216.

In the two years since DOE received comments on its congestion study procedures, substantial additional data has emerged supporting the need for a holistic evaluation of congestion, and the potential benefits of using NIETCs to ensure transmission development. For instance, a recent study from Americans for a Clean Energy Grid ("ACEG") identifies the need for increased transmission development to complement growing renewable generation. [35] The ACEG Study makes clear the need for additional transmission development, and "confirms that large-scale transmission expansion is critical for maintaining affordable and reliable electric service under any scenario for future renewable costs or carbon emissions."[36] The ACEG Study examined the need for transmission in the Eastern Interconnection under four scenarios, and found transmission upgrades would be required under any of those scenarios:

> "Many findings are intuitive. For example, scenarios with larger emissions reductions result in a larger transmission expansion. The scenarios with high wind deployment also generally drive somewhat larger transmission expansion than the high solar deployment cases, as shown in the figure below. This chart shows GW-miles; for example, a 500-mile transmission line that delivers 2 GW provides 1,000 GW-miles of transmission capacity. The figure below makes clear that, regardless of future trends in carbon emissions or wind and solar costs, large amounts of new high-capacity transmission will be required.[37]"

The ACEG study, like the Congestion Study, recognizes the increase in transmission investment since 2005. However, while the ACEG study identifies an increase in transmission investment,[38] it clarifies that most of that investment has occurred at the local or intrastate level.[39] Despite the inclusion of NIETC authority in law, this has not yet resulted in the development of "long-haul" interstate transmission Congress envisioned when creating Section 216.

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[35] Christopher Clack, et al., *Consumer, Employment, and Environmental Benefits of Electricity Transmission Expansion in the Eastern U.S.,* Americans for a Clean Energy Grid, 26 (October 2020), https://cleanenergygrid.org/wp-content/uploads/2020/10/Consumer-Employment-and-Environmental-Benefits-of-Transmission-Expansion-in-the-Eastern-U.S..pdf ("ACEG Study").
[36] *Id.* at 26.
[37] *Id.* at 22.
[38] NIETC Study, page 10.
[39] JOHANNES P. PFEIFENBERGER ET AL., THE BRATTLE GRP., COST SAVINGS OFFERED BY COMPETITION IN ELECTRIC TRANSMISSION: EXPERIENCE TO DATE AND THE POTENTIAL FOR ADDITIONAL CUSTOMER VALUE 4 (2019), https://brattlefiles.blob.core.windows.net/files/15987_brattle_competitive_transmission_report_final_with_data_tables_04-09-2019.pdf.

Additionally, the ACEG study also found significant rate savings would accrue to customers as a result of transmission investment:

> "[T]he average electric bill rate [would] decrease[] by more than one-third, from over 9 cents/kWh today to around 6 cents/kWh by 2050. This would save a typical household more than $25 per month or $300 per year at current electricity consumption levels,[40] and significantly more as electricity consumption increases to displace gasoline consumption in cars and natural gas consumption for heating. Transmission primarily provides this benefit by accessing low-cost, high-quality wind and solar resources, reducing the generation cost component that currently comprises over two-thirds of consumers' electric bills. The cost of transmission averages around a quarter cent per kWh ($2.7/MWh) over this period, accounting for only 3.6% of a consumer's total electric bill, even as transmission drives total electric bills down."[41]

Similarly, the recent Interconnections Seam Study from the National Renewable Energy Laboratory shows that significant transmission expansion and the creation of a national network will be essential in incorporating high levels of renewable resources, all while returning more than $2.50 for every dollar invested in many scenarios.[42] The study found a need for 40-60 million MW-miles of AC and up to 63 million MW-miles of DC transmission for one scenario. The US has approximately 150 million MW-miles in operation today. Access to low-cost generation will always result in consumer savings, but absent transmission infrastructure, those savings will fail to reach many consumers. Using forward-looking studies to identify corridors will increase access to these low-cost resources.

Geographic constraints on certain types of generation are another important aspect for DOE to consider. The Congestion Study indicate that one factor reducing congestion costs has been the transition to more natural gas fired generation.[43] As the price of natural gas decreased from 2005 to 2018, natural gas generation displaced coal fired plants. Coal fired plants tended to be located further from delivery points, and the change to closer natural gas generators contributed to a decrease in congestion costs over the same time period.

Increased deployment of renewable generation will not mirror that trend. Many desirable locations for citing wind energy have been identified, but they are located

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[40] https://www.eia.gov/tools/faqs/faq.php?id=97

[41] Christopher Clack, et al., *Consumer, Employment, and Environmental Benefits of Electricity Transmission Expansion in the Eastern U.S.,* Americans for a Clean Energy Grid, 6 (October 2020).

[42] National Renewable Energy Laboratory, *Interconnections Seam Study* (Oct. 2020), https://www.nrel.gov/analysis/seams.html.

[43] Congestion Study at 18-19.

further away from the load than existing natural gas plants.[44] Because proximity affects congestion, DOE should consider past as well as future trends on the location of generation.[45] As noted above, one essential source of information on planned renewable development is regional interconnection queues.[46] The presence of significant wind capacity is an indication of planned development, and corresponds with potential future congestion constraints. By examining where planned wind generation will be located, DOE can consider applications for NIETCs that will enable generation buildout without increasing congestion costs. Similarly, DOE should consider where transmission limitations have resulted in the withdrawal of projects, many of which could provide significant economic benefits through inexpensive electricity.[47]

In short, Section 216 provides DOE significant discretion on how to evaluate congestion and constraints, as well as future risks and broad economic benefits, in determining whether NIETCs are appropriate. DOE should make clear that it will consider this range of benefits in the report required under Section 216(a)(2), as well as in consideration of any project-specific corridor – discussed in the next section.

III. DOE Should Make Clear that it Will Consider Project-Specific Corridors, and Should Further Specify the Information Required of Applicants.

Although DOE's authority to designate NIETCs is broad, AWEA believes that the most effective use of this authority is in relation to specific, targeted proposals for individual transmission projects that meet the statutory criteria. In soliciting comments on procedures for the Congestion Study in 2018, DOE stated that it would "continue to produce the triennial studies required by the statute, and would also respond, perhaps separately, to requests for the preparation of project-specific congestion studies or the designation of related National Corridors."[48]

In 2018, DOE proposed that individual project sponsors seeking NIETC designation should supply:

[44] Christopher Clack, et al., *Consumer, Employment, and Environmental Benefits of Electricity Transmission Expansion in the Eastern U.S.,* Americans for a Clean Energy Grid, at 30 figures 28-31(October 2020). https://cleanenergygrid.org/wp-content/uploads/2020/10/Consumer-Employment-and-Environmental-Benefits-of-Transmission-Expansion-in-the-Eastern-U.S..pdf
[45] Interconnections Seam Study, page 19.
[46] See AWEA AWEA 2018 Comments at App'x A.
[47] *See* https://www.utilitydive.com/news/the-clean-energy-benefits-slipping-through-states-fingers/588790/ (noting that 278 wind, solar, and battery projects in MISO, with nameplate capacity of more than 35,000 MW, were withdrawn between 2016 and 2020; while not all withdrawals are directly attributable to congestion, many projects withdrew after their transmission upgrade costs were determined).
[48] 83 FR 42648.

a. Data or studies confirming the existence in a specific geographic area of transmission constraints or congestion adversely affecting consumers;
b. Data or studies confirming that proposed transmission project(s) would ease the congestion and its adverse impacts on consumers;
c. Information showing how a National Corridor should be bounded in order to be relevant to the proposed transmission project(s); and
d. Information showing why it would be in the national interest for the Department to intervene in a subject area that is normally subject to state jurisdiction.

In its 2018 Comments, AWEA supported this proposal, and noted that "Developers are best equipped to identify the areas that are most crucial to building transmission. Under such an approach, the developer should bear the burden of demonstrating that the proposed corridor meets the criteria in section 216(a)(4) of the Federal Power Act. The result of this amended process would be narrower corridors because developers would propose corridors that better align with the routes of specific projects."[49]

The Congestion Study changes these questions somewhat, and indicates that proponents of a transmission project should now respond to the following:

> "1. Where transmission congestion is occurring, or is very likely to occur, in a specific geographic area, with adverse impacts on consumers;
> 2. How the proposed transmission project would alleviate the congestion;
> 3. How the proposed National Corridor would be bounded, and the rationale for those boundaries; and,
> 4. In this particular case, the reason it would be in the national interest for the Secretary of Energy to intervene in a matter that is normally wholly under the jurisdiction of the affected state(s)."[50]

AWEA believes that questions 1-3 are generally appropriate, and will assist in evaluation of any NIETC application(s). Question 2 could be improved by adding the phrase from the 2018 Procedure NOPR, that applicants should show how the project would alleviate the congestion "*and its adverse impacts on consumers*," as this is consistent with the framework of Section 216.

However, AWEA recommends that DOE entirely replace its current Question 4, and instead insert the following opportunity for applicants to demonstrate consistency with the statutory criteria:

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[49] AWEA 2018 Comments at 10.
[50] Congestion Study at 2.

4. *How the proposed NIETC designation would:*

    - *Relieve any constraint on the economic vitality and development of the corridor, or the end markets served by the corridor, caused by lack of adequate or reasonably priced electricity;*
    - *Ensure that economic growth in the corridor, or the end markets served by the corridor, is not jeopardized by reliance on limited sources of energy; and that a diversification of supply is warranted;*
    - *Serve the energy independence of the United States;*
    - *Be in the interest of national energy policy; and*
    - *Enhance national defense and homeland security.*[51]

Congress has established a detailed framework for DOE to consider in designating any NIETC, which (as detailed above) grants DOE significant latitude. If an applicant can demonstrate that a proposed project meets the statutory criteria, this provides a complete basis for designation of a corridor and federal involvement, if necessary. Accordingly, AWEA's proposed Question 4 would serve the same purpose as the version of Question 4 in the Congestion Study, but would provide greater clarity for applicants.

AWEA appreciates the opportunity to provide comments on the Congestion Study, and urges DOE to take this input into account in evaluating any project-specific corridor applications and in any future Congestion Studies.

Sincerely,

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[51] 16 USC § 824p(a)(4).

Assessment of Congestion and Transmission Upgrades in SPP, MISO, and ERCOT

April 24, 2020

Submitted to:

American Wind Energy Association

Submitted by:
ICF Resources, LLC

IMPORTANT NOTICE:

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Acronyms

AECI	Associated Electric Cooperative
ALTW	Alliant West
AMIL	Ameren Illinois
APC	Adjusted Production Cost
ATB	Annual Technology Baseline (NREL)
AWEA	American Wind Energy Association
CAGR	Compound Annual Growth Rate
COMED	Commonwealth Edison Company
CRR	Congestion Revenue Rights (ERCOT)
EI	Eastern Interconnect
ERCOT	Electric Reliability Council of Texas
IPSAC	Inter-regional Planning Stakeholder Advisory Committee
ISO	Independent System Operator
LMP	Locational Marginal Price
LP&L	Lubbock Power and Light
LRGV	Lower Rio Grande Valley
MEC	Mid-American Energy
MISO	Midcontinent Independent System Operator
MTEP	MISO Transmission Expansion Plan
MVP	Multi-Value Project (MISO)
NEPA	National Environmental Policy Act
NPPD	Nebraska Public Power District
NREL	National Renewable Energy Laboratory
NSP	Northern States Power (Xcel)
OKGE	Oklahoma Gas and Electric
OTP	Otter Tail Power
PRB	Powder River Basin
PTC	Production Tax Credit
RPG	Regional Planning Group (ERCOT)
SECI	Sunflower Electric Power
SPP	Southwest Power Pool
SPS	Southwestern Public Service
WECC	Western Electricity Coordinating Council
WFEC	Western Farmers Electric Cooperative
WR	Westar Resources
YTD	Year-to-Date (in this report: 10/20/2019)

1. Executive Summary

ICF Resources LLC, a subsidiary of ICF, was engaged by the American Wind Energy Association ("AWEA" or the "Client") to assess congestion pricing in the MISO, SPP, and ERCOT organized power markets with a focus on impact to wind generators. ICF's scope included a review of historical congestion patterns and causes, a forward-looking congestion analysis using SCED modeling, and a high-level evaluation of indicative transmission upgrades in each market to relieve projected congestion.

ICF undertook this analysis first in Q4, 2019. As of Q4, 2020, ICF confirms the study results are still valid and relevant at a summary level. The transmission upgrades identified are indicative of potential projects in each market with significant congestion impact.

ICF's key findings are summarized and presented in this section.

1.1 Summary of Findings

By 2024, assuming a continued renewable buildout and currently-approved transmission projects, congestion in major wind-producing areas is generally found to worsen across ERCOT and MISO compared to recent historical levels. However, mild improvements are forecasted for SPP.

In each market, transmission upgrades are identified that are expected to relieve market congestion, meet benefit/cost planning criteria[1], and therefore likely to be approved using adjusted production cost savings. ICF estimates that by implementing the upgrades identified for the top three transmission projects in each market, cost to serve load could be reduced by a total of $60 million at high benefit/cost ratios.

The identified upgrades are most effective in ERCOT, where specific pain points with low potential upgrade costs are found to contribute to widespread congestion. These constraints center on the ability to move low-cost renewable power out of the West zone.

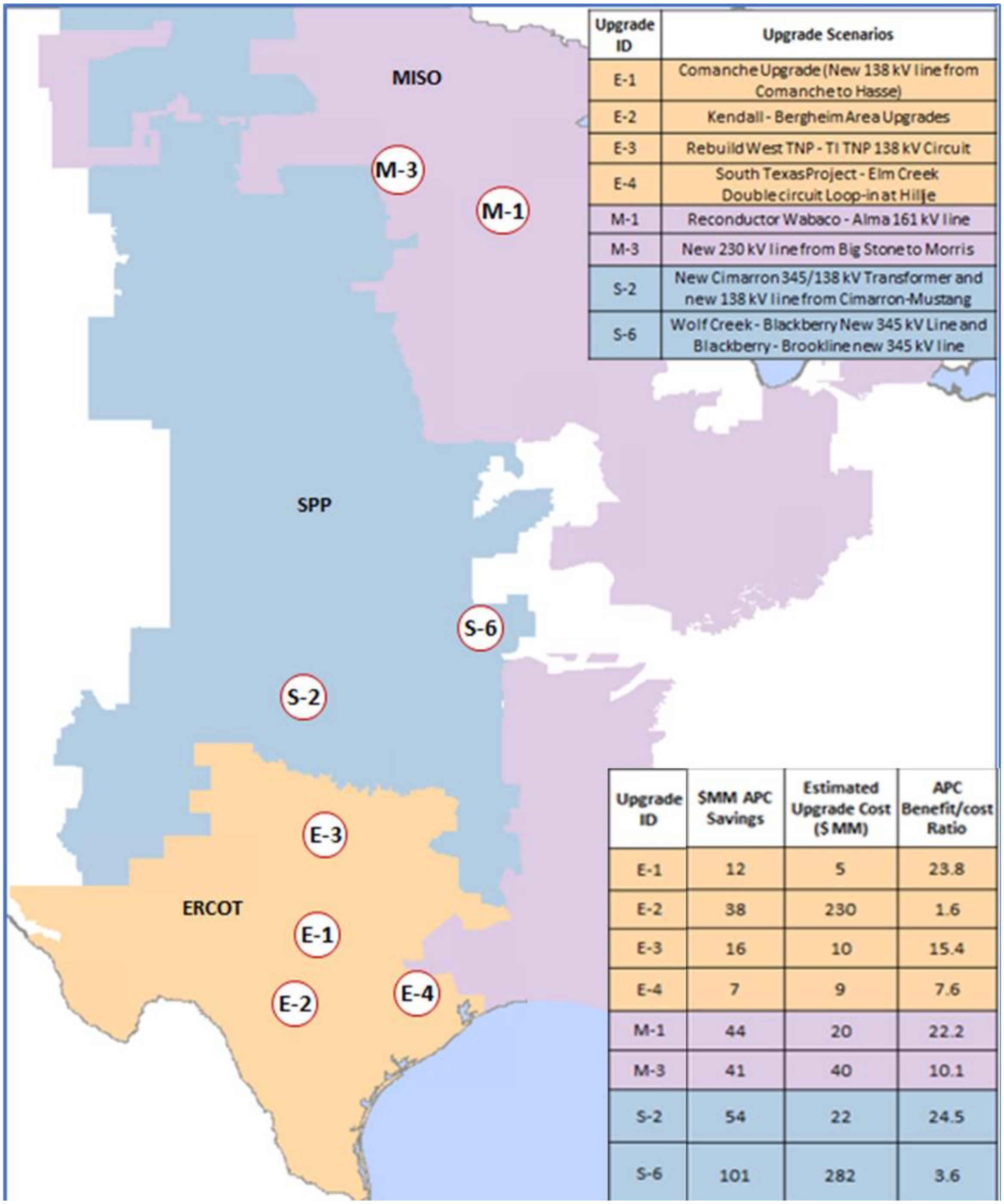
In contrast, congestion in MISO is found to be more persistent due to widely distributed congestion across low-voltage networks throughout the market, and long transmission distances contributing to high loss components in LMP formation. We believe a renewed buildout of high voltage lines is needed to significantly change congestion patterns. Nevertheless, ICF identified several indicative low/medium voltage upgrades that are beneficial to the market (relative to their cost).

In SPP, we find that congestion in SPP South area does not change substantially from recent historical levels, which have been meaningfully improved by recent transmission builds. However, we identify both low- and high-voltage projects in critical areas that improve congestion in SPP and also significantly improve transfer capacity to MISO.

The most effective upgrades identified in all three markets and associated benefits are shown in Exhibit 1-1 below. The historical and projected prices/congestion patterns, the potential upgrades assessed and key findings for individual markets are explained in the upcoming sections.

[1] ICF performed adjusted production cost savings and benefit/cost ratio assessment for a single study year (2024) only.

Exhibit 1-1 Summary of Transmission Upgrades Assessed in Three Markets



Upgrade ID	Upgrade Scenarios
E-1	Comanche Upgrade (New 138 kV line from Comanche to Hasse)
E-2	Kendall - Bergheim Area Upgrades
E-3	Rebuild West TNP - TI TNP 138 kV Circuit
E-4	South Texas Project - Elm Creek Double circuit Loop-in at Hillje
M-1	Reconductor Wabaco - Alma 161 kV line
M-3	New 230 kV line from Big Stone to Morris
S-2	New Cimarron 345/138 kV Transformer and new 138 kV line from Cimarron-Mustang
S-6	Wolf Creek - Blackberry New 345 kV Line and Blackberry - Brookline new 345 kV line

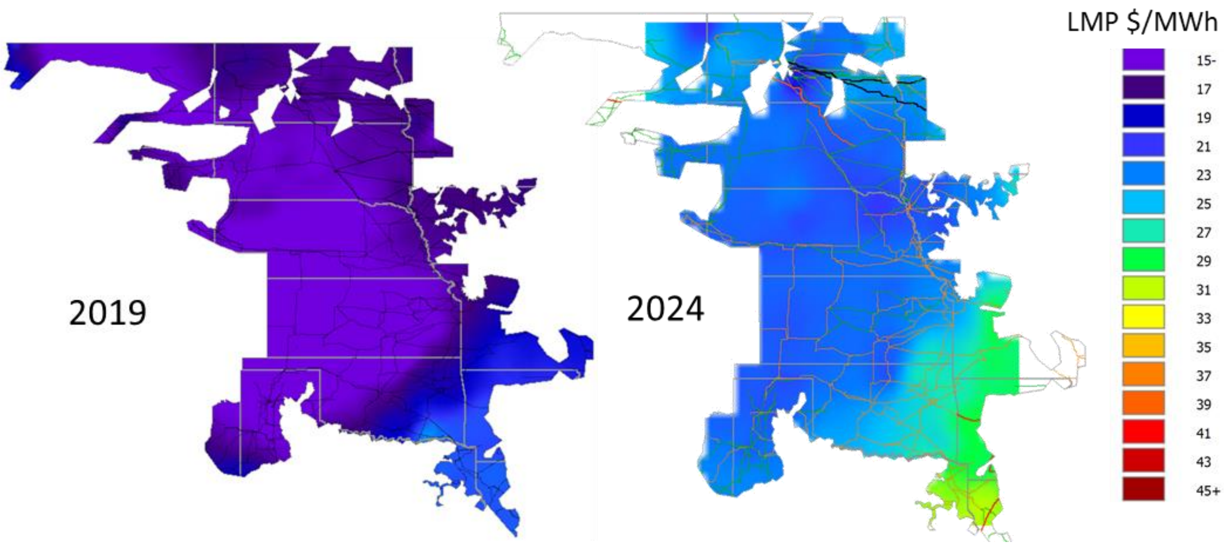
Upgrade ID	$MM APC Savings	Estimated Upgrade Cost ($ MM)	APC Benefit/cost Ratio
E-1	12	5	23.8
E-2	38	230	1.6
E-3	16	10	15.4
E-4	7	9	7.6
M-1	44	20	22.2
M-3	41	40	10.1
S-2	54	22	24.5
S-6	101	282	3.6

Map source: Created by ICF Using ABB Velocity Suite

1.2 SPP

A comparison of off-peak LMP patterns in SPP for 2019 YTD historical and 2024 projected is shown in Exhibit 1-2. Major high-voltage transmission upgrades in southwest SPP came in service in 2017/2018, most notably Woodward PST, Woodward-Tatonga-Mathewson second circuit, and Iatan-Stranger Creek 345kV lines, improving congestion meaningfully across the market. By 2019, congestion patterns form an interface separating load areas in the southeastern part of the SPP market, including export seams with MISO, from the wind-producing regions in the TX/OK Panhandles and the Great Plains states. Relevant binding constraints include the area around Cleveland substation near Tulsa and the Cimarron transformer outside of Oklahoma City. No large-scale new transmission is planned by 2024, though small improvements are implemented around the grid.

