

**ACORE Comments on the U.S. Department of Energy’s National Transmission Needs
Study: Draft for Consultation and Public Comment**

September 8, 2026

ACORE greatly appreciates the opportunity to submit these comments on the 2026 National Transmission Needs Study, Draft for Public Consultation and Comment (“Draft Needs Study”) issued by the Department of Energy (DOE). ACORE is a 501(c)(3) national nonprofit organization that unites finance, policy and technology to accelerate the transition to a clean energy economy. Our members are collectively responsible for 90 percent of the utility-scale clean energy capacity growth in the U.S.

As DOE explains, this study has multiple beneficial uses, including informing “overall industry and government planning efforts to reduce transmission congestion and capacity constraints that adversely affect consumers.”¹ ACORE strongly agrees that “holistic, multi-value transmission planning can enable transmission solutions to meet multiple planning objectives and lead to a more efficiently planned, cost-effective transmission system.”²

At this time of significant pressure on energy costs, the final National Transmission Needs Study has the potential to be an important resource for identifying the most cost-effective transmission and advanced transmission technologies. ACORE appreciates the information and data provided in the Draft Needs Study and recommends additions and revisions to further improve the value of the final version.

I. Overall Value and Purpose of the Needs Study

ACORE supports DOE’s definition of “needs” as “the existence of present or expected electric transmission capacity constraints or congestion in a geographic area,”³ and the definition of capacity constraints as “limits that reduce operational reliability of the power system; power transfer capability or capacity limits between neighboring regions that reduce resilience or

¹ Draft Needs Study at 2.

² *Ibid.*

³ *Ibid* at 9.

increase production costs; and limits on the ability of low-cost generation to be delivered to demand.”⁴ These definitions are important as they capture the multiple values of transmission.

ACORE commends DOE for providing valuable information and documenting the full range of benefits provided by transmission, especially interregional transmission. These include the following, as described in section *III.a. Role of Transmission in the Power Sector*:⁵

- Improving reliability by accessing diversity in load, generation, and weather patterns within and between regions
- Lowering congestion costs and losses, which in turn can reduce electricity prices.
- Hastening the interconnection of resources in the backlogged queues.
- Reducing generation curtailment by delivering power to a wider geographic area.
- Increasing employment, tax revenues, and other economic development benefits.

These benefits are further elaborated in section *V. Historical Transmission System Benefits and Constraints*, where DOE reiterates that transmission “provides significant value to energy consumers, both in reducing costs during typical operations and improving reliability during periods when the grid is the most stressed,” and plays important “roles in enhancing reliability in geographically isolated locations, improving resilience during severe weather or cyber or physical attacks, and enhancing resource adequacy.”⁶ DOE also finds that interregional transmission delivers power when “grid regions experience peak stress periods at different times” and has the “highest potential to reduce the average wholesale price of electricity.”⁷

While this documentation of the multiple values of transmission is important, ACORE recommends additions or revisions to expand the value of the final Needs Study in the next section.

⁴ *Ibid* at 11.

⁵ *Ibid.* at 8.

⁶ *Ibid.* at 36.

⁷ *Ibid.* at 36 – 37.

II. ACORE Recommended Additions and Revisions to the Needs Study

A. Assessment of Needs

While the Needs Study accurately describes the value of transmission in reducing electricity prices and improving reliability, along with other economic and security benefits, the study is missing a documented assessment of the present and future transmission needs within and between regions.

DOE states at the beginning of the Draft Needs Study that it “is committed to the regular development” of a Needs Study “to determine high-priority national electric transmission needs—*specifically, to identify geographic areas where the bulk power grid would benefit from new, uprated, or upgraded transmission facilities*”⁸ and to do so under “future transmission system considerations, including forecasted changes in load growth, generation mix, and anticipated generator retirements, among others,”⁹ The Draft does not provide such an comprehensive assessment other than a brief summary of the regional transmission studies (many of which are out of date).

In contrast, the 2023 National Transmission Needs Study (“2023 Needs Study”), provides an assessment of transmission needs under varied scenarios for load growth and the generation mix, as shown in the tables below for both regional and interregional transmission.¹⁰ **The Final Needs Study should incorporate an updated version of these or similar tables.**

⁸ *Ibid* at 1.

⁹ *Ibid* at 2.

¹⁰ US Department of Energy, *National Transmission Needs Study* (Oct. 2023) at 21, https://www.energy.gov/sites/default/files/2023-12/National%20Transmission%20Needs%20Study%20-%20Final_2023.12.1.pdf.