Exhibit 1-2 SPP Off-Peak LMP 2019 YTD vs 2024 Projected



Map source: ABB Velocity Suite, compiled by ICF using historical and projected price data

By 2024, the Base Case includes 9.7 GW of new wind buildout and 3.9 GW of new solar in SPP. Since the overall topology of the grid (location of wind, transmission constraints, etc.) remains largely the same, the same congestion patterns from 2019 largely persist in our model, but the number of binding hours at critical constraints increases. Despite this, nodal basis between northwestern SPP and SPP South Hub stays largely flat or improves slightly. This is because the buses that make up SPP South Hub (scattered mostly around central OK) straddle this broad congestion interface in 2019, leading to an average price that is higher than nodal prices in wind-producing areas. However, by 2024, new wind builds around the area of SPP South Hub contribute to lower hub prices. Additionally, low-voltage upgrades around Oklahoma (including several projects upgrading 69kV lines to 138kV in WFEC territory) "soften" the congestion interface as seen in the maps above and reduce separation between SPP South Hub buses and wind nodes further west. The increase in binding constraints separates wind regions from nodes that are largely not part of SPP South Hub.

Upgrades Studied

In the 2019 ITP process, SPP approved two new major 345kV builds on basis of economics: between Wekiwa and Sooner substations in northeast Oklahoma, and between Wolf Creek and Blackberry substations in southeast Kansas. These are not projected in-service until at least 2026. However, ICF studied the impact of the Wolf Creek-Blackberry line in our 2024 case (as a sensitivity case and not included in the Base Case above). Our analysis, which differs from SPP's[2], finds the project (in isolation, and in 2024 vs 2026) marginally economic at 0.8 benefit/cost ratio, mainly because of price depression in Oklahoma. Additionally, we find that resulting congestion is highly sensitive to the location of new renewable builds, particularly in Missouri, and therefore small differences in the renewable buildout assumptions between ICF and SPP may be impactful. Nevertheless, in our Base Case, with Wolf Creek-Blackberry tested in 2024 we find that congestion moves downstream from the Blackberry endpoint to Morgan, Jasper, and other substations (see Exhibit 1-3 below and chapter 3.3 for more detail).

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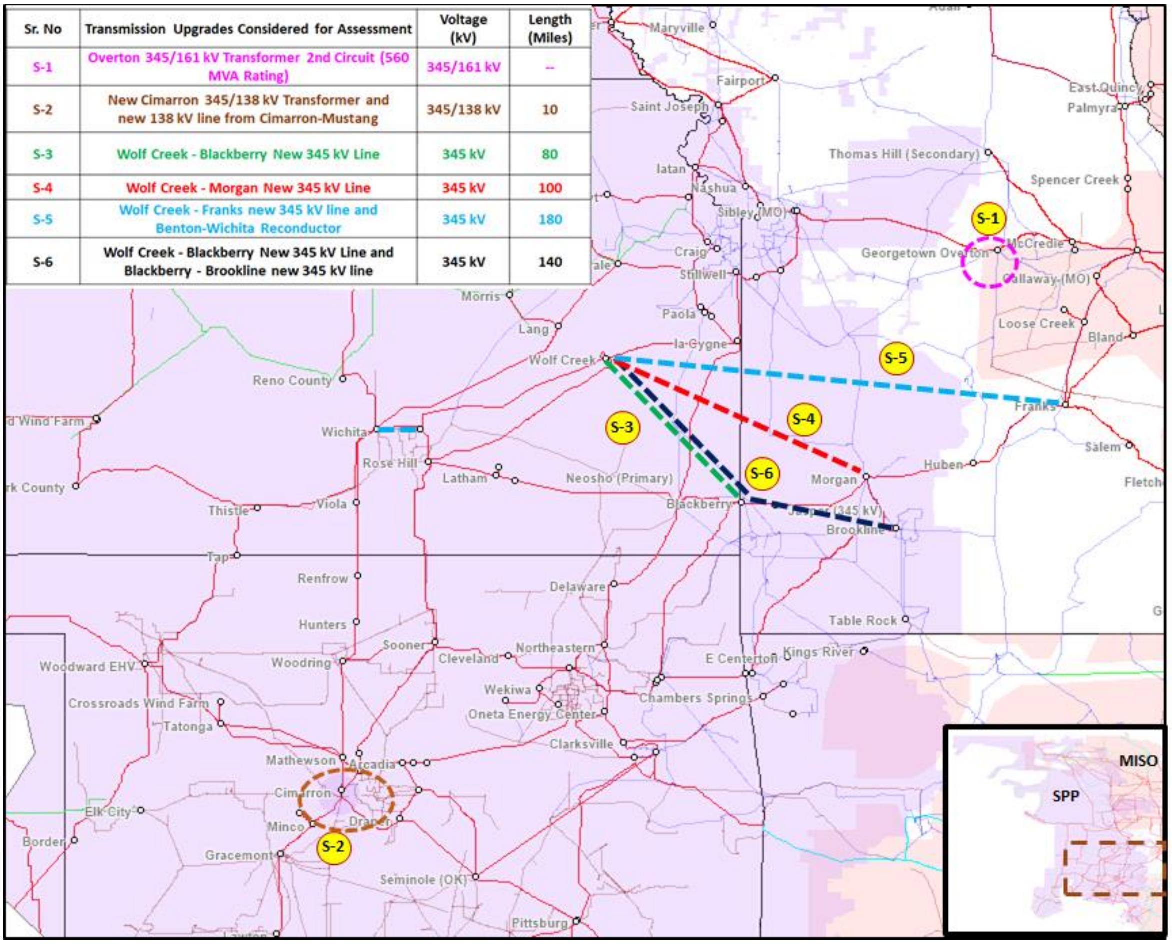
[2] For example, SPP awards bonus points for building new 345kV lines, runs multiple future buildout cases, considers reliability needs in addition to economics simultaneously, and consolidates multiple upgrades into portfolio solutions when evaluating effectiveness. The 2019 ITP was released after the start of ICF's evaluation, and therefore we have not included in the model the other reliability and economic projects identified therein. However, for economic projects, the single largest factor in SPP's evaluation is benefit/cost as measured by APC. This is consistent with ICF's approach in the present study. We have also prioritized use of a standardized approach for all three markets for consistency.

Exhibit 1-3 Upgrades Studied in SPP

Sr. No	Transmission Upgrades Considered for Assessment	Voltage (kV)	Length (Miles)
S-1	Overton 345/161 kV Transformer 2nd Circuit (560 MVA Rating)	345/161 kV	--
S-2	New Cimarron 345/138 kV Transformer and new 138 kV line from Cimarron-Mustang	345/138 kV	10
S-3	Wolf Creek - Blackberry New 345 kV Line	345 kV	80
S-4	Wolf Creek - Morgan New 345 kV Line	345 kV	100
S-5	Wolf Creek - Franks new 345 kV line and Benton-Wichita Reconductor	345 kV	180
S-6	Wolf Creek - Blackberry New 345 kV Line and Blackberry - Brookline new 345 kV line	345 kV	140



Please note: *projects labeled S-4 and S-5 were exploratory and not included in the final study. S-3 shows the path of the approved Wolf Creek-Blackberry line. Map source: ABB Velocity Suite*

Accordingly, we studied an additional project that continues the line downstream, extending past Blackberry to Brookline substation. Adding a 345kV line from Blackberry-Brookline saves $50MM in adjusted production costs (APC)[3] to the market. Also, we find that the line allows much greater transfer to MISO, creating meaningful congestion relief in other seams areas (most notably the area around Overton substation) which are heavily congested in the Base Case.

We find new transmission a preferable solution not only to the directly intended constraints, but also to upgrading the Overton area separately. We tested an upgrade at Overton transformer that increased transfer capacity, but it showed negative benefit/cost ratios for both MISO and SPP, since it mostly raised prices in load areas in SPP and lowered prices for generators in MISO. In contrast, the combined Wolf Creek-Blackberry-

[3] Adjusted production costs are a measure of market efficiency and often used in interconnected markets (such as SPP and MISO in the eastern interconnect) for estimating project benefits. APC is defined as the cost to serve load, plus variable costs of generation, minus the revenues paid to generators.

Brookline project shows positive benefit/cost ratio for MISO and SPP each. Increased transfers between SPP and MISO at the Morgan-Franks-Brookline network further south is shown to be preferable to both markets compared to increased transfers at Overton.

Finally, we also studied upgrades at the Cimarron substation east of Oklahoma City as a gateway for SPS wind from the twin Panhandles and New Mexico into SPP load centers. We find that adding a 138/345kV transformer at the existing 345kV Cimarron substation, and connecting a new 138kV line from there to Mustang substation was an effective solution, showing high benefit/cost ratio. The upgrade saves the market $22MM in adjusted production costs. A summary of all upgrades studied and their effects is shown in Exhibit 1-4 below.

Exhibit 1-4 Summary Results of SPP Upgrades

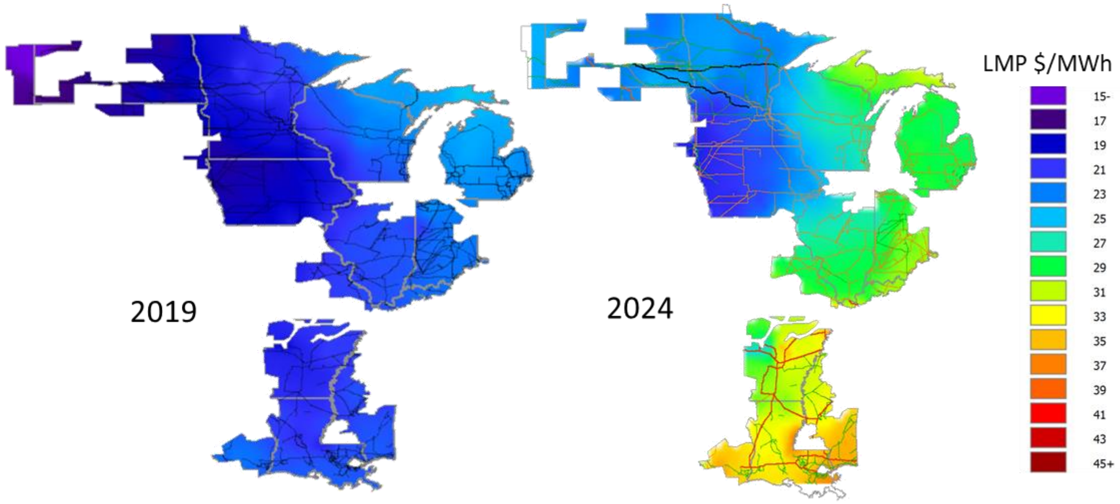
Upgrade ID	Upgrade	$MM Adj. Production Cost Savings	APC Benefit/cost Ratio for SPP	APC Benefit/cost Ratio for MISO	Est. Project Cost $MM
S-1	Overton 345/161 kV Transformer 2nd Circuit @560 MVA	-1	-1.2	-4.5	7
S-2	New Cimarron 345/138kV Transformer and new 138kV line Cimarron-Mustang	54	24.5	0.8	22
S-6	Blackberry-Brookline new 345kV assuming Wolf Creek-Blackberry	89	7.4	12.7	120

Note: Cimarron upgrade shaded green for benefit/cost in MISO despite being lower than 1 because MISO would not pay for the upgrade but would experience some modest economic benefits; there is not projected to be an affected system cost imposed.

1.3 MISO

A comparison of off-peak LMP patterns in MISO for 2019 historical and 2024 projected is shown in Exhibit 1-5 below. Similar to SPP, major new 345kV lines came online across MISO over 2015-2019 as part of the Multi-Value Projects (MVP) initiative which have reduced nodal basis to major hubs compared to historical levels. Additionally, new wind builds in MISO were slow compared to other areas: only around 4.5 GW was added between 2015-2019 (for example, ERCOT added 7 GW in a market that is about 2/3rd of MISO's size over the same period). As a result, 2019 YTD has yielded the lowest nodal basis for wind plants in the study period. However, because of the geographic size of the market (contributing to high loss components in LMP formation) and high concentration of wind in a relatively small area around Iowa and southern Minnesota, nodal basis across MISO is still higher compared to other markets.

Exhibit 1-5 MISO Off-Peak LMP 2019 YTD vs 2024 Forecasted



Map source: ABB Velocity Suite, complied by ICF using historical and project price data

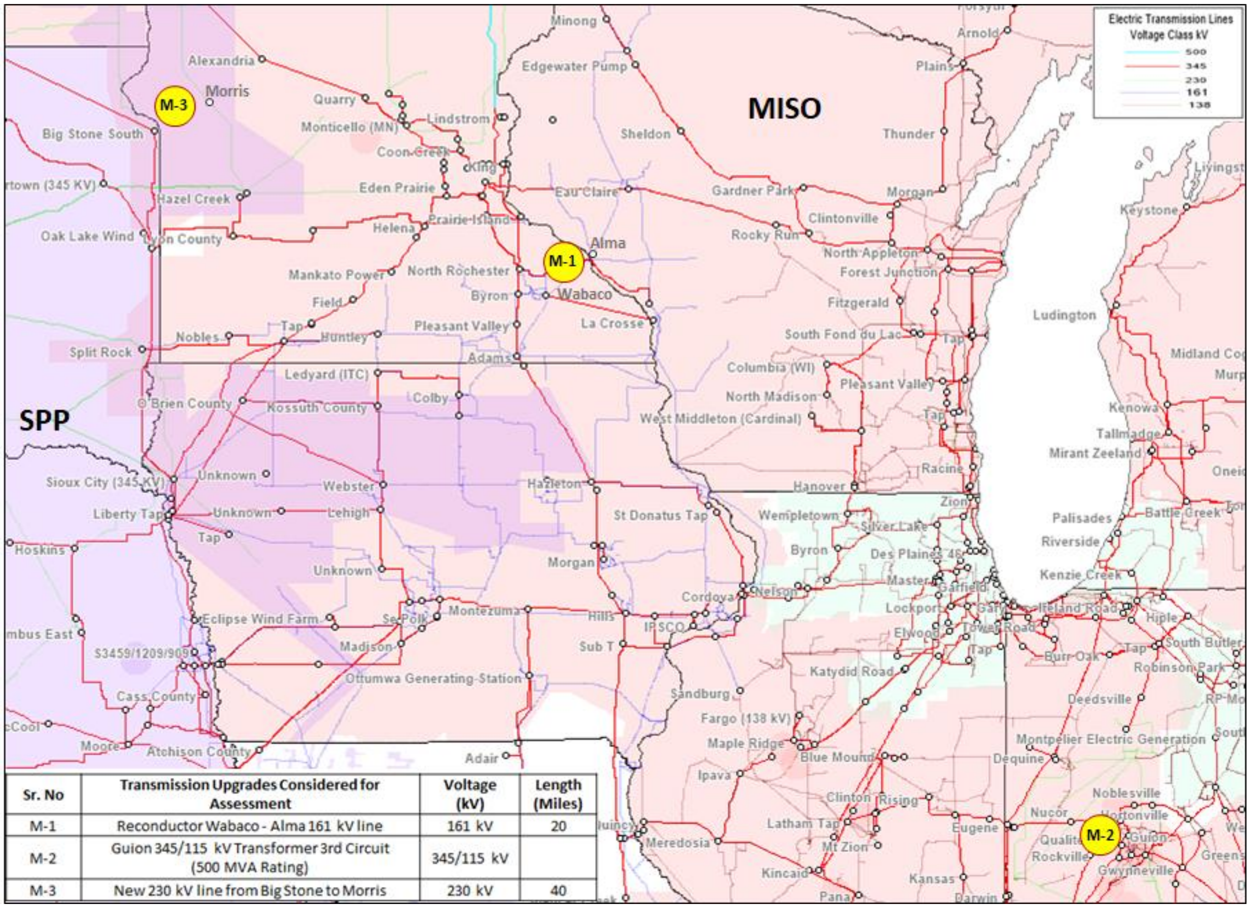
By 2024, the Base Case adds 12.3 GW of wind and 8.7 GW of solar across MISO. About 60% of the new wind is west of the Mississippi River. The results show nodal basis becoming significantly worse across the market and especially in western Iowa and Minnesota. Apart from the MISO North/South boundary, the congestion results from distributed constraints throughout the MISO network, largely on low-voltage lines, as opposed to a small number of well-defined chokepoints. This reduces the potential for any one transmission upgrade to have a large effect, since congestion is less concentrated. Within MISO North, congestion is primarily a west-to-east phenomenon both historically and in the 2024 projection.

The most identifiable congestion area generally brackets the IA/MN wind pocket, in terms of congested seams with SPP to the west and congested interfaces with MISO load centers and PJM-COMED to the east. The four constraints with the highest cost in MISO-North in 2024 are Fairport-Hickory Creek, Overton transformer (each SPP seams in Missouri), Wabaco-Alma (in southeast MN), and Big Stone-Browns Valley (border of SD and MN).

Upgrades Studied

ICF tested upgrades at key SPP seams and reported the results in the SPP section. In MISO, ICF tested the next two most binding constraints, both located in the northwest wind belt.

Exhibit 1-6 Upgrades Assessed in MISO West



Sr. No	Transmission Upgrades Considered for Assessment	Voltage (kV)	Length (Miles)
M-1	Reconductor Wabaco - Alma 161 kV line	161 kV	20
M-2	Guion 345/115 kV Transformer 3rd Circuit (500 MVA Rating)	345/115 kV	
M-3	New 230 kV line from Big Stone to Morris	230 kV	40

Map source: ABB Velocity Suite

The Rochester to Wabaco 161kV reconductor in 2023 was an important project identified in MTEP 2018 based on economics. However, our modeling for 2024 indicates that the upgrade is only partially effective because the next section of the line, Wabaco-Alma, becomes the most congested element in western MISO. Takeaway capacity is much greater from Alma substation, which connects to several other high voltage lines, than Wabaco, which only exists as a midpoint on a 161kV line. Continuing the reconductoring effort from Wabaco further to Alma (project 1 in Exhibit 1-6 above) is relatively inexpensive and is shown in our modeling to be both highly beneficial for consumers ($19MM in savings to load for annualized project cost of $2MM).

Second, we tested upgrades at the second-most congested point in western MISO, around Big Stone substation at the eastern edge of South Dakota. The 345kV line that exists from Ellendale through Big Stone South to Brookings is the result of two major MVP projects completed in 2017 and 2019. However, the 230kV network that connects at Big Stone becomes congested with the increase in power along the new higher voltage network. We tested a project connecting Big Stone to Morris on the 230kV network to bypass the contingency with Browns Valley, which was shown to reduce adjusted production costs in the market by $41MM in 2024.

We also looked into eastern MISO and tested an upgrade at Guion transformer, which is the most frequently binding and costliest constraint in Indiana. Adding a new 345/115kV circuit to the transformer removed the binding constraint and was shown to have benefits to the market and to wind producers, but the net effect for both was much smaller than expected. We do not find any obvious downstream constraints becoming binding in place of Guion transformer after upgrade that could be included to improve the economics; rather, congestion patterns adjust slightly and mute the total impact (though the project shows a high benefit/cost ratio because of its low cost). Based on both historical and projected congestion in eastern MISO, we find that this may be characteristic of the region. A summary of all upgrades studied, and their effects is shown in Exhibit 1-7 below.

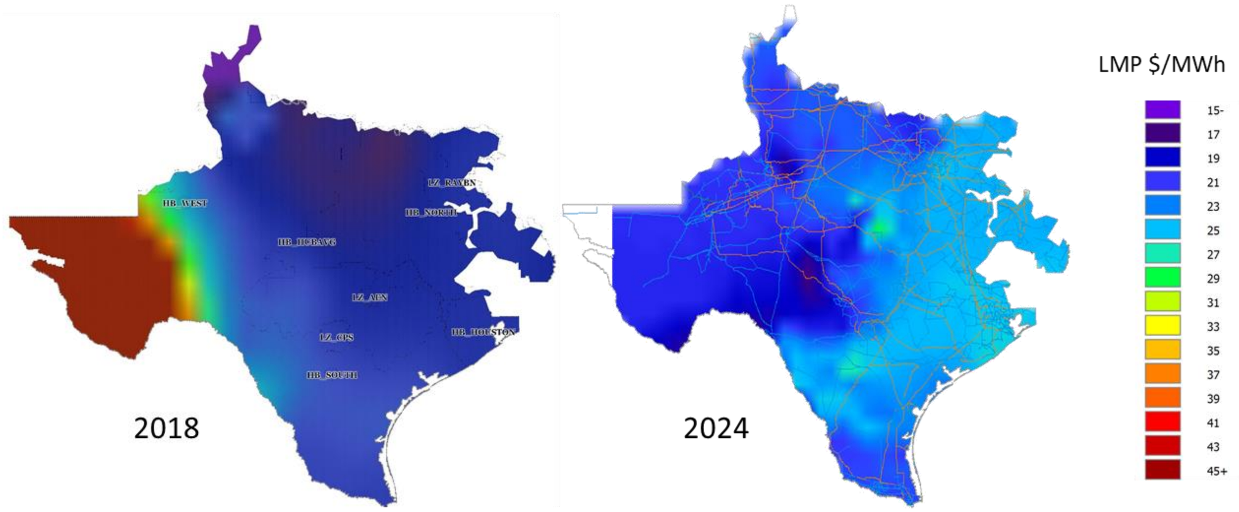
Exhibit 1-7 Summary Results of MISO Upgrades

Upgrade ID	Upgrade	$MM Adj. Production Cost Savings	APC Benefit/cost Ratio for MISO	Est. Project Cost $MM
M-1	Wabaco-Alma 161kV Reconductor	44	22.2	20
M-2	Guion Transformer 345/115 3rd circuit (500 MVA)	16	26.0	6
M-3	Big Stone – Morris new 230kV line	41	10.1	40

1.4 ERCOT

A comparison of off-peak LMP patterns in ERCOT for 2018 and 2024 projected is shown in Exhibit 1-8. By 2024, major upgrades in the Far West and the Panhandle will bring these extreme areas much closer to parity with the rest of ERCOT West. The Far West is a rapidly growing demand center because of the extractive industries in the Permian Basin; new 345kV circuits in 2020 and 2021 will connect this demand with the rest of the grid, benefitting prices across the rest of ERCOT West. The Panhandle will integrate Lubbock Power and Light (LP&L), which will become the only demand in the Panhandle in 2021. Transmission upgrades associated with the LP&L integration will redefine the current export interface and allow much greater transfer of wind power to the rest of the market. Additionally, a series of low-voltage upgrades around Dallas in North zone will improve import capability for excess wind power in the West.