Table VI-3. Median of regional transmission deployment results for each study scenario group in 2030, 2035, and 2040. Both new transmission in TW-mi and percent growth from 2020 system are shown.

Region	2020 TW-mi	Scenario Group	New in 2030		New in 2035		New in 2040	
			TW-mi	% Growth	TW-mi	% Growth	TW-mi	% Growth
CONUS	85.6	Mod/Mod	11.6	14%	17.0	20%	20.9	24%
CONUS	85.6	Mod/High	23.4	27%	54.5	64%	42.2	49%
CONUS	85.6	High/High	33.2	39%	109.8	128%	123.0	144%
California	4.29	Mod/Mod	0.06	1.5%	0.07	1.6%	0.08	1.8%
California	4.29	Mod/High	0.09	2.1%	0.12	2.8%	0.12	2.9%
California	4.29	High/High	0.05	1.1%	0.16	3.7%	0.23	5.4%
Mountain	3.48	Mod/Mod	1.46	42.1%	1.66	47.9%	1.86	53.5%
Mountain	3.48	Mod/High	2.28	65.5%	3.14	90.4%	2.88	82.9%
Mountain	3.48	High/High	3.12	89.7%	6.00	173%	7.69	221%
Northwest	15.24	Mod/Mod	0.03	0.2%	0.04	0.3%	0.08	0.5%
Northwest	15.24	Mod/High	0.07	0.4%	0.54	3.5%	0.00	0.0%
Northwest	15.24	High/High	0.62	4.1%	4.71	30.9%	8.54	56.1%
Southwest	5.66	Mod/Mod	0.41	7.3%	0.63	11.2%	0.78	13.7%
Southwest	5.66	Mod/High	0.93	16.5%	1.87	33.0%	0.81	14.3%
Southwest	5.66	High/High	2.75	48.7%	6.69	118%	7.64	135%
Texas	6.43	Mod/Mod	2.78	43.2%	4.35	67.7%	5.68	88.3%
Texas	6.43	Mod/High	6.04	93.9%	9.00	140%	9.60	149%
Texas	6.43	High/High	3.33	51.8%	7.27	113%	8.72	136%
Delta	3.36	Mod/Mod	0.01	0.2%	0.15	4.6%	0.40	12.0%
Delta	3.36	Mod/High	0.39	11.5%	1.65	49.2%	1.37	40.8%
Delta	3.36	High/High	2.98	88.7%	7.76	231%	8.79	262%
Florida	2.97	Mod/Mod	0.00	0.0%	0.08	2.7%	0.15	5.0%
Florida	2.97	Mod/High	0.06	2.1%	0.81	27.3%	1.04	35.1%
Florida	2.97	High/High	0.01	0.3%	0.73	24.4%	1.04	34.9%
Mid-Atlantic	14.60	Mod/Mod	0.56	3.9%	0.96	6.5%	1.11	7.6%
Mid-Atlantic	14.60	Mod/High	1.09	7.5%	3.28	22.5%	3.61	24.7%
Mid-Atlantic	14.60	High/High	2.49	17.1%	8.84	60.5%	11.69	80.1%
Midwest	11.92	Mod/Mod	1.13	9.5%	2.26	19.0%	3.40	28.5%
Midwest	11.92	Mod/High	3.71	31.2%	13.34	112%	16.22	136%
Midwest	11.92	High/High	7.73	64.8%	20.70	174%	23.40	196%
New England	1.94	Mod/Mod	0.02	0.9%	0.03	1.6%	0.05	2.4%
New England	1.94	Mod/High	0.05	2.5%	0.10	5.2%	2.72	140%
New England	1.94	High/High	0.37	18.9%	2.44	126%	2.98	154%
New York	0.82	Mod/Mod	0.00	0.0%	0.00	0.0%	0.00	0.0%
New York	0.82	Mod/High	0.00	0.0%	0.00	0.0%	0.06	7.6%
New York	0.82	High/High	0.10	12.5%	0.38	46.1%	0.41	50.4%
Plains	6.97	Mod/Mod	1.56	22.4%	2.93	42.1%	3.93	56.3%
Plains	6.97	Mod/High	3.52	50.5%	8.32	119%	6.31	90.5%
Plains	6.97	High/High	6.88	98.7%	28.47	408%	31.26	449%
Southeast	8.90	Mod/Mod	0.55	6.2%	1.09	12.2%	1.58	17.7%
Southeast	8.90	Mod/High	2.83	31.8%	6.82	76.6%	6.04	67.9%
Southeast	8.90	High/High	2.68	30.1%	9.11	102%	11.46	129%

Table VI-4. Median regional transfer capacity results for each scenario group in 2030, 2035, and 2040. Both new transfer capacity in GW and percent growth from 2020 system are shown.