Exhibit 1-8 ERCOT Off-Peak LMP 2018 vs 2024 Forecasted



Note: 2018 shown for ERCOT whereas 2019YTD shown for other markets for this graphic because our uniform scale bar used for all markets does not highlight low enough prices to illustrate actual trends in 2019. The congestion patterns for 2018 and 2019 are similar, but with slightly higher prices in 2018 that better reveal the contours and trends. Map source: ABB Velocity Suite; Compiled by ICF using historical and forecasted prices.

Despite this, the addition of 11.9 GW of wind and 8.3 GW of solar, largely in the West[4], will cause the interior of the ERCOT West zone to fragment into multiple congestion regions and put ERCOT West at a more severe discount to the rest of the market. In particular, the areas near the geographic center of the market will become highly congested due to the emergence of Comanche Switch-Comanche Tap, constraints at Kendall 345kV, and several constraints within West. Additionally, because ERCOT West Hub buses are relatively spread out throughout the zone, plants within West zone may find themselves at increasing discount to West Hub. Separation between all four ERCOT hubs increases significantly. The additional renewables and large transmission upgrades currently approved in ERCOT by 2024 change congestion patterns significantly: only one of the top 15 constraints from either 2018 or 2019 still make the top 15 list in 2024.

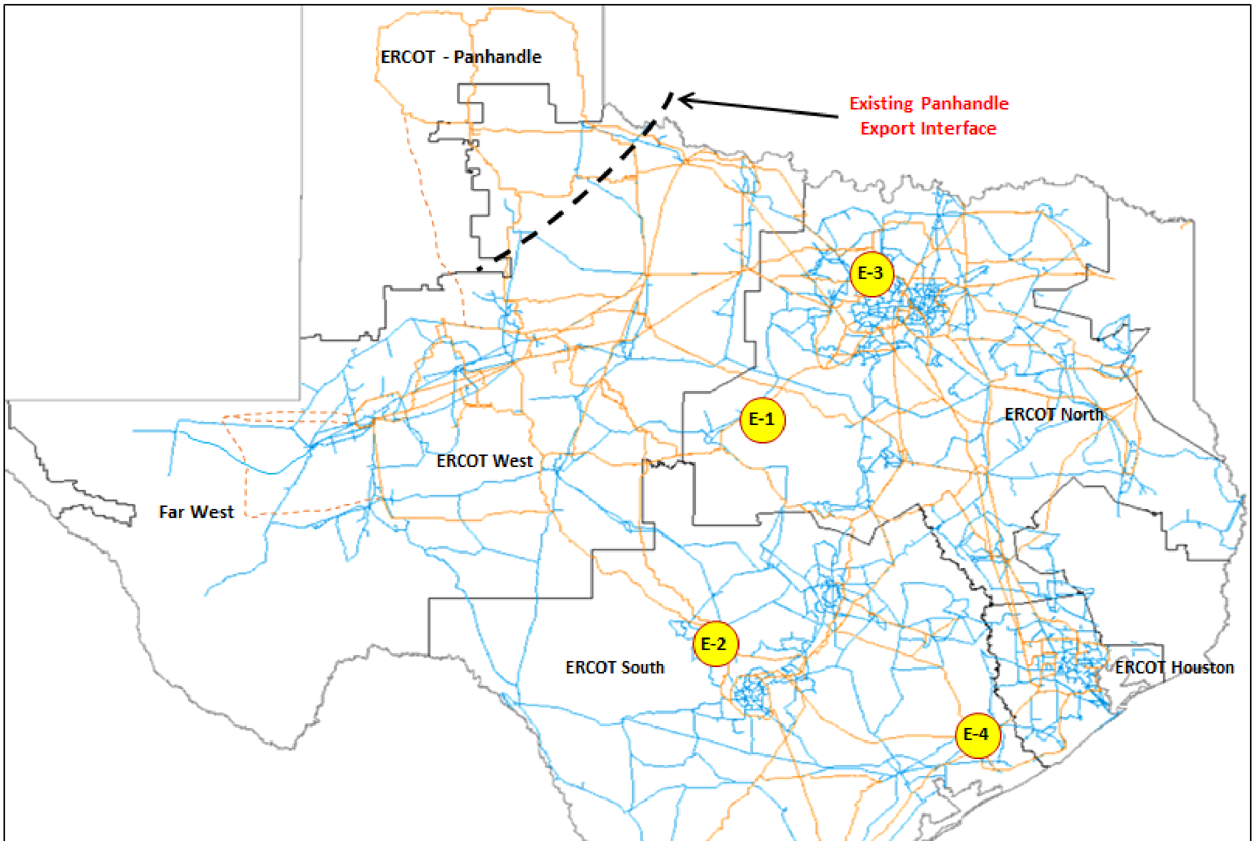
Upgrades Studied

In ERCOT, ICF finds many low-cost solutions that effectively address these new, major constraints in the market. While the 2024 Base Case shows widespread congestion, it is largely the result of individual chokepoints rather than grid-wide weakness[5]. In most cases, upgrades local to the identified constraint are effective and do not simply push congestion around to other areas. We believe many will likely be addressed by ERCOT prior to a situation like the 2024 Base Case occurring.

[4] ICF only added 793 MW of wind in the Panhandle based on known transmission constraints and lack of further upgrades planned after 2021. If more wind is added, projected Panhandle congestion would worsen and create a need/opportunity for additional transmission.

[5] Q4, 2020 update: ICF notes that in in Oct 2020 (approx. one year after the study was undertaken), ERCOT implemented a West Export GTC that represents a stability limit across all 345kV lines from West zone to other zones. Individual constraints, some of which correspond to monitored lines in this GTC, still exist however and ICF models show them to be significantly binding in addition to the GTC.

Exhibit 1-9 Upgrades Tested in ERCOT



Sr. No	Transmission Upgrades Considered for Assessment	Voltage (kV)	Length (Miles)
E-1	Comanche Upgrade (New 138 kV line from Comanche to Hasse)	138 kV	1
E-2	Kendall - Bergheim Area Upgrades: Add a new 345 kV circuit from Kendall - Hill Country. Upgrade Kendall - Bergheim 345 kV and Bergheim - Devils Hill 138 kV circuits. And add a second Bergheim auto transformer.	345 kV/138 kV	--
E-3	Rebuild West TNP - TI TNP 138 kV Circuit	138 kV	5
E-4	South Texas Project - Elm Creek Dbckt Loop-in at Hillje	345 kV	--

Map source: ABB Velocity Suite

ICF started with two upgrades that had already been studied by ERCOT but not yet approved. First, in the Kendall area in ERCOT South zone, we re-tested a package of upgrades totaling $230MM affecting several circuits. ERCOT's analysis in 2018 showed that the package did not meet benefit/cost criteria, but since then renewable capacity in the interconnection queue has grown significantly. The results for 2024 indicate higher production cost savings and a benefit/cost ratio of 1.6. Overall, the projected net benefits for wind generators in ERCOT total $38MM and the market also saves $38MM in annual production costs[6].

Second, we evaluated the South Texas-Elm Creek loop-in at Hillje near the intersection of South and Houston zones. This project was recommended in ERCOT's 2018 Regional Transmission Plan (RTP) based on economics

[6] Unlike in interconnected markets which use APC, ERCOT uses production cost (sum of variable costs of generation) as the benchmark for measuring project benefits. Like APC, this is also a measure of efficiency.

but has not advanced; a similar version of this upgrade was recently recommended again in the 2019 RTP. Our analysis confirms a strong benefit/cost ratio.

Third, we evaluated a short new 138kV line from Comanche to Hasse. Our modeling finds this upgrade to be an effective solution for the local constraint and only slightly shifts congestion patterns at other constraints. The benefit/cost ratio is very high due to the low cost of the upgrade.

Finally, we tested a rebuild of the 138kV line from West TNP-TI TNP around Dallas. Following a series of already-approved upgrades to the low-voltage network in the area, this line shows up as the most binding constraint as renewable capacity grows in the West and import pressure grows. This is the costliest constraint in the market in 2024 and is effectively addressed with our re-build; other constraints increase as a result, but relatively little compared to the congestion relieved. The upgrade easily meets benefit/cost criteria.

Exhibit 1-10 Summary Results of ERCOT Upgrades

Upgrade ID	Upgrade	$MM Production Cost Savings	Production Benefit/cost for ERCOT	Est. Project Cost $MM
E-1	Comanche-Hasse 138kV New Line	12	23.8	5
E-2	Kendall-Bergheim Area Upgrades	38	1.6	230
E-3	Rebuild West TNP-TI TNP 138kV Circuit	16	15.4	10
E-4	South Texas Project - Elm Creek Dbckt Loop-in at Hillje	7	7.6	9

2. Overview of Methodology

ICF used ABB's PROMOD for final modeling of future market prices and congestion trends. PROMOD is a nodal, hourly SCED model that captures the impact of binding transmission constraints and their impacts on congestion and price formation. We used outputs from PROMOD including nodal prices at all nodes in each market, transmission constraint binding hours and congestion costs, and system production cost metrics.

However, ICF also used several other models as part of the setup to PROMOD. First, we used our proprietary IPM production cost model to forecast economic new builds and retirements in each market based on fundamental economic factors such as capital costs (see below). Second, after determining supply/demand outlook, we used GE PSLF power flow model to determine new transmission constraints to monitor in PROMOD. Inputs to the modeling were derived in collaboration with AWEA. ICF started with our latest internal Base Case assumptions for each market and made minor adjustments where noted with an asterisk. Our approach is generally as follows:

Exhibit 2-1: Methodology for Modeling Input Assumptions

Input Parameter	Methodology	Comments/Exceptions
Natural Gas Prices	For 2024 in each market, we use ICF's latest fundamentals-based gas price model, GMM, to project monthly prices at 130+ zones around North America. For reference, the forecast shows Henry Hub prices of $3.23/MMBtu in 2024.	n/a
Demand	In general, use the ISO's latest demand forecasts	For ERCOT, we revert to 10-yr historical CAGR after 2023
Transmission Expansion	Approved projects only*	We exclude two projects in ERCOT that are currently not approved but in ICF Base Case to study the impact
Near Term (2020-2022) New Builds	Based on projects at an advanced stage in the interconnection queues, e.g. PG6.9(1) criteria in ERCOT, IA signed in SPP, etc.	Occasional exceptions for individual plants when more information is publicly available
New Builds 2022+ and Retirements	Based on economics projected in ICF's zonal production cost model, IPM. Relevant input assumptions listed below:	Included extra wind builds beyond economically projected based on feedback from AWEA (see paragraph following table)*
New Plant Capital Costs	NREL 2019 ATB low case* using regionalization from EPA v6	
Tax Credits	ITC and PTC assumed allowed within a 4-year safe-harbor window. Current phase-out schedule maintained, no extension assumed	
Renewable Mandates	Enforce currently-approved state and utility RPS programs	Little binding effect in ERCOT, SPP, or MISO by 2024

Based on ICF's gas price assumptions, currently approved RPS targets, and other inputs, once the tax credit period fully expires[7], we project a very modest amount of new renewable builds for 2023-2024. For the purposes of this study, we included an extra 1.6 GW of wind in ERCOT, 1.2 GW in SPP, and 1.1 GW in MISO by 2024.

The above inputs are used to create the Base Case projections for 2024. Once set, ICF investigated possible transmission upgrades in each market for impact on wind merchant revenues and overall project economics. ICF selected new transmission projects to test based on the following general principles[8]:

- Addresses a notable constraint in the 2024 Base Case
- Focused on moving low-cost renewable power to load centers
- Evaluate projects spread across different geographic areas of each market

In a few cases, we tested several iterations of possible upgrades based on initial results in the modeling. We consider these findings of value in addition to the upgrades that showed promise, and therefore include them in our results. After identifying possible upgrades, ICF tested implementation in PROMOD.

We evaluated each transmission upgrade based on its benefit/cost ratio. This gives an indication of the project's likelihood of success based on economic criteria in ISO transmission planning. This has two components:

Benefits: To measure benefits in 2024, we used the change in Adjusted Production Cost (APC) before and after the upgrade. APC is calculated as the cost to serve load (price times load quantity at all load buses) minus generator gross margin (nodal price times generation quantity at all generator buses, minus variable costs). In ERCOT, reflecting the market's transmission planning process and isolated grid, we used production cost instead, which is only the sum of all variable cost of generation.

APC and production cost are measures of market efficiency. Reductions in APC will result in consumer savings, because it indicates that energy prices for load are being reduced and/or the market will effectively attract new, efficient generation.

Levelized cost: Since we did not model long-term grid conditions, we used a 10% levelization factor on the all-in capital cost to estimate cost in 2024. To estimate capital cost, we used generic costs based on voltage, distance, equipment upgrades etc. as follows:

- New line costs are assumed as $2MM/mile for new 345kV line and $1MM/mile for the 230kV and below lines.
- Reconductoring low-voltage transmission is assumed $1MM/mile.
- Transformer costs are estimated at $12k/MVA (based on 345/115 kV transformer).

[7] Q4, 2020 update: in 2020, after finalization of the study, PTC benefits were modestly extended

[8] **Please note:** this is an explorative exercise with a large theoretical problem set. ICF is not guaranteeing that the projects evaluated are the best possible options. Follow-up studies, including closer evaluation of technical/feasibility aspects and sensitivity case / robustness testing, for key projects identified here is recommended.

2.1 Comparison with ISO Methodologies

The three markets in question use differing methodologies to evaluate new transmission. Replicating each markets' planning processes would be difficult or impossible, since the markets may require a joint consideration of reliability needs, evaluation of portfolio solutions rather than one-by-one analysis, use of multiple planning scenarios under a stepwise approach, and in many cases a degree of art or discretion, among other factors. In this scope we are not attempting to *predict* exactly which projects the ISOs will approve in the future; rather we seek to identify a limited number of potential projects that could benefit the grid and pass economic tests.

However, this study is set up to provide conclusions that would be useful in the context of each ISO's planning process for economic projects. Therefore, ICF's methodology is generally consistent with the process used by each of the ISOs. ICF's analysis is based on what we identify as the "common denominators" in each for evaluating economic projects, and uses a single, consistent methodology for each market (the only difference being use of adjusted production cost as the benefit metric in SPP and MISO while using production cost as the benefit metric in ERCOT). We believe that if our inputs were used in each of the ISO's transmission planning processes, they would yield broadly similar conclusions.

Our input assumptions, especially our renewable buildout used in the reference case, differ from recent studies run by each ISO. Most notably, we are including higher renewable buildout in the near term than the ISOs[9].

For example, ERCOT only includes near-term projects that have made significant progress in the interconnection queue, and nothing further. For example, zero builds are included between 2021-2024. With the very large amount of renewables in the interconnection queue and continuing tax credits for renewables, we view this as an extremely conservative assumption. This leads us to very different conclusions on economic transmission than ERCOT. Likewise, we include more new renewables than either of SPP's scenarios (see below discussion of the SPP process).

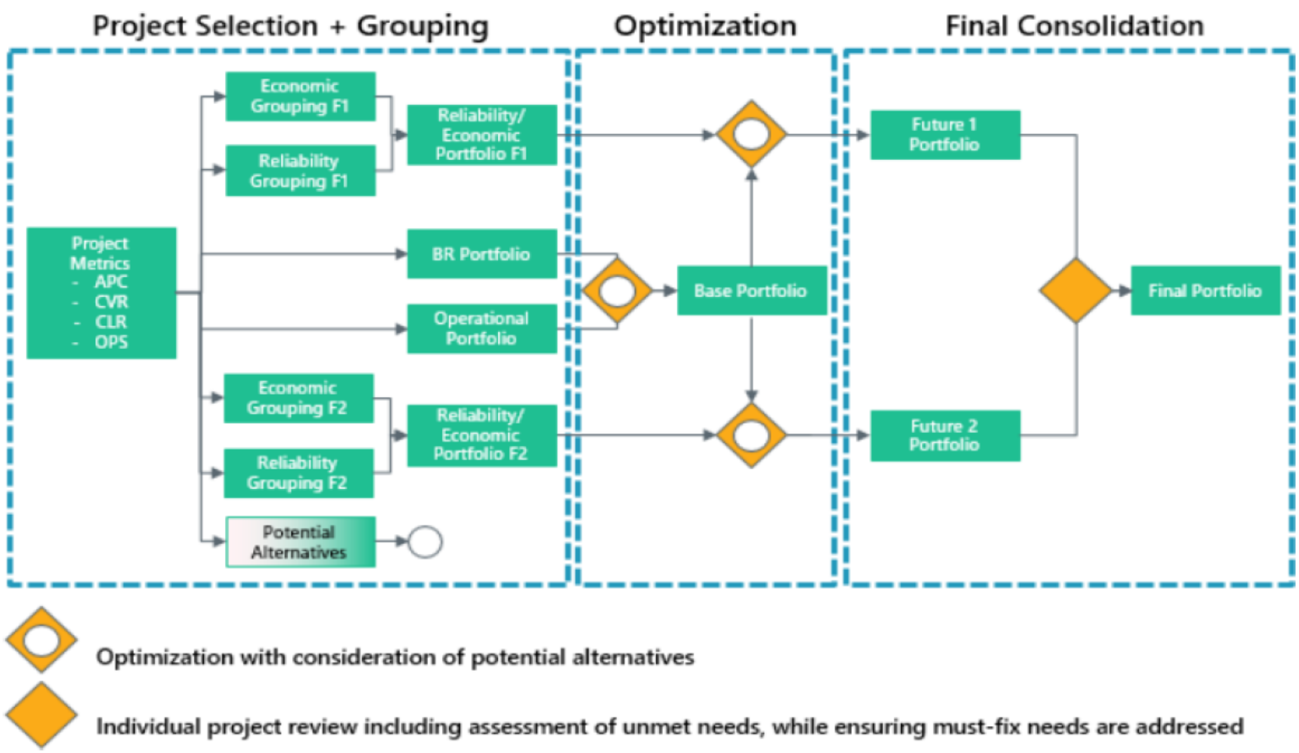
If renewables come online faster than the ISOs are currently planning for, then the market will suffer inefficiencies if transmission builds lag. Likewise, planning ahead for renewable buildout can help to enable greater buildout and lower system costs. Therefore, a comparison of our methodology and inputs compared to the ISOs is useful as context. The following discusses each ISO's transmission planning process for economic projects.

SPP

SPP's Integrated Transmission Planning (ITP) uses a project-portfolio approach and several optimization steps that blends economic and reliability needs. The 2019 ITP considered two sets of future assumptions, a Reference Case and an Emerging Technologies case. The process is shown below:

[9] MISO's latest MTEP only reports total buildout by 2033, which is higher than our buildout by 2024, so we are unsure about the comparison in builds by 2024. However, our buildout is clearly higher than ERCOT or SPP assumptions. See Appendix for more details.

Exhibit 2-2: SPP's Integrated Transmission Planning (ITP) Process



Source: SPP

SPP's assumed buildout in the 2019 ITP is as follows for each scenario. ICF's assumptions are much more in line with SPP's Future 2, as shown below. SPP does not report thermal build MW specifically.

Exhibit 2-3: New Builds Comparison – ICF and ITP 2019

Incremental Builds Assumptions Through 2024 (GW)			
Type	**ICF Assumptions**	**SPP ITP 2019 Future 1**	**SPP ITP 2019 Future 2**
Solar	9.6	5.0	7.4
Wind	3.9	2.7	4.0

Within this mixed process, economic transmission projects are first screened individually and must show benefit/cost ratios of at least 0.5 for individual study years (2021, 2024, and 2029) or a 40-year NPV of 1.0. Adjusted production costs are used as the benefit metric. Projects passing this initial screen are then grouped into three portfolios for each future scenario: a least-cost per APC dollar saved, a highest net APC dollar benefit, and a multi-variable portfolio that also includes considerations like environmental and permitting, public policy needs, and whether new infrastructure is needed. One of these three groupings is then selected for each future scenario to move forward.