Regional Pair	2020 GW	Scenario Group	New in 2030		New in 2035		New in 2040	
			GW	% Growth	GW	% Growth	GW	% Growth
CONUS	109	Mod/Mod	15.5	14%	27.5	25%	37.6	34%
CONUS	109	Mod/High	33.2	30%	124.6	114%	239.4	219%
CONUS	109	High/High	151.5	139%	449.0	412%	509.5	467%
California – Mountain	2.12	Mod/Mod	0.31	14.7%	0.96	45.4%	1.80	84.8%
California – Mountain	2.12	Mod/High	0.58	27.3%	1.87	88.1%	4.97	235%
California – Mountain	2.12	High/High	1.21	57.0%	2.75	130%	4.31	204%
California – Northwest	5.15	Mod/Mod	0.00	0.0%	0.00	0.0%	0.00	0.0%
California – Northwest	5.15	Mod/High	0.00	0.0%	0.13	2.5%	0.00	0.1%
California – Northwest	5.15	High/High	0.25	4.8%	1.28	24.9%	1.94	37.7%
California – Southwest	5.23	Mod/Mod	0.00	0.0%	0.14	2.7%	0.22	4.3%
California – Southwest	5.23	Mod/High	0.05	0.9%	0.31	5.9%	5.09	97.3%
California – Southwest	5.23	High/High	1.90	36.4%	5.31	102%	6.89	132%
Mountain – Northwest	12.7	Mod/Mod	0.00	0.0%	0.09	0.7%	0.51	4.0%
Mountain – Northwest	12.7	Mod/High	1.08	8.5%	3.30	26.0%	0.00	0.0%
Mountain – Northwest	12.7	High/High	6.25	49.2%	25.7	202%	39.2	308%
Mountain – Southwest	4.06	Mod/Mod	0.04	0.9%	0.09	2.2%	0.38	9.5%
Mountain – Southwest	4.06	Mod/High	0.37	9.1%	1.65	40.6%	1.70	41.7%
Mountain – Southwest	4.06	High/High	2.08	51.2%	5.24	129%	6.06	149%
Mountain – Plains	0.92	Mod/Mod	0.36	39.1%	0.94	102%	1.40	152%
Mountain – Plains	0.92	Mod/High	0.79	85.4%	2.64	287%	11.9	1,290%
Mountain – Plains	0.92	High/High	6.10	663%	19.3	2100%	29.2	3,170%
Plains – Southwest	0.40	Mod/Mod	0.69	172%	1.16	290%	1.48	370%
Plains – Southwest	0.40	Mod/High	2.53	631%	3.66	914%	13.1	3,280%
Plains – Southwest	0.40	High/High	5.54	1380%	13.0	3,240%	14.4	3,600%
Plains – Texas	0.82	Mod/Mod	0.02	3.0%	0.49	60.0%	0.91	111%
Plains – Texas	0.82	Mod/High	1.15	140%	9.84	1,200%	14.6	1,780%
Plains – Texas	0.82	High/High	14.3	1750%	28.9	3,520%	34.9	4,260%
Delta – Midwest	3.00	Mod/Mod	0.00	0.0%	0.00	0.0%	0.00	0.0%
Delta – Midwest	3.00	Mod/High	0.00	0.0%	0.00	0.0%	0.00	0.0%
Delta – Midwest	3.00	High/High	0.10	3.2%	0.91	30.4%	1.32	44.2%
Delta – Plains	4.76	Mod/Mod	0.00	0.0%	0.35	7.4%	0.73	15.3%
Delta – Plains	4.76	Mod/High	4.89	103%	19.7	414%	0.00	0.0%
Delta – Plains	4.76	High/High	20.7	434%	48.5	1020%	55.3	1160%
Delta – Southeast	5.92	Mod/Mod	0.00	0.0%	0.00	0.0%	0.00	0.0%
Delta – Southeast	5.92	Mod/High	0.92	15.6%	5.10	86.2%	10.7	181%
Delta – Southeast	5.92	High/High	10.1	171%	33.9	572%	37.7	637%