The economic projects then move through several steps to co-optimize the portfolio with reliability needs and harmonize the results of future scenarios 1 and 2. In 2019, the ITP highlighted two Study Areas of overlapping reliability and economic needs for additional region-specific analysis and optimization. In the final analysis, the 2019 ITP used a scoring rubric for approval of specific projects to move forward on an economic basis as shown below:

Exhibit 2-4: 2019 ITP's Scoring Rubric

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

Source: SPP

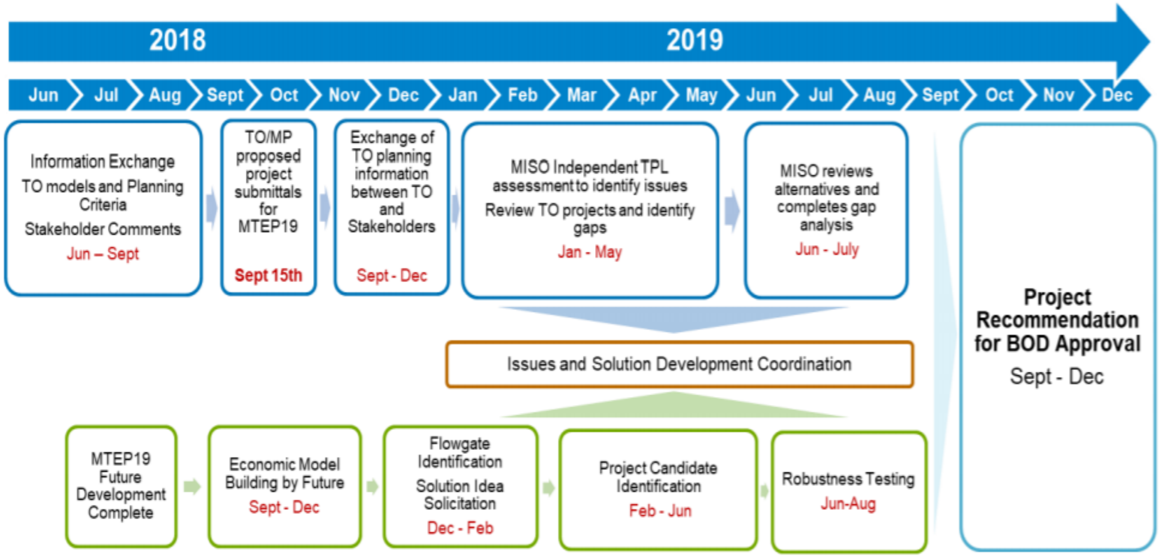
Project had to score at least a 70 out of 100 to obtain final approval; SPP also applied discretion in approving one project just below the threshold.

SPP uses PROMOD for the SCED analysis (consistent with ICF), but has not reported the tools used for powerflow analysis.

MISO

MISO's economic transmission planning proceeds parallel to the reliability analysis, as shown below:

Exhibit 2-5: MISO's MTEP Process



Source: MISO

For the economic analysis, MISO developed four future scenarios: limited fleet change, continued fleet change, accelerated fleet change, and a distributing and emerging technologies case. Years 2023, 2028, and 2033 are modeled. Unfortunately, MISO only reports total builds over the entire horizon 2019-2033, so we do not have a comparison of builds in the near-term that could be compared with ICF's assumptions. However, it is safe to assume that MISO's Limited Change and Continued Change cases contain lower buildout than ICF's assumptions.

Exhibit 2-6: New Builds Comparison – ICF and MTEP 2019

Incremental Builds Assumptions (GW)					
Type	ICF Assumptions through 2024	MISO METP19 Limited Change Case: 2033	MISO METP19 Continued Change: 2033	MISO METP19 Accelerated Change: 2033	MISO METP19 DER and Emerging: 2033
Solar	8.7	7.2	13.5	30.4	42.7
Wind	12.3	3.6	10.8	42.0	10.8
Gas	2.3	19.2	28.8	22.8	21.6

In a two-step screening process, MISO requires that projects show a benefit/cost ratio of at least 1.0 compared to the average result in each of the four future scenarios. In each case, MISO includes both near-term generation from the interconnection queue and further economic builds over time.

Projects passing this screening step are then further tested for robustness against alternative generation and transmission inputs in each of the four future scenarios. For example, in 2019, the scenarios tested included higher/lower wind builds (sensitivities on their own) and/or with new transmission upgrades assigned to projects in the interconnection queue. Projects must show general robustness against these scenarios (no specific parameter was defined).

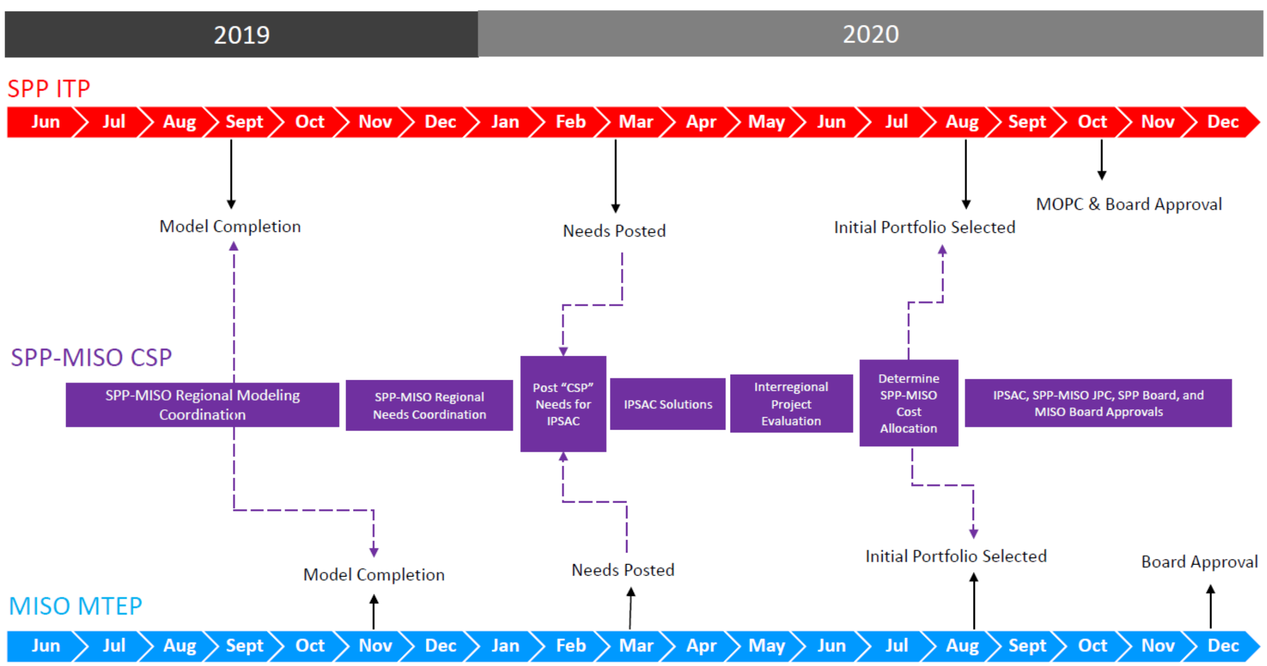
Finally, MISO considers economic projects addressing joint needs with SPP, PJM, and across the MISO North-South seam. In the final analysis, MISO requires projects to meet a 1.25 benefit/cost ratio.

Like SPP, MISO uses PROMOD for the SCED analysis (consistent with ICF), but has not reported the tools used for powerflow analysis.

Cross-Market Coordination in Eastern Interconnect

Neighboring ISOs have set up Interregional Planning Stakeholder Advisory Committees (IPSACs) to separately study economic projects that directly affect seams or flow issues between markets. Between MISO and SPP, coordination has advanced to where cross-market issues are considered within each ISO's normal transmission planning process through a Coordinated System Plan (CSP). The process is illustrated as follows:

Exhibit 2-7: MISO-SPP Coordinated System Plan Timeline and Process



Source: SPP-MISO Annual Issues Review

After setting up the initial modeling, each ISO submits possible projects to the other that have potential for mutual benefits. These are then considered as part of each ISO's normal evaluation process. Historically, if a project passes each market's benefit/cost criteria *and* at least 5% of the benefits flow to each market, the project is approved.

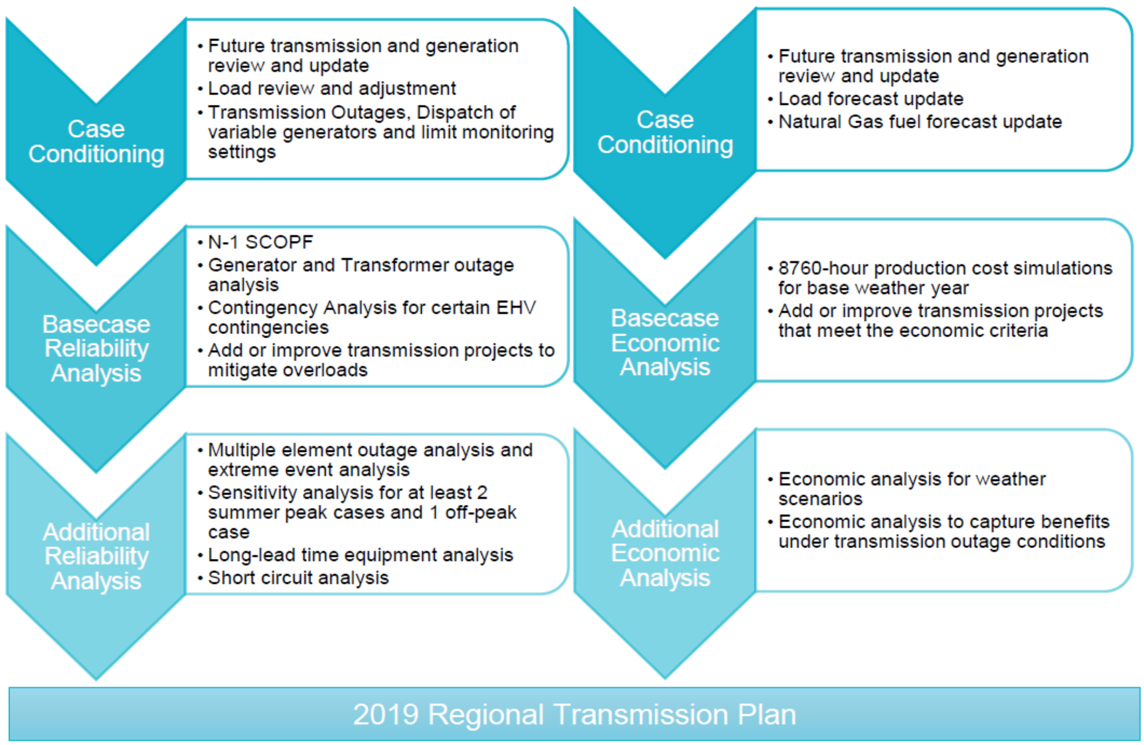
MISO and PJM also have a working IPSAC and a Coordinated System Plan structure in place, but most studies have taken place outside of the normal transmission planning processes. PJM and MISO ran a separate, two-year Interregional Market Efficiency Projects study over 2018/2019, rather than using a CSP. One-off processes can also occur; for example in 2018, the markets ran a Targeted Market

Efficiency Plan (TMEP) study to specifically look at seams issues outside of the typical transmission planning process, focusing on existing issues with low-cost solutions.

ERCOT

As with MISO, in ERCOT, reliability analysis and economic analysis are done on parallel tracks, starting from essentially the same transmission and generation assumptions. Therefore, reliability projects authorized in the current RTP are not assumed as online in the economic evaluation.

Exhibit 2-8: ERCOT Regional Transmission Plan Process



Source: ERCOT

ERCOT only includes new generators that have posted letters of credit for interconnection. This leads to a very limited set of new builds, almost all of which are assumed to come online within ~12 months of the study date. No further builds are assumed between 2021-2024. ICF's assumptions for renewable buildout are therefore much higher than ERCOT's 2019 RTP, as shown below:

Exhibit 2-9: MISO-SPP Coordinated System Plan Timeline and Process

Incremental Builds Assumptions Through 2024 (GW)		
Type	ICF Assumptions	ERCOT 2019 RTP Assumptions
Solar	8.3	3.1
Wind	11.8	9.6
Gas	6.1	0.7

Note: ICF calculated ERCOT totals from June 2019 GIS based on ERCOT's Planning Guide 6.9(1) criteria. ERCOT does not report explicitly the total capacity included in its RTP

ERCOT uses production cost savings as the metric for social benefits. For economic projects, ERCOT studies years two and five beyond the current RTP; for example, the 2019 plan (finalized in December 2019) studies years 2021 and 2024 for economics. If the production cost savings equal or exceed the first-year annualized revenue requirement for the transmission project[10], the project is recommended (e.g. levelized benefit/cost ratio of 1). Protocols stipulate, however, that a "qualitative assessment is made of whether the factors driving the production cost savings due to the project can reasonably be expected to continue" before projects can receive approval. ERCOT has used this as a reason to deny economic projects in the past.

ERCOT may also choose to do sensitivity testing of the economic projects by using renewable output profiles from different years and/or transmission outage sensitivity cases. In some cases, ERCOT has also found projects to be economic, but held off on approval until alternative solutions have also been tested (the STP-Elm Creek project is one example). Finally, ERCOT has occasionally blended reliability and economic needs in evaluating large new projects. For example, large 345kV reliability projects are checked against the Long-Term System Assessment needs, which considers economics, and large economic projects are checked for reliability impact (for example, the Kendall-Bergheim area upgrades were not approved on economics alone, but ERCOT noted that an additional transmission path in this area could be beneficial for reliability, and therefore justifies further study).

ERCOT uses the UPLAN model for SCED analysis, and PSSE/PowerWorld for additional powerflow modeling.

A comparison of input assumptions in each ISO's most recent planning process, to the extent available, is shown in Appendices 1-3.

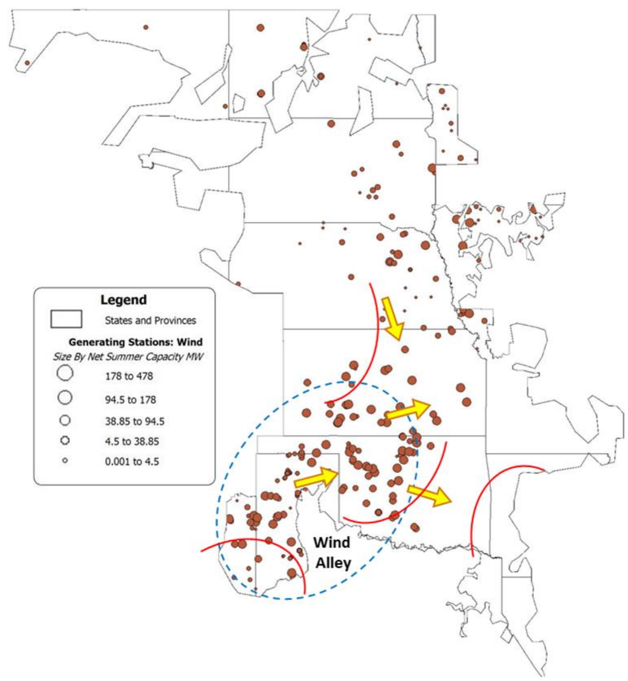
[10] ERCOT considers the financial parameters used in this assessment as confidential. However, recent publicly-released data from the Regional Planning Group indicates roughly 0.14 as a benchmark.

3. Discussion: SPP

At around 50 GW peak demand and with 20 GW of installed wind as of fall 2019, SPP has the highest penetration of wind amongst major markets. Wind was already the second-largest source of energy in 2018, however, growth of wind has slowed somewhat due to increasing challenges in the interconnection process.

The highest quality wind resources are in the southwestern parts of the market (the so-called "wind alley" comprising the TX panhandle, western OK, and southwestern KS), whereas load centers are generally located in the eastern parts of the market. There are two major trading hubs (North and South), of which South is the most liquid. South Hub buses cover central Oklahoma, including around Oklahoma City load area.

Exhibit 3-1 Location of Wind Projects and Typical Congestion Interfaces in SPP



Map source: ABB Velocity Suite

Power flows from the "wind alley" to the east and from northern SPP to the south. Historically, congestion has been most negative in the northern and eastern areas of SPP. Basis interfaces have tended to form in the center of KS and OK, as flows into Oklahoma City and Kansas City often create congestion for wind generators located further west. Northwestern SPP tends to experience the lowest prices, due to both congestion and long-distance loss components, while southeast SPP has the highest prices being on the opposite side of constraints.

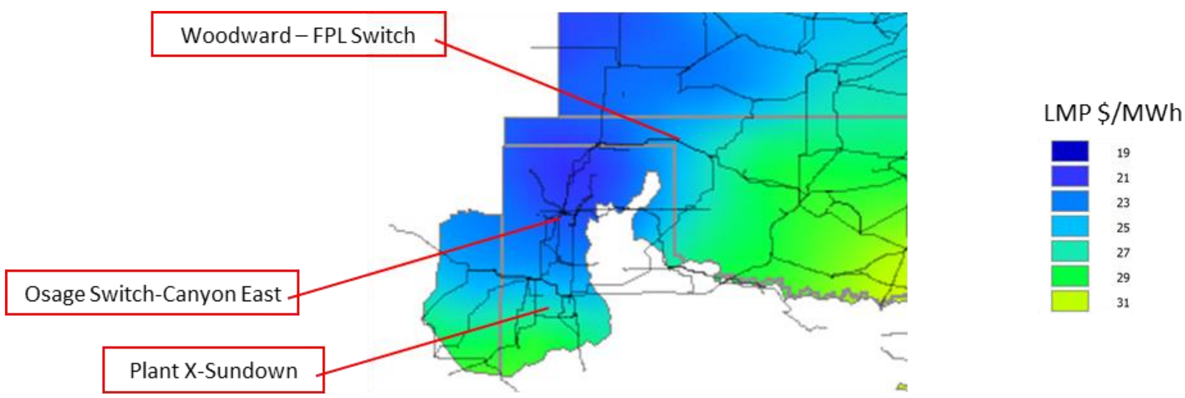
3.1 Historical Congestion 2015-2019

Congestion in SPP has improved meaningfully from 2015 to present. The following general trends have been observed:

Decongesting the TX/OK panhandles and southwest KS:

In 2015 through 2017, some of the lowest prices in the market were seen in the Panhandle regions due to challenges in moving wind power to load centers elsewhere in the market. Congestion interfaces formed not only moving power to the major SPP load centers in the east, but also to smaller load centers in SPS New Mexico and exports to WECC PNM territory. The heat map shown below representing 2017 (on-peak shown to highlight congestion detail; off-peak patterns are similar) is illustrative of this trend:

Exhibit 3-2 Southwestern SPP Congestion (2017)



Map source: ABB Velocity Suite

Three major binding elements common over 2015-2017 which define the congested interfaces in the Panhandles are Plant X-Sundown, Osage Switch-Canyon East, and Woodward-FPL Switch.

Congestion grew sharply moving power to the southwest over these three years: in 2015, though minor congested elements existed, none were among the top ten most binding elements in the market. In 2016, Plant X-Sundown was binding in 10% of hours, and a nearby constraint Wolfforth-Terry County (contingency at Sundown) was binding in 19% of hours. In 2017, congestion grew further and Plant X-Sundown was binding in 19% of hours, with other nearby constraints also binding. Finally, in 2018, terminal upgrades at Plant X and Sundown to enable a line limit increase generally relieved the constraints, and in 2018 and 2019 southwest SPS was close to parity with the Panhandles.

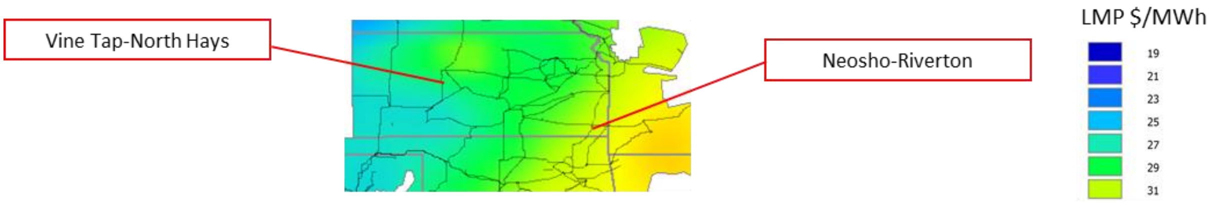
In the north TX Panhandle, Osage Switch-Canyon East was the second-most binding constraint at 27% of hours in 2015. Congestion eased in 2016 and 2017, though Osage Switch-Canyon East was still a top-ten constraint at 5% and 4% of hours, respectively. By 2018, with upgrades in the surrounding areas, no constraints in the TX or OK panhandles were significant; this has continued in 2019.

Finally, Woodward-FPL Switch was the market's most important constraint over 2015-2017 at 27%, 35%, and 23% of hours binding, respectively. The major 345kV project Woodward-Tatonga-Mathewson, completed in 2018 (the most expensive project SPP has undertaken over the past five years at $180MM budgeted) finally relieved the congestion, allowing wind in the Panhandles and the entire western part of SPP to deliver greater power to Oklahoma City and the rest of SPP South Hub.

Patchwork upgrades in Kansas

Two areas in Kansas have consistently shown up as congestion centers over the past five years: the Hays region in central KS and the Neosho-Riverton constraint in southeast KS. The 2018 on-peak average price is illustrative of general congestion/flow patterns in the region:

Exhibit 3-3 Congestion in Kansas (2018)



Map source: ABB Velocity Suite

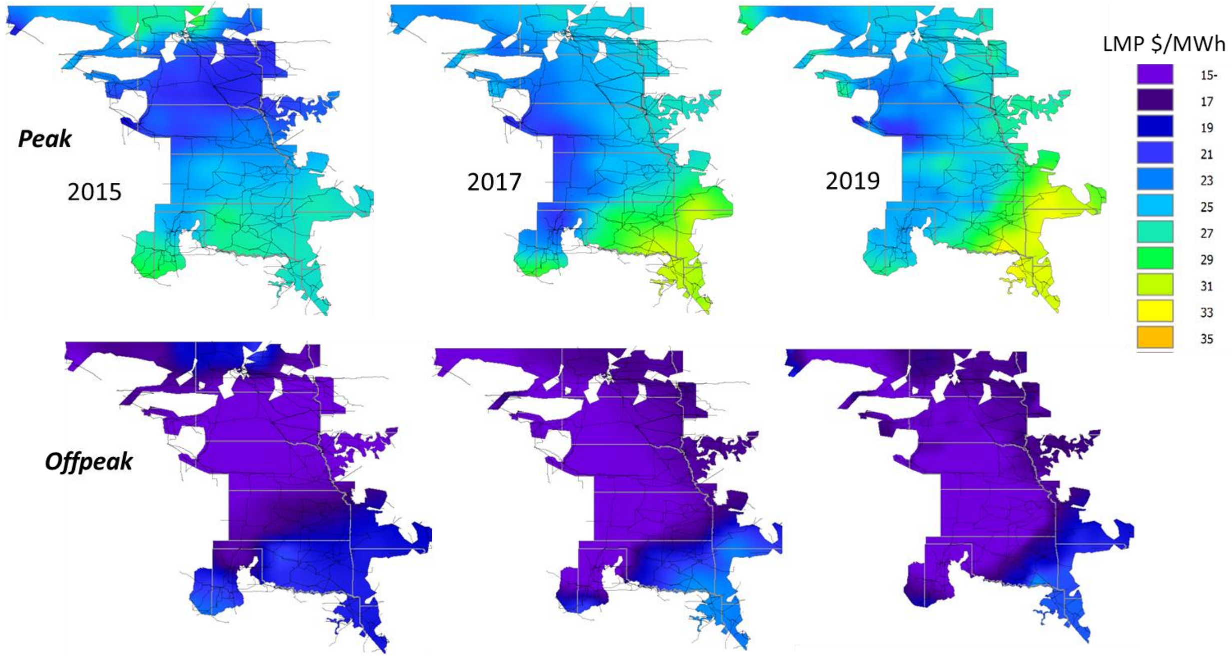
Constraints around the North Hays and Knoll substations have been in the top-ten list every year since 2015 at 5-10% of hours binding, creating positive congestion locally (import constraint rather than export) but lowering prices for nearby wind generators. 230kV upgrades at Knoll-Post Rock were completed in 2018, but have not fully relieved the congestion.

After Woodward-FPL switch, Neosho-Riverton in southwest KS has been the second-most important constraint in the market over the past several years. Congestion grew over 2015-2016, and by 2017 was binding in 18% of hours, in part due to transmission outages on neighboring Delaware-Northeast 345kV during the fall. Being near the MISO border, the constraint has also been a focal point of MISO-SPP transmission coordination. Over 2017-2019, the MISO-SPP Interregional Planning Stakeholder Advisory Committee (IPSAC) studied the project three separate times, but have consistently failed to conclude on a recommended upgrade. Congestion on Neosho-Riverton continues to fluctuate.

General improvements in congestion to South Hub

Overall, primarily with the Woodward-Tatonga-Mathewson upgrade in 2018, congestion for wind has improved across the broader market. In 2018, no constraint was binding for more than 10% of hours, while in the previous years, the top two constraints were consistently binding for 20-30% of hours. In 2015, market wide congestion was overall a north/south issue. By 2017, after an additional 5 GW of wind and various upgrades, congestion was mostly an east/west issue. Finally, in 2019, after the major 345kV upgrades and slowing growth of wind, congestion is mostly between rest-of-market and the southeast.

Exhibit 3-4 Evolution of LMP in SPP



Map source: ABB Velocity Suite

3.2 Projected Congestion 2024

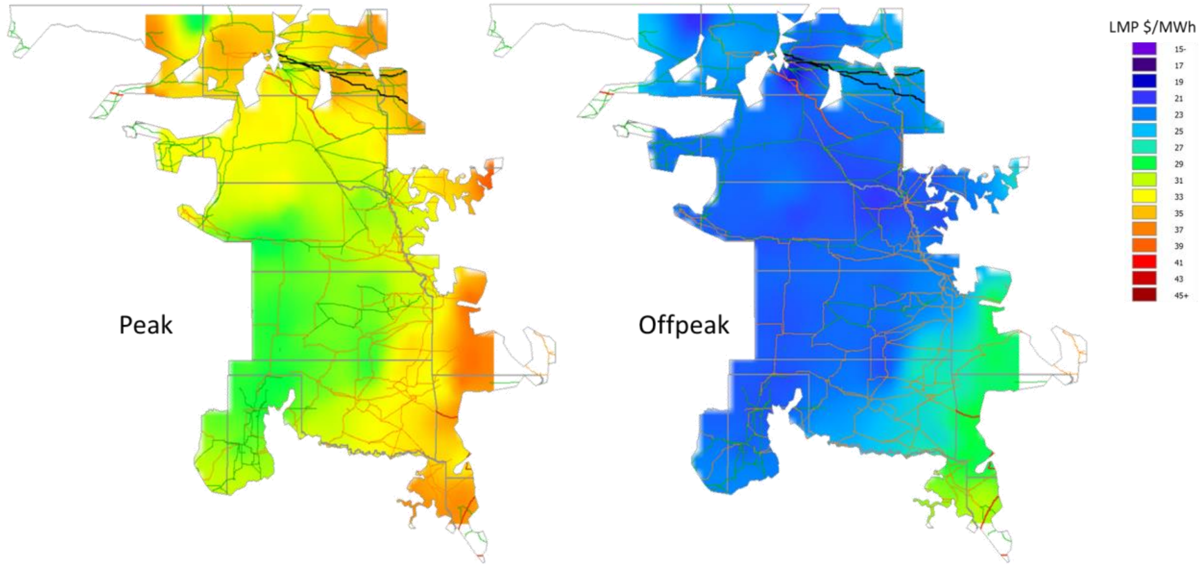
ICF implemented the following parameters in our modeling in 2024 according to our own internal assumptions with additional wind capacity projected by AWEA (showing 2019 for comparison). ICF implemented all currently approved transmission projects, with projects under Delay-Mitigation status given a one-year delay.

Exhibit 3-5 ICF Modeling Parameters in 2024 for SPP

Parameter	2019	2024
Installed Wind MW	19,676	29,373
Installed Solar MW	341	4,241
Peak Demand MW	50,662 (2019 actual)	53,957
Total Energy TWh	262.4 (SPP est.)	271.6

The projected on-peak and off-peak congestion patterns for SPP in 2024 are shown in Exhibit below. We project similar congestion patterns as those seen in 2019, with the major congestion interface being rest-of-market vs southeast, especially in off-peak.

Exhibit 3-6 Base Case LMP Projection for SPP in 2024



Map source: ABB Velocity Suite; compiled by ICF using historical and projected prices

Despite the migration of Lubbock Power and Light (~450 MW peak) to ERCOT and a large increase in local wind capacity, we do not project significant congestion moving power from the TX/OK Panhandles to New Mexico as seen historically. With the implementation of equipment upgrades at Plant X and Sundown stations, new 345kV lines from Bopco-Road Runner and Bopco-China Draw, and a new 345kV line from Hobbs to Yoakum around the TX/NM border, only a mild basis premium exists in southeast SPS territory.

The increase in wind capacity in the "wind alley" does cause continuing congestion near Oklahoma City. Constraints center around Cimarron substation, which is the terminus of the circuit that runs through Woodward, Tatonga, and Mathewson substations upstream as the major carrier of wind power from the wind alley to load. The Cimarron transformer is binding for 13% of hours in 2024, causing $34MM in congestion cost to the market. This is higher than recent historical (Cimarron was binding in 4% of hours through spring 2019) due to increased wind, but congestion is not nearly as significant as seen during 2015-2017. Further, the total increase in wind flowing into central OK (including local builds) pushes down prices at South Hub.

Further northwest, the Tulsa OK area becomes the nexus of the market's second-most binding constraints in 2024. In 2018 and 2019, the Cleveland-Cleveland AECI constraint entered the top ten list, but with less than 5% of hours binding in each case. By 2024, Cleveland-Afton Tertiary becomes binding in 18% of intervals, and neighboring Fairfax tap-Shidler Circuit becomes binding in 25% of hours. Total congestion costs for constraints around Tulsa total $112MM in 2024. This area of the grid is slated for a major new 345kV line direct from Wekiwa to Sooner substations in 2026; Cleveland substation is on the 345kV line currently connecting these two substations and would be bypassed.

In Kansas, the Hays area is no longer congested, but constraints in the southeast portion of the state are still critical. While Neosho-Riverton is less binding than historically at around 7% of hours in 2024, neighboring lines Butler-Altoona and Waverly-La Cygne become increasingly congested; total costs for constraints in the area total $53MM. These low voltage lines are increasingly subjected to loading under

N-1 loss of the 345kV lines, of which there are few redundant paths in this part of the grid. This area is the site of the approved Wolf Creek-Blackberry 345kV new line in 2026, which bypasses Neosho and La Cygne substations.

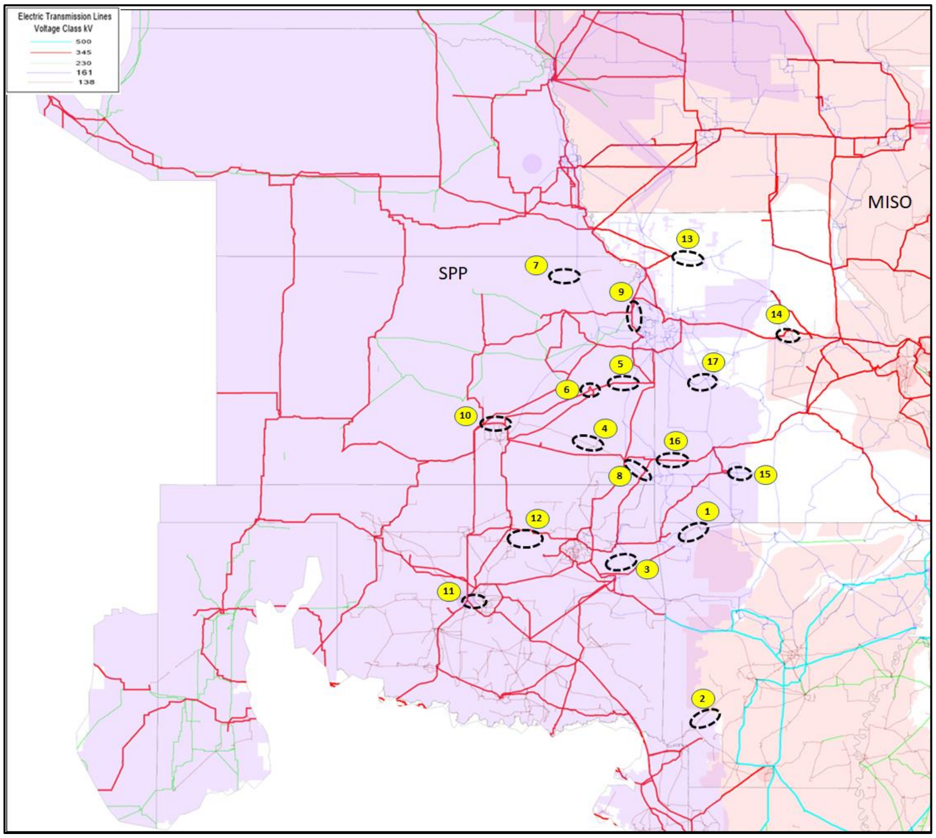
Finally, congestion is observed in Missouri near the seams with MISO, centering around Fairport-Hickory Creek (the most binding constraint in our modeling in 2024) and Overton transformer. Demand pull in MISO Missouri grows over time but less new wind is constructed there than in other areas of MISO. On the other side of the constraint, new wind is added in SPP Nebraska and Kansas far in excess of local demand growth. This growing mismatch in supply squeezes the already narrow corridors between the two ISOs.

Top constraints in 2024 with binding hours and congestion costs are shown in Exhibit 3-7.

Exhibit 3-7 SPP Top Projected Constraints in 2024

Region	Index	Constrained Element	2024 - Base Case	
			Binding Hours (#)	Congestion Cost ($ MM)
AEPW	1	Avoca to East Rogers Circuit - 1	1,818	31.4
		Beaver to Eureka Springs Circuit - 1	1,454	27.6
	2	Patmos West AECC to Fulton Circuit - 1	3,026	29.0
	3	Kerr to Maid Circuit - 1	496	14.9
		Tahlequah to Highway 161 kV Circuit -1	966	14.9
Kansas	4	Butler to Altoona Circuit - 1	1,728	17.7
	5	Waverly to Lacygne Circuit - 1	284	13.5
	6	Wolf Creek Transformer Circuit - 1	1,042	11.5
	7	Marshall to Smittyville 115 kV	1,500	3.9
	8	Neosho to Riverton Circuit - 1	580	6.4
	9	Stranger Creek to Iatan 345 KV Circuit - 1	48	0.6
	10	Wichita - Benton 345 kV	62	0.8
OKGE	11	a. Cimarron Transformers - 1	1,148	34.1
		b. CZECH Hall to Cimarron Circuit - 1	778	21.2
		c. Haymaker to Cimarron Circuit - 1	206	5.2
		d. Cimarron to Draper Lake 345 Circuit - 1	148	2.6
	12	a. Cleveland to Afton Tertiary Circuit - Z1	1,546	50.9
		b. Fairfax Tap to Shidler Circuit - 1	2,164	38.6
		c. Webb City Tap to Osage Circuit - 1	1,286	22.7
SPP Missouri	13	Fairport to Hickory Creek Circuit - 1	4,776	74.0
	14	Overton Transformer - 1	1,018	34.1
	15	Springfield to Clay Circuit - 51	2,306	29.8
	16	Blackberry to Jasper Circuit - 1	676	23.1
	17	Clinton to Truman Circuit - 1	366	8.9

Exhibit 3-8 Location of SPP Top Projected Constraints in 2024



Map source: ABB Velocity Suite

3.3 Studied Transmission Upgrades

ICF studied upgrades in three areas of SPP: southeast Kansas around the Wolf-Blackberry planned new line, the MISO seam around Overton transformer in Missouri, and the Oklahoma City area.

As mentioned, Wolf Creek-Blackberry was approved for economic upgrade by the Board in the 2019 ITP process, estimated in service by 2026 and not included in the preceding 2024 Base Case. However, we started by testing the impact of the line in our 2024 case.

Our modeling inputs and process for evaluation of transmission lines differs from SPP's[11]. Contrary to expectations, our modeling indicates a benefit/cost ratio for the market less than 1 (only looking at 2024). The adjusted production cost savings are projected at $12MM in 2024, while the project cost is estimated

[11] For example, SPP awards bonus points for building new 345kV lines, runs multiple future buildout cases, considers reliability needs in addition to economic upgrades simultaneously, and consolidates multiple upgrades into a portfolio solution when evaluating effectiveness. The 2019 ITP was released after the start of ICF's evaluation, and therefore we have not included in the model the other reliability and economic projects identified therein. However, for economic projects, the single largest factor in SPP's evaluation is benefit/cost as measured by APC. This is consistent with ICF's approach in the present study. We have also prioritized use of a standardized approach for all three markets for consistency.

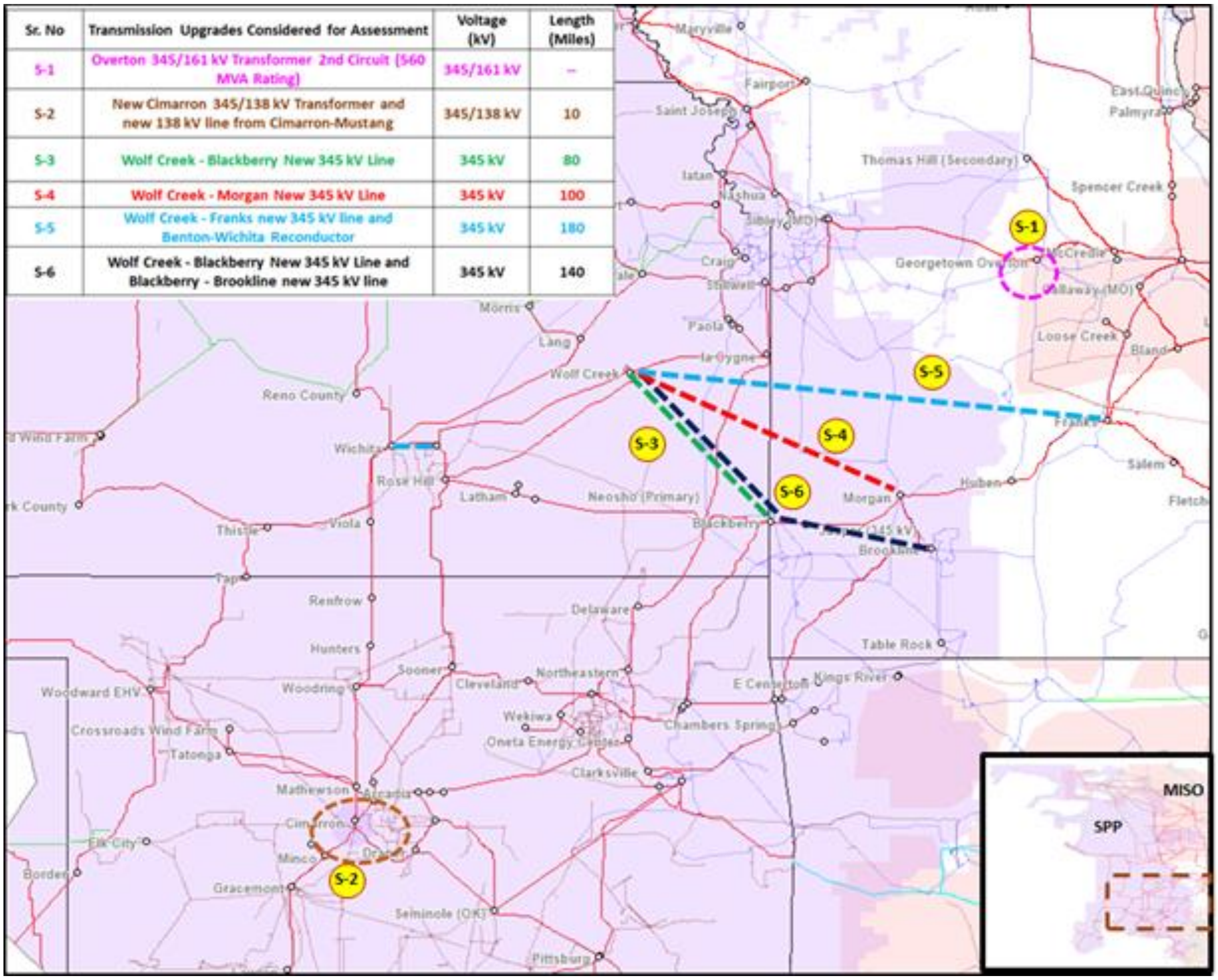
at $162MM using our generic cost methodology (which aligns very closely with SPP's actual estimate of $156MM).

We find that the line relieves the constraints at Neosho-Riverton, Waverly-La Cygne, and Butler-Altoona, but significantly raises the constraint cost at the next section, Blackberry-Jasper. The Blackberry-Jasper is a relatively old 345 kV line with rating less than 1000 MVA and is already moderately constrained in the Base Case. The new Wolf Creek-Blackberry line increases power flows into Blackberry substation (west to east flow) therefore exacerbating congestion on the Blackberry-Jasper. This constraint goes from binding in 8% of hours in the Base Case and $23MM congestion cost to 31% of hours and $157MM cost after the Wolf Creek-Blackberry build[12]. This reduces the overall effectiveness of the Wolf Creek-Blackberry project to the market.

Based on these findings, ICF tested building out further from Blackberry to Brookline substation in Missouri (number 6 in Exhibit 3-9 above) to give another outlet for power that does not pass through Jasper. Adding this second component to the line increased both APC savings considerably. Compared to only a $12MM APC savings for the first segment (Wolf Creek-Blackberry), adding Blackberry-Brookline increased APC savings to $101MM. The benefit/cost ratio for the whole project goes from 0.8 to 3.6; considering only Blackberry-Brookline independently after assuming the first segment, the benefit/cost would be 7.4. While this second upgrade still inflames some further constraints (such as Springfield-Clay Circuit), it relieves Blackberry-Jasper entirely.

[12] In the course of modeling, we found that increase in congestion on the Blackberry-Jasper is also sensitive to supply assumptions in Missouri, on the other side of Jasper substation. In both ICF and SPP's models, the James River coal plant near Springfield, MO is retired. If this generation is replaced by new wind plants, as in the SPP's study, congestion on Blackberry-Jasper line is expected to be lower. ICF's modeling does not include new wind in this area because there are no wind plants in the interconnection queue with signed IA.

Exhibit 3-9 Upgrades Studied in SPP



Sr. No	Transmission Upgrades Considered for Assessment	Voltage (kV)	Length (Miles)
S-1	Overton 345/161 kV Transformer 2nd Circuit (560 MVA Rating)	345/161 kV	–
S-2	New Cimarron 345/138 kV Transformer and new 138 kV line from Cimarron-Mustang	345/138 kV	10
S-3	Wolf Creek - Blackberry New 345 kV Line	345 kV	80
S-4	Wolf Creek - Morgan New 345 kV Line	345 kV	100
S-5	Wolf Creek - Franks new 345 kV line and Benton-Wichita Reconductor	345 kV	180
S-6	Wolf Creek - Blackberry New 345 kV Line and Blackberry - Brookline new 345 kV line	345 kV	140

Map source: ABB Velocity Suite. ***Please note:*** *projects labeled S-4 and S-5 were exploratory and not included in the final study. S-3 shows the path of the approved Wolf Creek-Blackberry line.*

The existing Blackberry-Jasper-Morgan-Franks 345kV line runs parallel to the Sibley-Overton 345kV line further north, each connecting SPP and MISO. While we did not separately test large new 345kV lines on the northern route, we did test smaller-scale upgrades at Overton transformer (adding a second 345/161kV circuit with 560 MVA rating) to increase the transfer capability. We expected increased transfers to benefit wind in SPP and reduce load prices in Missouri on the MISO side. However, this was found to be a poor solution on many fronts, causing increased APC both in SPP and MISO (therefore yielding a negative benefit/cost).

When Overton is upgraded, local constraints disappear, but every other path from SPP to MISO becomes more congested. This indicates a more general transfer issue between SPP and MISO that requires larger-scale upgrades than simple transformer equipment upgrades at Overton. For example, when we tested adding the Blackberry-Brookline segment to the Wolf Creek-Blackberry line, issues at Overton disappeared.

Finally, moving to another part of the market, as mentioned previously we find that Cimarron substation outside of Oklahoma City becomes a notable constraint in 2024. We tested an upgrade that involved building a short 138kV line from Mustang to Cimarron and adding a 138/345kV transformer to the existing 345kV Cimarron substation. This was found to be a highly effective solution: for just $22M in total upgrade cost, APC in SPP dropped by $54MM.

Final results for each line are shown in Exhibit 3-10. By implementing Blackberry-Brookline and Cimarron-Mustang, adjusted production costs in SPP drop by $142MM and cost to serve load drops by $25MM in 2024, saving consumers money and increasing overall efficiency. We have also shown the APC summary for MISO to illustrate the effect on flows between the markets. Among the recommended upgrades, MISO consumers also stand to benefit.

Exhibit 3-10 Summary of SPP Upgrade Results- Single Year Assessment (2024)

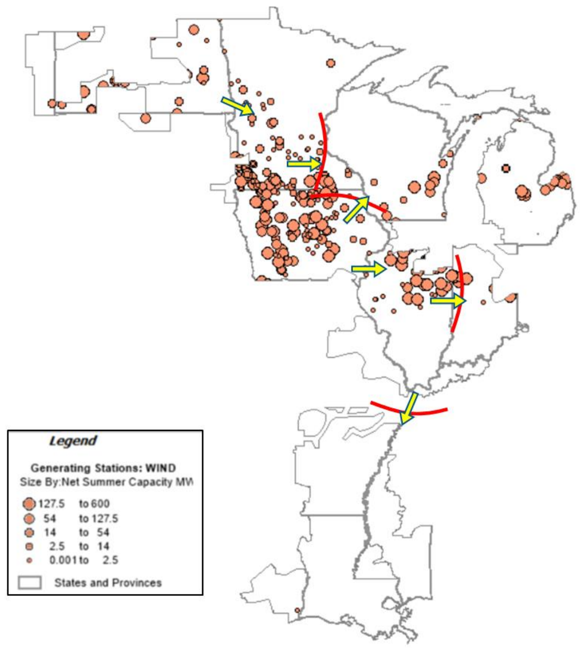
Upgrade ID	Upgrade	$MM Adj. Production Cost Savings	APC Benefit/cost Ratio for SPP	APC Benefit/cost Ratio for MISO	Est. Project Cost $MM
S-1	Overton 345/161 kV Transformer 2nd Circuit @560 MVA	-1	-1.2	-4.5	7
S-2	New Cimarron 345/138kV Transformer and new 138kV line Cimarron-Mustang	54	24.5	0.8	22
S-6	Blackberry-Brookline new 345kV assuming Wolf Creek-Blackberry	89	7.4	12.7	120

Note: Cimarron upgrade shaded green for benefit/cost in MISO despite being lower than 1 because MISO would not pay for the upgrade but would experience some modest economic benefits; there is not projected to be an affected system cost imposed.

4. Discussion: MISO

MISO has about 20 GW of wind as of December 2019, concentrated in the northwest of the market. Iowa, Minnesota, and the MISO portion of the Dakotas contain 75% of the installed wind base. Iowa, with 8.3 GW installed and a local peak demand of only around 8.5 GW, may have the highest relative wind penetration of any state in the country. Partially as a result, these areas experience the most congestion and lowest prices in the market.

Exhibit 4-1 Location of Wind Projects and Typical Congestion Interfaces in MISO



Map source: ABB Velocity Suite

These areas are also expected to see most of the new wind built over the next five years. However, growth is expected to pick up in eastern MISO – Illinois, Indiana, and Michigan will add 4.1 GW of wind by 2024 largely as a result of utility carbon reduction goals. MISO South has weaker potential for wind and is only projected to add 200 MW by 2024 in our study.

Power is traded at several hubs throughout MISO of varying liquidity. The most liquid hub overall is Indiana, though wind plants with hub-settled contracts may trade more frequently at hubs further west such as Minnesota Hub.

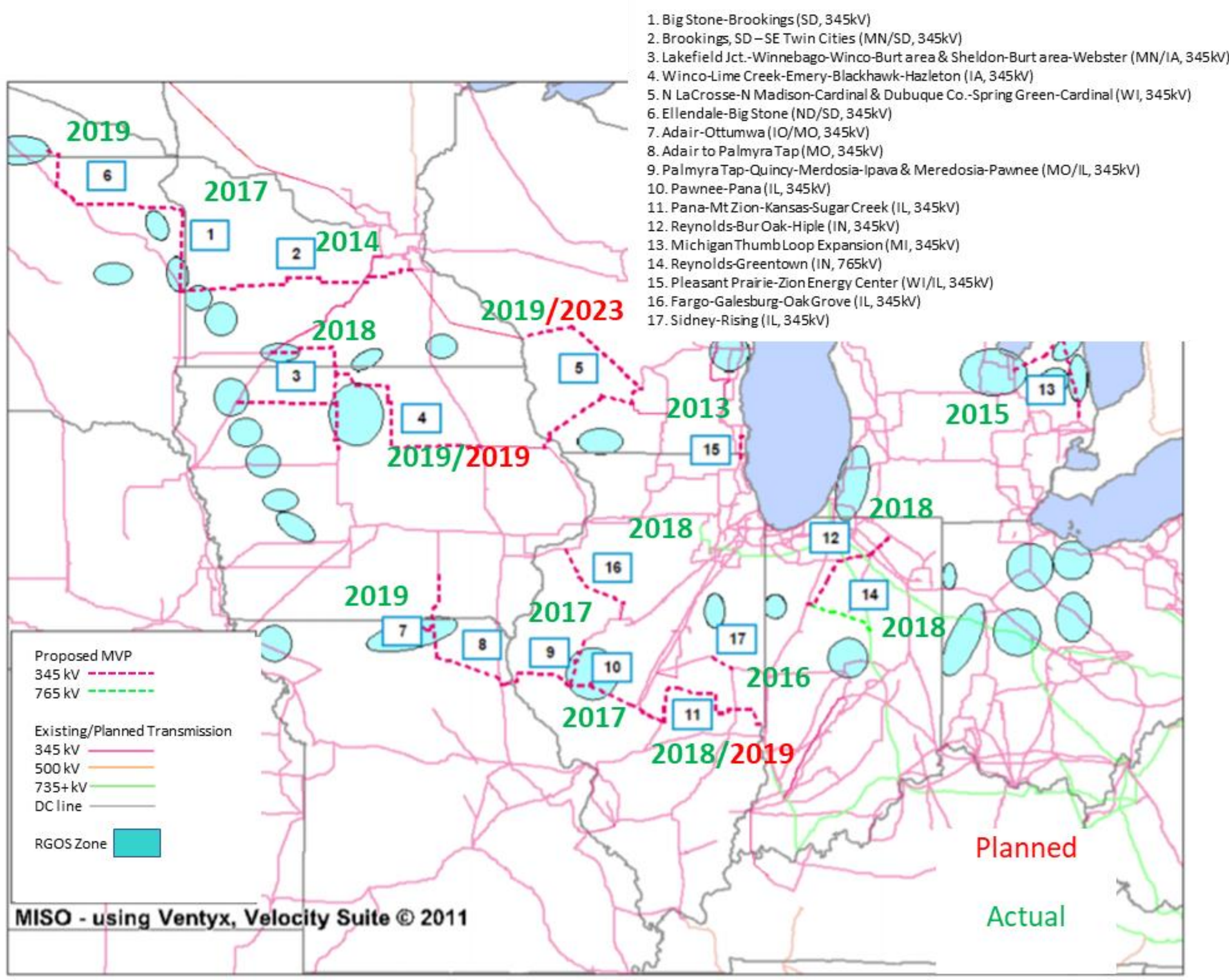
4.1 Historical Congestion 2015-2019

Congestion generally arises from west to east flows in MISO, and is influenced by:

- Supply/demand imbalances (excess capacity in the west; tighter supply conditions and greater demand in the east[13]),
- Wind generation concentrated in the west,
- Coal cost imbalances due to much further transportation requirements for PRB-fired plants in eastern MISO compared to western states,
- Long transmission distances leading to high loss components in LMP formation,
- Transmission constraints both within MISO and at the boundaries of the neighboring EI markets

Over 2015-2019, congestion across MISO has reduced, largely as a result of the MVP projects greatly increasing connectivity from west to east.

Exhibit 4-2 MISO MVP Project Summary



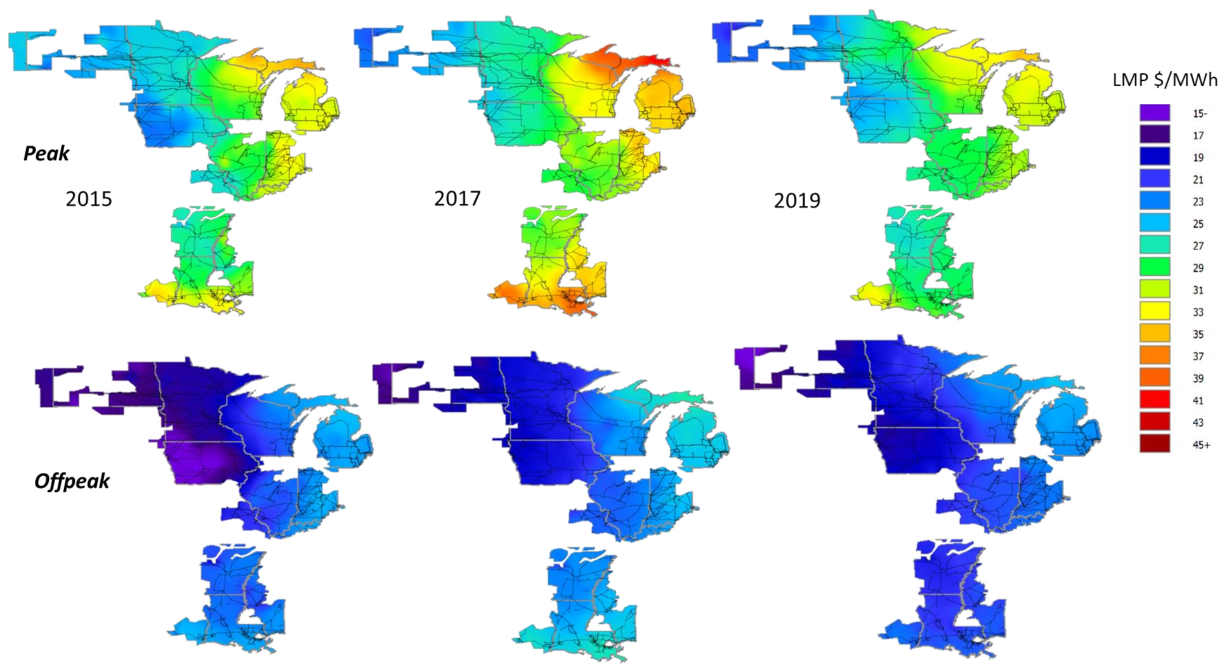
Map source: MISO. Text copied and overlaid by ICF for picture clarity. In-service dates added by ICF. As of Q4, 2019.

[13] For example, in the MISO capacity market, Zone 1 (MN) has consistently separated lower than the rest of the market and is a net exporter, whereas Zones 4 and 7 (IL and MI, respectively) are importers and have at times separated out higher than the rest of the market.

While portions of four MVP projects are still pending, the upgrade of the high-voltage network over the past five years has led to binding constraints migrating almost exclusively to the lower-voltage network. In 2018-2019, among the top 30 constraints across Iowa, Minnesota, Illinois, and Indiana, only one occurs on a 345kV or above line (Gibson-Petersburg in southwest Indiana, binding for 3% of hours in 2018).

Congestion for 2015, 2017, and 2019 off-peak is shown in Exhibit 4-3 (MISO-South and far western ND cut off for size):

Exhibit 4-3 Historical Evolution of LMP in MISO



Map source: ABB Velocity Suite; compiled by ICF using historical price data

As congestion has eased, price separation in 2018 and 2019 represents loss component as much as it does the congestion component of LMP. For wind producers in western MISO, loss component of pricing can be around negative $3-4/MWh. In 2019, the congestion component was also around negative $3-5/MWh, for a total discount of ~$7-8/MWh (as shown in the chart below in section 2).

Iowa-Minnesota

In 2015, significant congestion in Iowa resulted in much lower prices than the rest of the market: five of the top 10 constraints by most binding hours were in Iowa or southern Minnesota. Rochester-Wabaco 161kV in southeastern MN, is the most notable. In 2015, it was the sixth-most binding constraint at 1,448 hours in the year; by 2019 YTD, it has been the second-most binding constraint in all of MISO at 2,162 hours. In 2018, MISO recommended reconductoring this line based on economic benefits; current schedule is for completion in 2023 (and is included in the Base Case for 2024).

Compared to 2015, with the completion of many MVP projects, congestion patterns have improved around Iowa/Minnesota, and in 2019 only Rochester-Wabaco is still on the list of top 10 market constraints, binding for 25% of hours. Instead, top constraints are now largely concentrated on the seams with SPP and PJM.

Cross-ISO Seams

The top constraint by hours in 2018 and 2019 (20% and 34% of hours, respectively) was Roxana-Praxair 138kV, located in northwest Indiana near COMED territory. The second-most binding constraint, Goodland-Reynolds (binding in 26% and 20% of hours in 2018 and 2019), is in the same area. In 2017, the MISO-PJM IPSAC recommended for approval upgrades in both of these area as two of five projects for market efficiency in both ISOs. The MISO and PJM boards both approved the upgrades.

Another major historical constraint is around Marblehead transformer and the Palmyra substation near the Illinois border with northern Missouri. Marblehead transformer has been binding for at least 1000 hours/year for each of the past five years, though congestion has reduced since 2015 when it was the top constraint at 2,971 hours (34%). While this does not actually border PJM territory, the constraint was been identified as a MISO-PJM market efficiency issue in the 2019 IPSAC. Two possible upgrade configurations were studied, but ultimately did not meet benefit/cost criteria in either PJM or MISO. Two other seams projects, primarily benefitting PJM, were recommended for approval.

Finally, several other constraints in northern Indiana near COMED have periodically been congested over 2015-2019. The Guion transformer was a top congested element in 2015, 2016, and again in 2018 (8-15% of hours), but has not been taken up as a MISO-PJM issue.

On the SPP side, the MISO-SPP IPSAC has had notably less success than the MISO-PJM version, with none of the recommended projects getting both ISO board approvals over the past three planning cycles. Raun-Tekamah, in SPP Nebraska near the Iowa border, is the sixth-most binding constraint in MISO in 2019 at 1,357 hours. MISO submitted the constraint as the highest priority on the MISO side of the seam in the 2019 IPSAC cycle, and two possible upgrades for the constraint were shortlisted out of seven total. However, after further evaluation, none of the seven projects were recommended[14].

4.2 Projected Congestion 2024

ICF implemented the following parameters in our modeling in 2024 according to our own internal assumptions with additional wind capacity projected by AWEA (showing 2019 for comparison). ICF implemented all currently-approved transmission projects, including Cardinal-Hickory Creek by 2024.

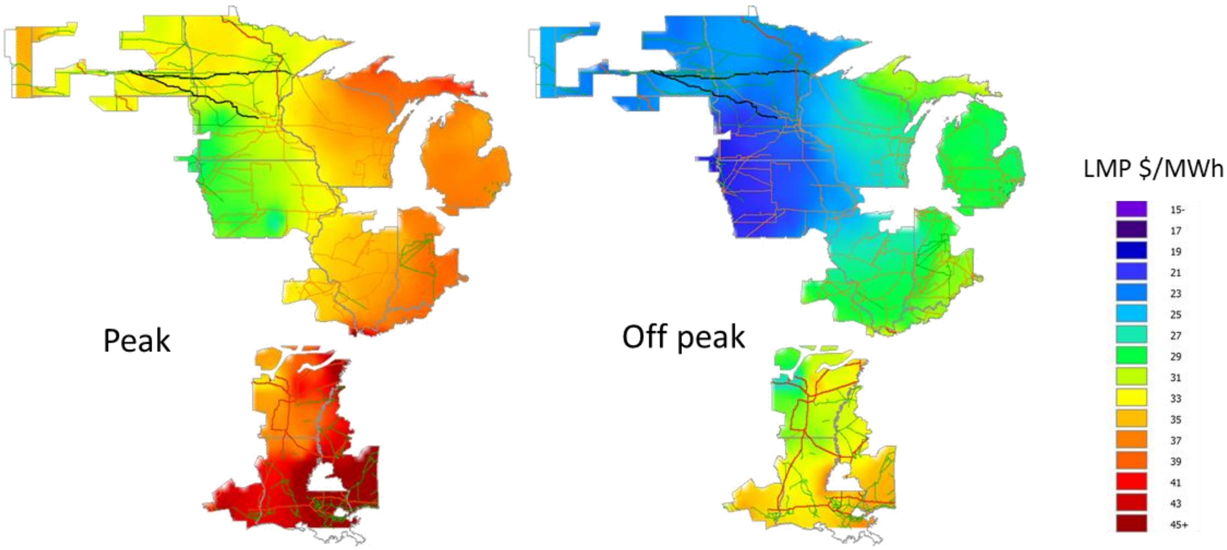
Exhibit 4-4 ICF Modeling Parameters in 2024 for MISO

Parameter	2019	2024
Installed Wind MW	19,619	31,933
Installed Solar MW	1,427	10,135
Peak Demand MW	124,878 (est.)	130,048
Total Energy TWh	688.7 (est.)	717.7

[14] Projects were not recommended because they failed to show 1.25x benefit/cost ratio in both markets, or did not meet the threshold of providing at least 5% of the total $ benefits to each market.

ICF projected the following on-peak and off-peak congestion patterns for MISO in 2024:

Exhibit 4-5 Base Case LMP Projections for MISO in 2024



Map source: ABB Velocity Suite

The projection for 2024 is generally for congestion patterns to remain similar to historical trends, but the magnitude of congestion is projected to become significantly worse. This is especially true for western MISO. As wind becomes a more dominant source of energy, its hourly output exerts more direct influence on the price across the west. The generation-weighted nodal basis for wind becomes more discounted than the average basis in 2024 than in the historical years: for example, in 2024, the time-weighted average nodal basis or a wind plant in Iowa is projected to be about $10-11/MWh with respect to Indiana hub, but the generation-weighted basis is projected to be $17-18/MWh.

Compared to historical levels, a growing portion of this basis in 2024 is due to loss component: -$3.3.MWh in 2019 vs -$7.0/MWh in 2024 (gen-weighted). Coal retirements in eastern MISO, and wind builds in western MISO, create a greater total movement of power from west to east and contribute to transmission losses. This effect is also more driving in the off-peak than the peak. Losses can be somewhat reduced, but not eliminated, by new high-voltage lines.

On the congestion side, even with the addition of 12 GW of wind, the high-voltage network, with the MVP additions, is less of a problem in moving power from west to east compared to the low-voltage network. Constraints are almost exclusively on sub-345kV lines, and are highly distributed throughout MISO. Overall, many of the constrained elements seen historically still show up in 2024.

In the west, the Rochester-Wabaco constraint goes away with the upgrade in 2023, but the next segment of line from Wabaco to Alma becomes constrained. There is little takeaway capacity at Wabaco substation, as it exists at the midpoint of a 161kV line without any other transmission-voltage connections. Wabaco-Alma is binding in 21% of hours and results in $51MM in congestion costs to the market in 2024.

Further west, Big Stone substation in South Dakota is a waypoint on a new 345kV line from the western part of the state into Minnesota as part of MVP. However, the sparse network creates overloads on low-voltage lines for contingencies involving the high voltage network. The most binding constraint is Big Stone to Browns Valley 230kV, binding in 9% of hours but creating $46MM in congestion cost.

In Indiana/Illinois, the MISO-PJM coordination projects take care of Roxana-Praxair entirely and reduce, but not eliminate, constraints around Goodland-Reynolds. Guion transformer is the most binding element in the region at 17% of hours, creating $24MM in congestion. Palmyra-Marblehead, not recommended by latest PJM-MISO IPSAC, still shows up as binding in 2024 and creates $11MM in congestion.

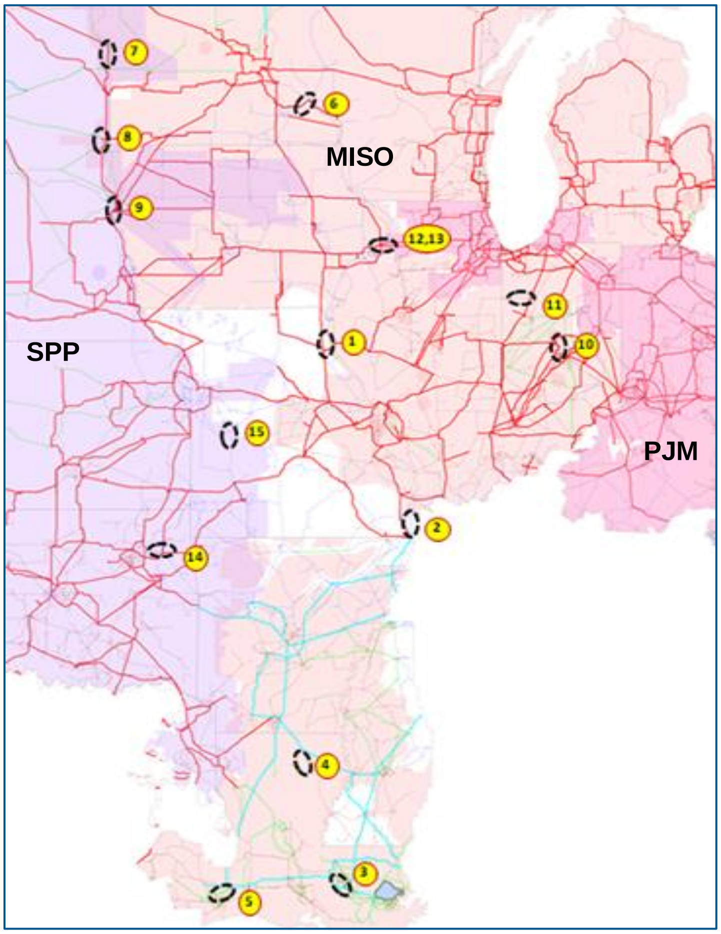
The SPP seams, unaddressed by the MISO-SPP IPSAC, continue to be congested. As described earlier, Overton transformer and Fairport-Hickory Creek are among the top elements causing cost in both markets. Raun-Tekamah also shows up in 2024 in MISO after failing to meet benefit/cost criteria for approval in 2019.

Top constraints in 2024 with binding hours and congestion costs are shown in Exhibit 4-6.

Exhibit 4-6 MISO Top Projected Constraints in 2024

Region	Index	Constrained Element	2024 – Base Case	
			Binding Hours (#)	Congestion Cost ($ MM)
MISO Central	1	Palmyra to Marblehead North Circuit – 1	388	11
MISO South	2	New Madrid Transformer – 2	4,142	513
	3	Addis to Tiger Circuit – 1	7,346	169
	4	Alto to Swartz Circuit – 1	1,756	113
	5	Helbig Bulk to Mclewis Circuit – 1	1,984	17
MISO West	6	Wabaco 161 to Alma Circuit – 1	1,822	51
	7	Big Stone to Browns Valley Circuit – 1	788	46
	8	Lawrence to Sioux Falls Circuit – 1	1,170	25
	9	Raun to Tekamah Circuit – 1	472	18
MISO-PJM Seams	10	Guion Transformer - N	1,482	24
	11	Goodland to Reynolds Circuit - 1	1,302	12
	12	Quad Cities to Rock Creek Circuit - 1	214	8
	13	Quad Cities to MEC Cordova Circuit - 1	36	3
MISO-SPP Seams	14	Kerr to Maid Circuit - 1	496	15
	15	Clinton to Truman Circuit - 1	366	9

Exhibit 4-7 Location of MISO Top Projected Constraints in 2024



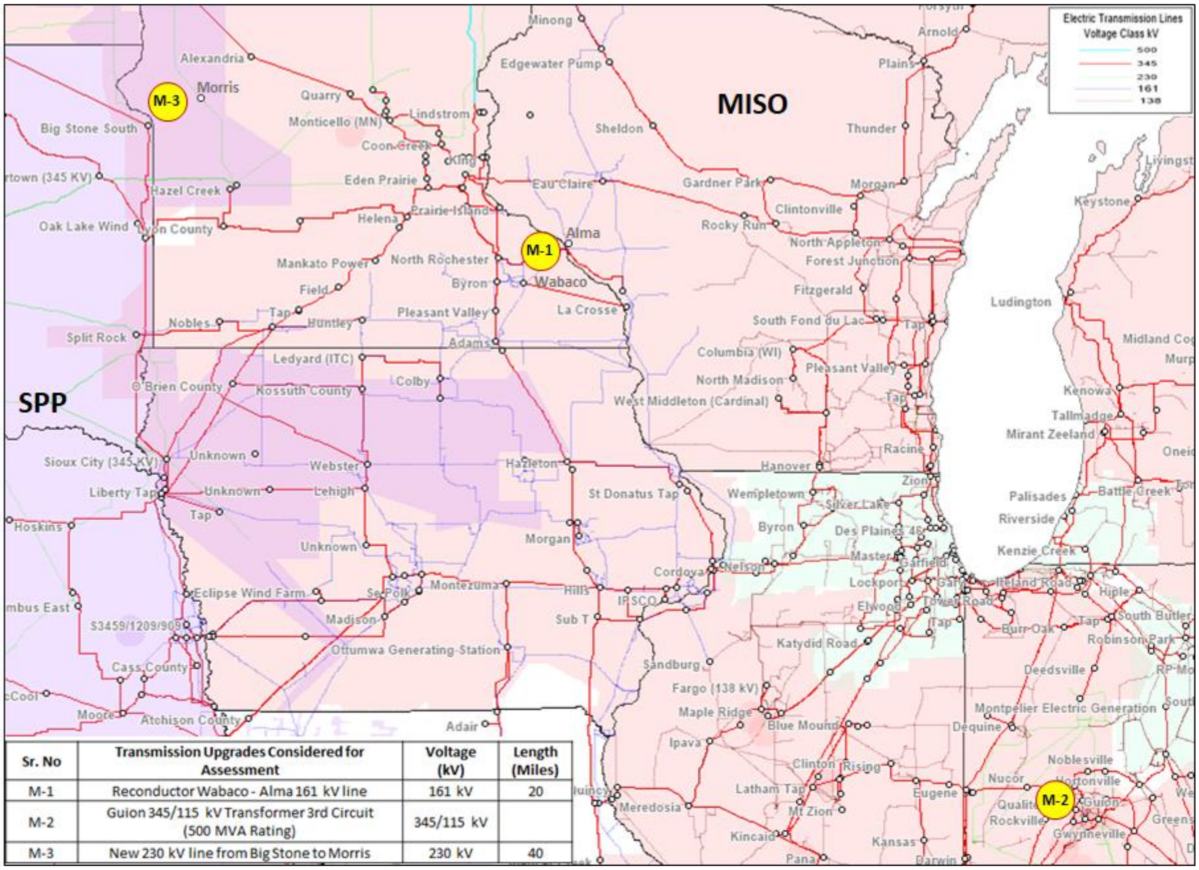
Map source: ABB Velocity Suite

4.3 Studied Transmission Upgrades

ICF targeted upgrades at these most binding constraints historically that still show up in our projections.

First, we identified the straightforward upgrade in Minnesota of continuing the reconductor project from Wabaco onwards to the Alma substation. While takeaway capacity at Wabaco is limited, Alma is much more connected to the rest of the regional grid, being at the nexus of two 345kV connections and three 161kV lines in addition to the connection with Wabaco. Our results confirm the hypothesis: we show that no further constraints in the area are aggravated, and that the second portion of the line is effective in reducing APC for the market and improves market pricing for wind, especially in Iowa and Minnesota. APC savings total $44MM in 2024 for a total upgrade cost of just $20MM estimated. This seems to us a logical, low-cost solution and does not require construction of any new lines.

Exhibit 4-8 Upgrades Studied in MISO



Sr. No	Transmission Upgrades Considered for Assessment	Voltage (kV)	Length (Miles)
M-1	Reconductor Wabaco - Alma 161 kV line	161 kV	20
M-2	Guion 345/115 kV Transformer 3rd Circuit (500 MVA Rating)	345/115 kV	
M-3	New 230 kV line from Big Stone to Morris	230 kV	40

Map source: ABB Velocity Suite

Second, we identified a possible upgrade on the second-most constrained element in western MISO around the Big Stone substation. Big Stone connects at 230kV to Blair and Browns Valley substations, and at 345kV to Ellendale and Brookings substations, all in South Dakota. Our modeling found that adding a third 230kV connection a short distance to Morris substation in Minnesota relieves the constraint between Big Stone and Browns Valley and allows improved power flows across the 345kV MVP lines. We estimate a construction cost of $40MM for the new line. The line proves highly economic, with APC savings of $41MM in the first year.

Third, we looked to eastern MISO and tested an upgrade at Guion transformer, which is the most frequently binding and costly constraint in Indiana in 2024. Adding a new 345/115kV circuit to the transformer removed the binding constraint and was shown to have benefits to the market and to wind producers, but the net effect for both was much smaller than expected. For a cost of $6MM, APC savings for the market total $16MM. We do not find that any one downstream constraint becomes binding in its place and could be included to improve the overall economic; rather congestion patterns adjust slightly and mute the impact. Nevertheless, an upgrade would be a net positive.

Exhibit 4-9 below shows the summarized results of the three transmission cases tested in MISO. By implementing the recommended upgrades, APC savings total $100MM and cost to serve load is reduced by

$48MM. The total capital cost of the three projects is estimated at only $66MM; net savings to consumers over the life of the projects would be high.

Exhibit 4-9 Summary of MISO Upgrade Results- Single Year Assessment (2024)

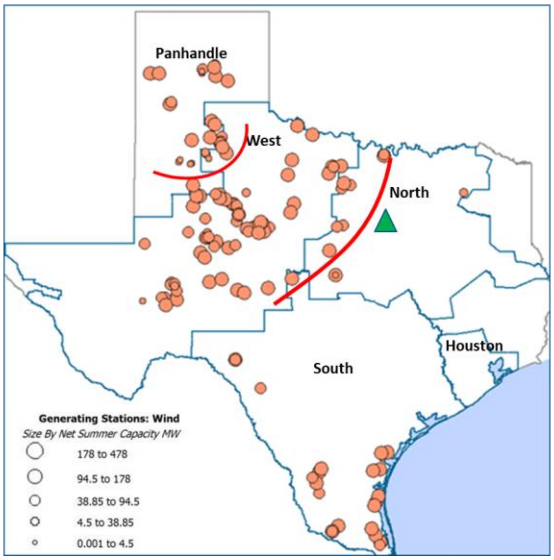
Upgrade ID	Upgrade	$MM Adj. Production Cost Savings	APC Benefit/cost Ratio for MISO	Est. Project Cost $MM
M-1	Wabaco-Alma 161kV Reconductor	44	22.2	20
M-2	Guion Transformer 345/115 3rd circuit (500 MVA)	16	26.0	6
M-3	Big Stone – Morris new 230kV line	41	10.1	40

ICF's assessment finds at least two upgrades that have meaningful positive impact for the market and for wind, but these address the top two constraints in the west, and beyond these we do not find any obvious solutions that would have a large impact. With these upgrades, significant basis remains. We believe large new projects may be needed in conjunction with continuous low-voltage upgrades to keep pace with the rapid wind and solar buildout and mitigate basis impact. This is a recommended area of further study.

5. Discussion: ERCOT

ERCOT has 22 GW of installed wind, the highest total of any market. About 16 GW, three-fourths of the total, is in ERCOT West zone, with just over 4 GW installed in the remote Panhandle sub-zone within West. Much of the rest is located in South zone, including about 3 GW in the coastal counties and the Lower Rio Grande Valley (LRGV), where wind patterns are markedly different from those inland (exhibiting strong daytime shape with less output overnight). Power is traded at four major hubs, one in each zone, with ERCOT North hub being the most liquid.

Exhibit 5-1 Location of Wind Projects and Typical Congestion Interfaces in ERCOT



Map source: ABB Velocity Suite

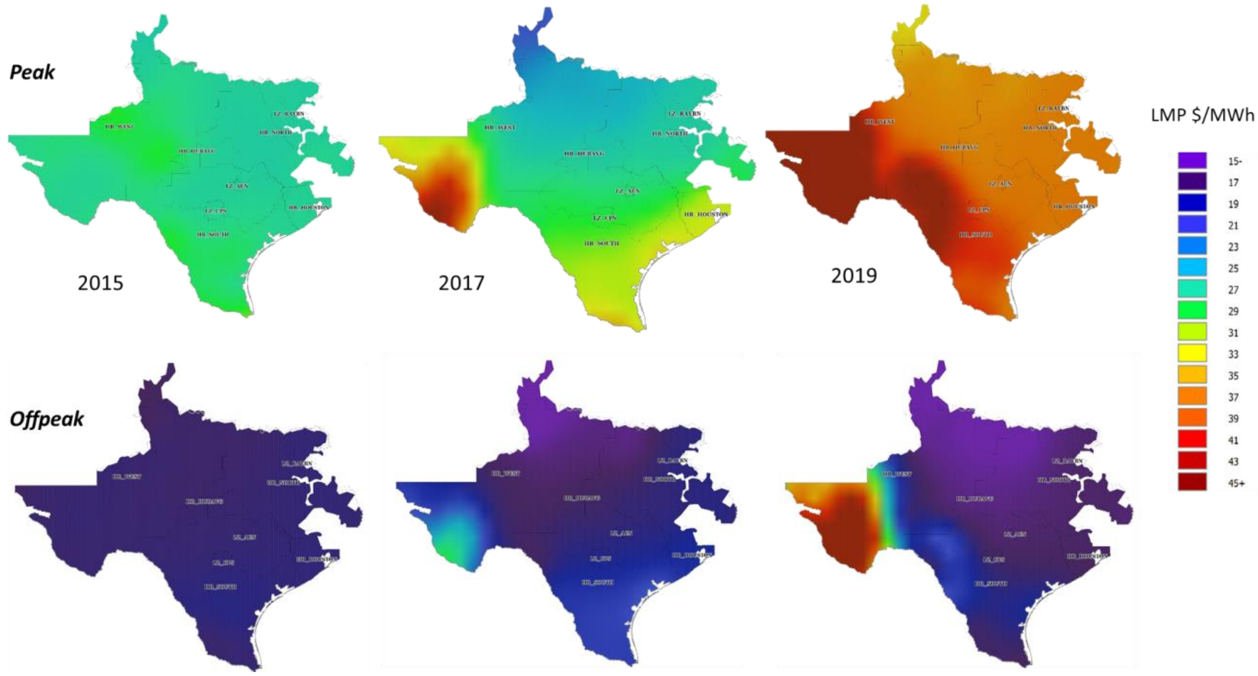
Historically, the major congestion issues relevant for wind have been ERCOT West-North interface, which is no longer a single monitored element[15] but has a series of constraints generally associated with it, and Panhandle-West interface, which in contrast is a single monitored interface with a stability limit. The West zone has only around 4 GW of average load, and the Panhandle currently has no load in ERCOT. The Houston zone is a major load center and is locally short of capacity, so this general northwest-to-southeast congestion pattern identified for wind is also characteristic of the market as a whole.

5.1 Historical Congestion 2015-2019

Congestion was mild in 2015, but has worsened in ERCOT somewhat over the past five years (on-peak shown in Exhibit 5-2 to illustrate trends; similar patterns shown in off-peak):

[15] In Oct 2020, after finalization of the study (Q4 2019), ERCOT began monitoring a West Export GTC. However, individual constraints, some of which are associated with lines monitored in the GTC, continue to be meaningfully congested on their own.

Exhibit 5-2 Historical Evolution of LMPs in ERCOT



Map source: ABB Velocity Suite; compiled by ICF using historical price data

The Competitive Renewable Economic Zone (CREZ), a $7B proactive transmission investment by ERCOT to open up the West and Panhandle for much greater wind development, was placed in service in 2013. CREZ built up almost 2000 circuit-miles of new 345kV lines and was designed to evacuate upwards of 18 GW of wind from the West. In 2015, there was still significant excess transmission capacity as a result of this investment, and nodal basis was very mild throughout the West and Panhandle. The top constraints centered around Houston followed by the LRGV, but overall congestion costs in the market were very small.

By 2017, the Houston and LRGV import constraints that were mild in 2015 became exacerbated as load grew but generation was primarily added in North and West zones (largely gas and wind). Also, 1.6 GW of wind was placed in service in the Panhandle in 2016 and 2017, bringing the total capacity to 4.2 GW and greatly exceeding the stability limit than was then at just 2.7 GW. This interface was the second-most binding element in 2017 after the Houston import limit. As of Dec 2019, no new wind plants have come online in the Panhandle since.

While the high-voltage CREZ lines still had plenty of excess capacity, the increase in flows from the West started exacerbating constraints on the low-voltage network required to deliver the power to load centers particularly in Dallas. Three of the top 10 constraints in 2017 were in this category, including two constraints at Wagley Robertson 138kV substation and Carrolton Northwest-Lakepointe 138kV. Both were approved for upgrades that are being placed in service in 2019. In the intervening years, these constraints led to growing West-North price separation.

Between 2017 and 2019, wind growth continued in the West but at a slower pace. Three trends changed congestion patterns throughout the market. First, the Houston Import Project, consisting of several large

345kV upgrades, came online in 2018 and eliminated the premium pricing in Houston and along the coastal South zones. The North-Houston import limit is no longer in the top 15 constraints as of 2019 after being the top constrain in 2017 with $174MM in cost.

Second, ERCOT added a second circuit between Alibates and Tule Canyon 345kV substations plus synchronous condensers that collectively increased the Panhandle export limit from 2.7 GW to 3.6 GW. Since no new wind came online during this period in the Panhandle, the nodal basis reduced somewhat from its peak, although the region is still oversupplied relative the 3.6 GW limit and has been in the top 2 constraints for the third year in a row.

Finally, the Far West emerged as major import-constrained area, having only a weak low-voltage network and explosive load growth (33% between 2017 and 2019) due to Permian oil and gas drilling. No wind exists in the current Far West "bubble", though the load growth is largely prevented from benefitting the rest of West because of the constraint. Yucca Drive-Gas Pad 138kV was the top constraint in 2018 with an immense $257MM in congestion rent, and Barilla-Fort Stockton 69kV is the top constraint in 2019 YTD.

5.2 Projected Congestion 2024

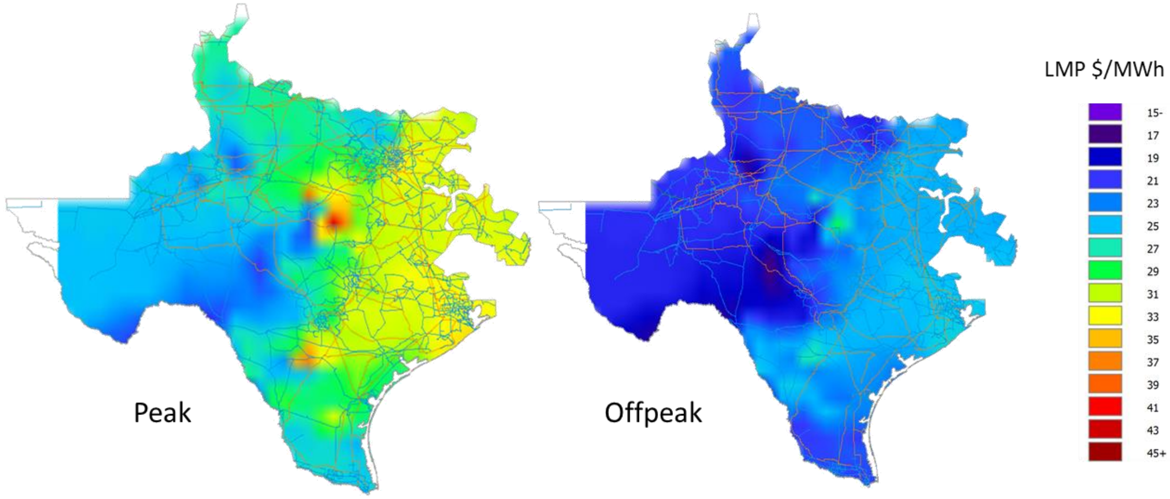
ICF implemented the following parameters in our modeling in 2024 according to our own internal assumptions with additional wind capacity projected by AWEA (showing 2019 for comparison). ICF implemented all currently approved transmission projects.

Exhibit 5-3 ICF Modeling Parameters in 2024 for ERCOT

Parameter	2019	2024
Installed Wind MW	22,047	33,912
Installed Solar MW	1,851	10,191
Peak Demand MW	74,820 (2019 actual)	83,661
Total Energy TWh	384.5 (est.)	445.3

ICF projected the following on-peak and off-peak congestion patterns for ERCOT in 2024:

Exhibit 5-4 Base Case LMP Projections for ERCOT in 2024



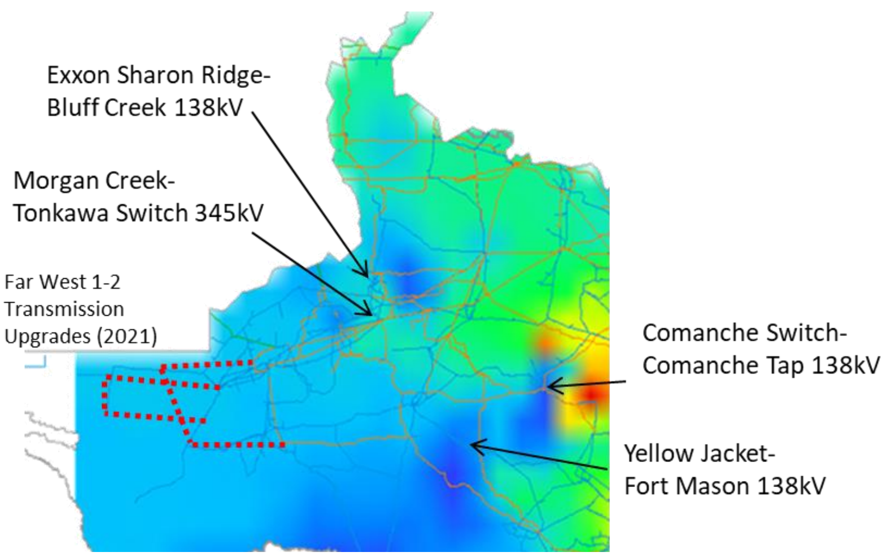
Map source: ABB Velocity Suite

Several notable transmission improvements occur between 2019 and 2024, but with the influx of wind and solar concentrated in the West, congestion interfaces spring up all over the map.

Far West

With the completion of two new major 345kV circuits in the Far West by 2021, the old import-constrained congestion interface west of Midland disappears. Instead, with over 8 GW of new renewable builds in the area, the Far West flips from import to export-constrained, and a new negative congestion interface appears that splits West zone in half. This expanded "far west" export bubble includes 11.6 GW of wind in 2024 in addition to 5.8 GW of solar. There are four main constraints within the West binding this area as shown in Exhibit 5-5.

Exhibit 5-5 Project Congestion - Far West



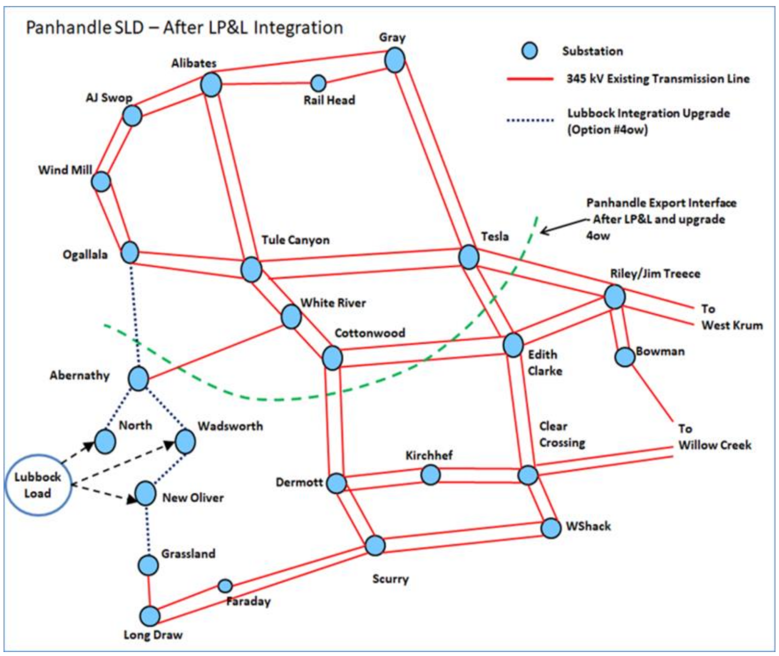
Map source: ABB Velocity Suite

Further south, the congestion interface continues to San Antonio and is bound by the Kendall-Cagnon and Kendal-Bergheim 345kV constraints. The congestion cost attributable to these five constraints totals $252MM in 2024.

Panhandle

In May 2021, Lubbock Power and Light's (LP&L) supply contract with Xcel in SPP ends, and the municipality will switch in to ERCOT territory. LP&L exists at the border of the current Panhandle interface. ERCOT will build a series of new lines from Ogallala to Long Draw to integrate LP&L, giving another outlet for Panhandle wind plus around 450 MW of native load to serve. The interface limit is expected to go from 4 GW today to 4.8 GW in 2021.

Exhibit 5-6 Panhandle Transmission Map with LP&L Integration



Source: ICF using information from ERCOT

Despite the planned additions of 793 MW of wind and 442 MW of solar in the Panhandle, this increased export limit will significantly ease congestion to the rest of West zone. Indeed, basis in the Panhandle is projected to be less negative than that in the Far West in 2024 under the Base Case assumptions.

West-North

The northern part of West zone, on the positive side of Morgan Creek-Tonkawa Switch and Comanche Switch-Comanche Tap, is quite constrained with respect to North zone than the rest of West. West Hub buses exist on both sides of this interface. The only major constraint that still separates North from all of West is the West TNP – TI TNP 138kV constraint near Dallas. This has been a top-10 constraint since 2018 and by 2024 is the most costly in the market at $187MM congestion rent.

LRGV

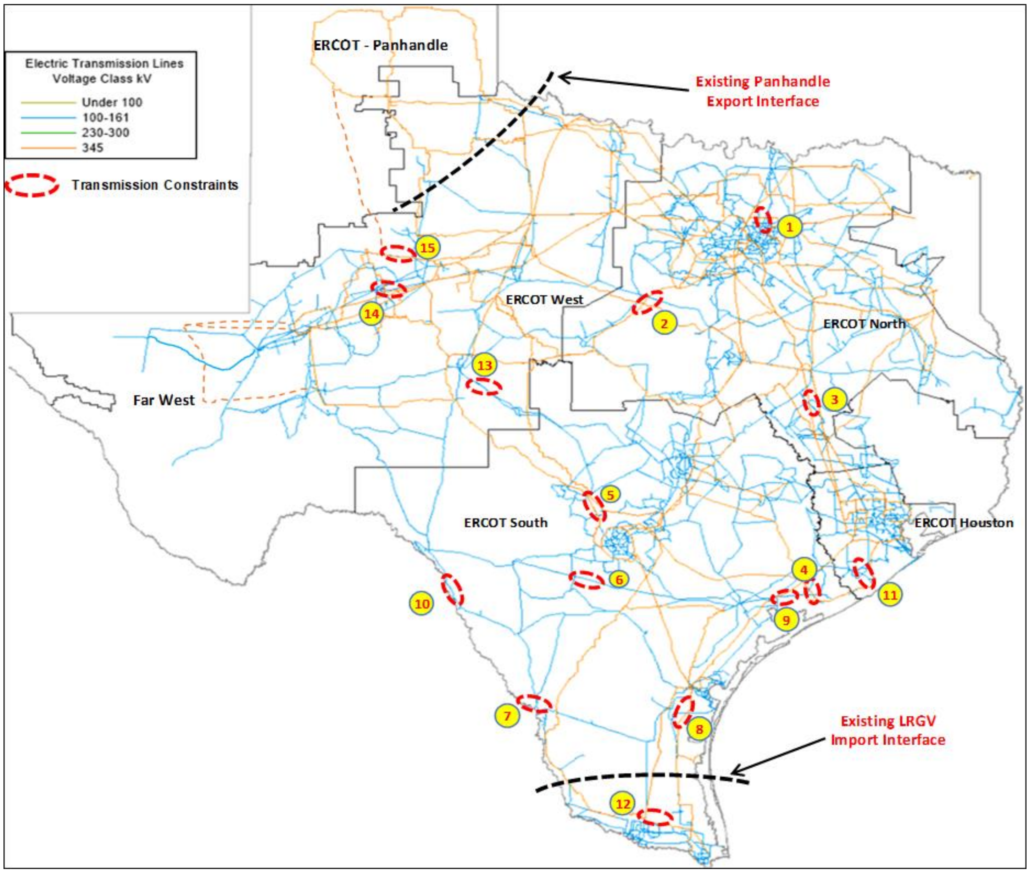
While the LRGV has historically been an import-constrained zone experiencing positive congestion, by 2024, with the addition of 1.7 GW of wind and 200 MW of solar, the region flips to export-constrained. Bonilla Tap-N Edinburg 345kV within the LRGV is a top-15 market constraint with $12MM in cost. Further north, Blessing-Lolita 138kV and STP-Hillje 345kV are more costly at $156MM and $16MM respectively. Like the Far West, the "bubble" contained within the export constraint is wider than the previous import constraint, and brackets more renewable capacity. The entire coastal South is at a discount to South Hub, compared to its historical premium.

Top constraints in 2024 with binding hours and congestion costs are shown in Exhibit 5-7.

Exhibit 5-7 ERCOT Top Constraints in 2024

Region	Index	Constrained Element	Voltage (kV)	2024 - Base Case	
				Binding Hours (#)	Congestion Cost ($ MM)
ERCOT North	1	West TNP - TI TNP Circuit	138	1500	187.1
	2	Comanche Switch - Comanche Tap Circuit	138	2034	54.8
	3	Jack Creek - Twin Oak Circuit	345	1307	37.6
ERCOT South	4	South Texas to Hillje Circuit	345	3408	155.7
	5	a. Bergheim - Kendall 345 kV Circuit b. Cagnon-Kendal 345 kV Circuit	345	4674	146.3
	6	Moore Switch - Big Foot Circuit	138	2079	30.5
	7	Milo - Laredo North Circuit	138	891	21.7
	8	Celanese Bishop - Nelson Sharpe Circuit	138	2734	16.1
	9	Blessing - Lolita Circuit	138	1407	15.6
	10	Escondido - Eagle Hydro Tap Circuit	138	942	15.5
	11	Jones Creek - Velasco Circuit	138	522	13.9
	12	Bonilla Tap - N.Edinburg Circuit	345	473	11.7
ERCOT West	13	Yellow Jacket - Fort Mason Circuit	138	1597	24.4
	14	Morgan Creek - Tonkawa Switch Circuit	345	490	17.5
	15	Exxon Sharon Ridge-Bluff Creek Circuit	138	1037	8.9
	16	Panhandle Interface	--	82	1.0

Exhibit 5-8 Location of ERCOT Top Constraints in 2024



Map source: ABB Velocity Suite

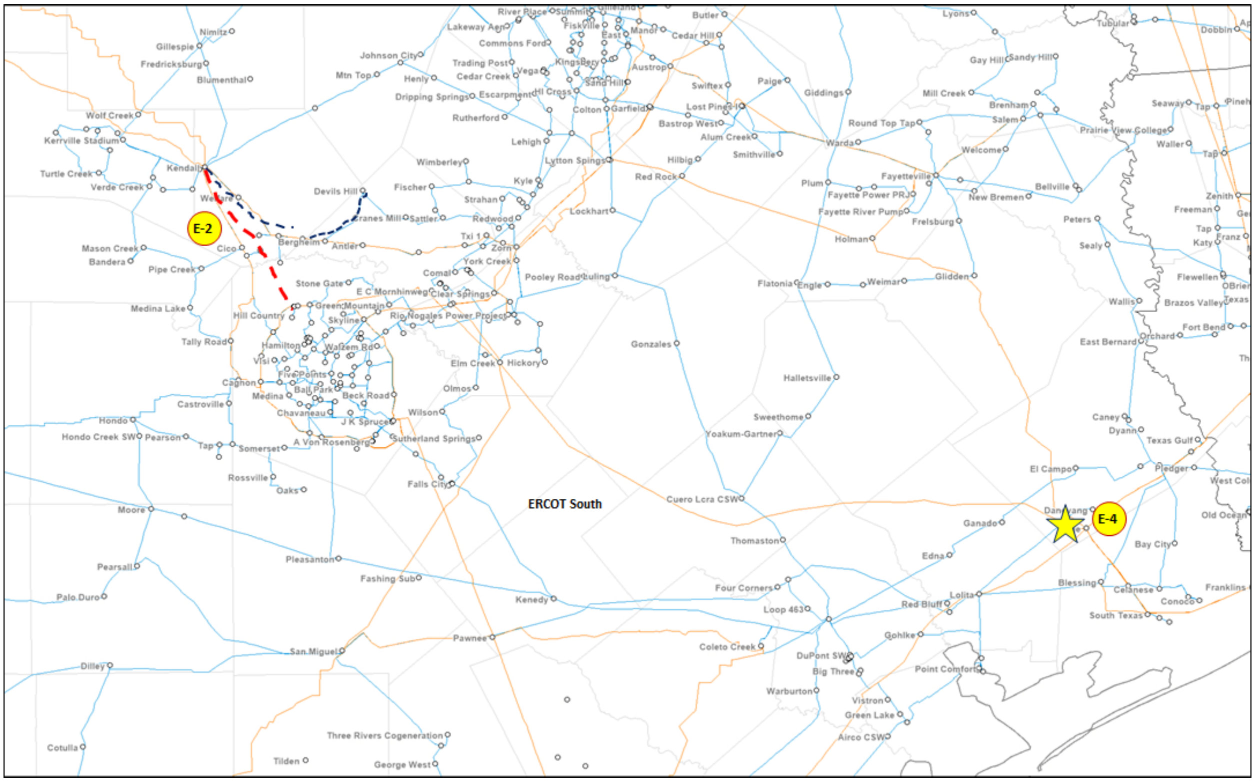
5.3 Studied Transmission Upgrades

ICF targeted upgrades for the top four most costly constraints in the market. Two of these upgrades have previously been evaluated by ERCOT but have not yet been approved.

The two constraints ERCOT has evaluated are both in South zone. First, the STP-Hillje 345kV constraint at the border of South and Houston zones near the coast is the most frequently congested constraint at 39% of hours in 2024. In 2018, ERCOT evaluated an upgrade to loop in the STP-Elm Creek double circuit at Hillje substation in the Regional Transmission Plan (RTP) and found it economic for 2023 in-service, but the project has not yet moved forward for reasons unclear. The 2019 RTP again recommended the project with a slightly different configuration. Project cost is estimated at under $10MM.

Our modeling indicates that this upgrade would remove the binding constraint at STP-Hillje, and only a portion of the congestion would be moved to the nearby Blessing-Lolita 138kV constraint (+$20MM congestion cost, vs $156MM removed from the original constraint). The benefits all flow to South zone wind, including the LRGV region.

Exhibit 5-9 Upgrades Studied in ERCOT South



Map source: ABB Velocity Suite

The second constraint is located at Kendall substation (actually two constraints comprising Kendall-Bergheim and Kendall-Cagnon, both 345kV) near San Antonio. This forms the southern border of the projected 2024 “far west” congestion bubble. ERCOT proposed a series of upgrades incorporating a new line from Kendall to Hill Country 345kV, a new line Bergheim-Devils Hill 138kV, and other line upgrades and transformer equipment. ERCOT’s analysis in 2018 showed that the package yielded economic benefits but insufficient to meet benefit/cost criteria. However, the ERCOT analysis included significantly less renewable capacity than the 2024 Base Case.

With the higher renewable levels, we project that production cost savings from the upgrade would be $38MM in 2024 compared to the $20-25MM in savings that ERCOT projected[16]. The upgrades are sufficient to relieve all constraints at Kendall, totaling $146MM. While other constraints in the market pick up some congestion ($41MM in total), the production benefit/cost is projected to be 1.6 and therefore likely to be approved.

The other two upgrades evaluated are in North zone. As mentioned previously, the West TNP-TI TNP 138kV line is the costliest constraint in 2024 at $187MM. West TNP-TI TNP is located near several other 138kV import constraints into Dallas that have consistently been approved for upgrades over the past several years:

- Wagley Robertson-Blue Mound 138kV (upgrade 2019)

[16] It is worth noting that even ERCOT’s assessment of $20-25MM in benefits yields benefit/cost ratio of 0.9-1.1; very close to the approval criteria.

- Carrolton NW-Lakepointe 138kV (upgrade 2020)
- Lewisville-Jones St 138kV (upgrade 2021)
- Alliance-Hicks 138kV (upgrade 2023)

We therefore find it likely on the face of it that a rebuild of West TNP-TI TNP will follow, especially as it has moved up the list of actual observed constraints already in 2018 and 2019. Upgrades on this line were studied in the 2019 RTP, but did not meet economic criteria. With the much greater renewable buildout assumed in the ICF Base Case than the 2019 RTP (1.8 GW of new solar and 5.4 GW of new wind in RTP vs 8.3 GW of solar and 11.9 GW of wind in the ICF Base Case), our modeling shows the constraint becoming very binding and an upgrade to be highly beneficial. Because of the low upgrade cost, the projected benefit/cost ratio is high.

Finally, we tested solutions to the Comanche Switch-Comanche Tap 138kV constraint at the boundary of West and North zones. A short, new 138kV line from Comanche to Hasse is found to resolve the constraint and only marginally increase congestion at other constraints, primarily West TNP-TI TNP. The benefit/cost ratio is also found to be very high for this upgrade.

ICF's assessment tested each upgrade individually. While each was found to be highly economic, the cost savings for each project were slightly attenuated by increased congestion at the other major constraints. Solving all of these four constraints could result in even larger savings. Further, we did not test a few of the more minor constraints stressing the LRGV; transmission upgrades here are highly likely in any case to support growing load from the LNG export industry.

The main effect of the ERCOT upgrades is to transfer revenue from congestion revenue rights (CRR) holders to generators. Under the Base Case, ERCOT takes in a lot more money from prices at load than it pays out to generators because of discounted pricing in the West; CRR holders profit the difference. Based on their protocols and history, ERCOT is expected to consider reduced congestion rent a positive. Additionally, apart from Kendall-Bergheim, the other three upgrades cost an estimated $10MM or less, and therefore a. do not require Board or even RPG approval, and b. are candidates for direct sponsorship by generators should they otherwise not succeed in the transmission planning process.

Exhibit 5-10 Summary of ERCOT Upgrade Results-- Single Year Assessment (2024)

Upgrade ID	Upgrade	$MM Production Cost Savings	Production Benefit/cost for ERCOT	Est. Project Cost $MM
E-1	Comanche-Hasse 138kV New Line	12	23.8	5
E-2	Kendall-Bergheim Area Upgrades	38	1.6	230
E-3	Rebuild West TNP-TI TNP 138kV Circuit	16	15.4	10
E-4	South Texas Project - Elm Creek Dbckt Loop-in at Hillje	7	7.6	9

6. Appendices

The tables below present the comparison of ICF's demand assumptions with that of annual transmission study of ERCOT, SPP and MISO. The comparison is done through 2024 for incremental peak and energy demand.

Table 6-1: Peak Demand Assumption Comparison Between ICF and ERCOT's 2019 RTP Report

Year	ICF Demand (MW)					ERCOT 2019 RTP Demand Assumption				
	ERCOT-Total	ERCOT-N	ERCOT-H	ERCOT-S	ERCOT-W	ERCOT-Total	ERCOT-N	ERCOT-H	ERCOT-S	ERCOT-W
	Peak (MW)	Peak (MW)	Peak (MW)	Peak (MW)	Peak (MW)	Peak (MW)	Peak (MW)	Peak (MW)	Peak (MW)	Peak (MW)
2021	78,824	28,492	21,930	21,616	6,786	81309	28715	24377	21637	6580
2024	83,661	29,549	23,369	23,046	7,697	86053	29830	25933	23037	7254

Table 6-2: Peak Demand Assumption Comparison Between ICF and SPP 2019 ITP Report

SPP Total Peak Demand (GW)			
Year	ICF Assumption	SPP 2019 ITP Assumption[1]	
		Future 1	Future 2
2021	53	53	53
2024	54	53	55

1. SPP ITP 2019 presents coincidental peak demand while ICF assumptions presents non-coincidental demand in above table

Table 6-3: Peak Demand Assumption Comparison Between ICF and MISO MTEP19 Report

Demand Assumptions Through 2024 (GW)		
Year	ICF Assumptions (GW)	MISO METP19 AFC Case (ICF Estimate)
2019	124.8	124.8
2021	127.1	126.8
2024	130.4	129.7

1. For MISO METP16, average growth rate of 0.59% is applied to get peak demand of 2021 and 2024 in above table

The tables below present the comparison of ICF's firm retirement assumptions with that of annual transmission study of ERCOT, SPP and MISO. The comparison is done through 2024. Please note ICF's assumption presented below includes economic retirements based on ICF's proprietary IPM modeling and represent preliminary projections.

Table 6-4: Firm Retirements Assumption Comparison Between ICF and ERCOT

Retirements and Mothballed Assumptions (GW) through 2024		
Type	ICF Assumptions	ERCOT 2019 RTP Assumptions
2021	1.9	3.5
2024	2.4	3.5

Table 6-5: Firm Retirements Assumption Comparison Between ICF and SPP

Retirements and Mothballed Assumptions Through 2024 (GW)			
Type	**ICF Assumptions**	**SPP ITP 2019 Future 1**	**SPP ITP 2019 Future 1**
Coal	2.8	2.5	2.7
Gas	1.2	3.1	4.2
Total	**4.0**	**5.6**	**6.9**

Table 6-6: Firm Retirements Assumption Comparison Between ICF and MISO

Retirements and Mothballed Capacity (GW)		
Type	**ICF Assumptions through 2024**	**MISO METP19 AFC Assumption through 2033**
Coal	3.5	19
Gas	0.7	16
Total	**4.2**	**35**

Note: MISO only reports builds/retirements by 2033. Builds and retirements in the interim years are not clear

Finally, the table below shows a comparison of ICF and the ISO's natural gas price assumptions.

Table 6-7: Natural Gas Price Comparison

Henry Hub $/MMBtu	ICF Assumptions	MISO MTEP 2019 – Estimated	SPP ITP 2019 – Estimated	ERCOT RTP 2019
2020	2.5	3.3	3.2	3.2
2021	2.5	3.4	3.8	3.2
2022	2.8	3.5	4.0	3.3
2023	3.2	3.7	4.1	3.6
2024	**3.2**	**3.9**	**4.2**	**3.8**

Note: MISO and SPP only show a line graph for natural gas prices; ICF estimated the values. ERCOT reports values in a table.