DOE explains the absence of such a needs assessment by stating that “[l]ong-term projections for many of these factors are rapidly evolving in 2026, such as expected load growth driven by large loads and data centers. Consequently, the nationwide modeling studies published

at the time of writing this report may not accurately reflect the current landscape of future energy markets.”¹¹

A standard practice for addressing such future uncertainty is to use multiple scenarios to identify the range of future needs. DOE does not deny the existence of expansive transmission needs, concluding that “the need is substantial for investment in transmission, including interregional connections through 2050.”¹² An analysis of such needs is an essential component of the final version of this study. DOE can use many of the studies it cites in the Draft Needs Study — namely the DOE’s National Transmission Planning Study,¹³ National Lab of the Rockies’ Standard Scenarios¹⁴, and the North American Electric Reliability Corporation (NERC) Interregional Transfer Capability Study,¹⁵ which are highlighted in Section VII of the Draft Needs Study — to develop such a future needs assessment, inclusive of updates and expansion of these data as described in the next section.

B. Updates and Expansion of Certain Data

The Draft Needs Study presents the results of a 2025 Lawrence Berkeley National Laboratory (LBNL) analysis of the value of transmission as reflected in price differentials, showing the average value of interregional and regional lines from 2012 through 2023.¹⁶ DOE should in addition or instead utilize LBNL’s newly available tool which updates these data

¹¹ *Ibid* at 83.

¹² *Ibid* at 82.

¹³ Department of Energy, *The National Transmission Planning Study*, (Oct. 2024), <https://www.energy.gov/gdo/national-transmission-planning-studyhttps://www.energy.gov/sites/default/files/2024-10/NationalTransmissionPlanningStudy-ExecutiveSummary.pdf>.

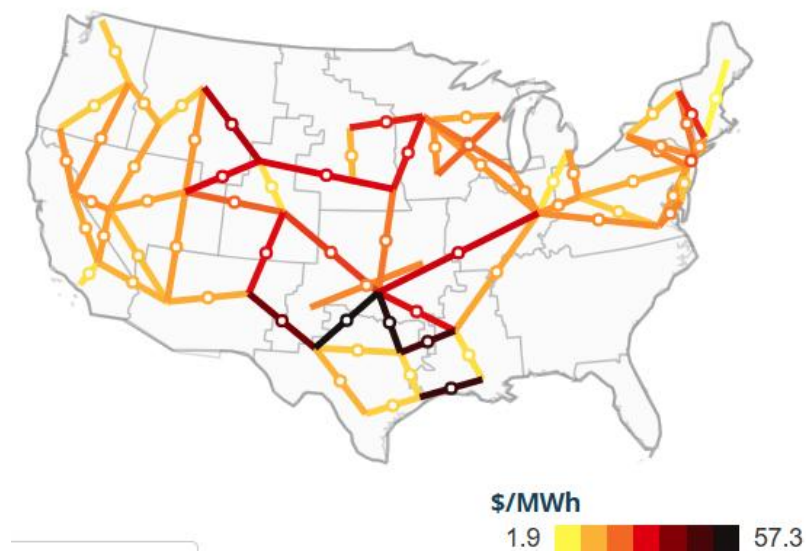
¹⁴ Gagnon, P., Pham, A., Cole, W., Hamilton, A., National Lab of the Rockies, *2024 Standard Scenarios Report: A U.S. Electricity Sector Outlook* (Dec. 2024), <https://docs.nlr.gov/docs/fy25osti/92256.pdf>. DOE cites this report under the former name, National Renewable Energy Laboratory and uses an incorrect URL in the Draft Needs Study.

¹⁵ North American Electric Reliability Corporation, *Interregional Transfer Capability Study - Final Report* (Nov. 2024) at xv: https://www.nerc.com/globalassets/initiatives/itcs/itcs_final_report.pdf

¹⁶ Julie Mulvaney Kemp, et al., Lawrence Berkeley National Laboratory, *Electric transmission value and its drivers in United States power markets*, https://eta-publications.lbl.gov/sites/default/files/2025-09/task_1_empricalvalue_and_drivers_formatted.pdf

through 2025 for the same interfaces.¹⁷ Using more recent data will help distinguish this Draft Needs Study from the previously published 2023 Needs Study, which used data for this same analysis from 2012-2022.

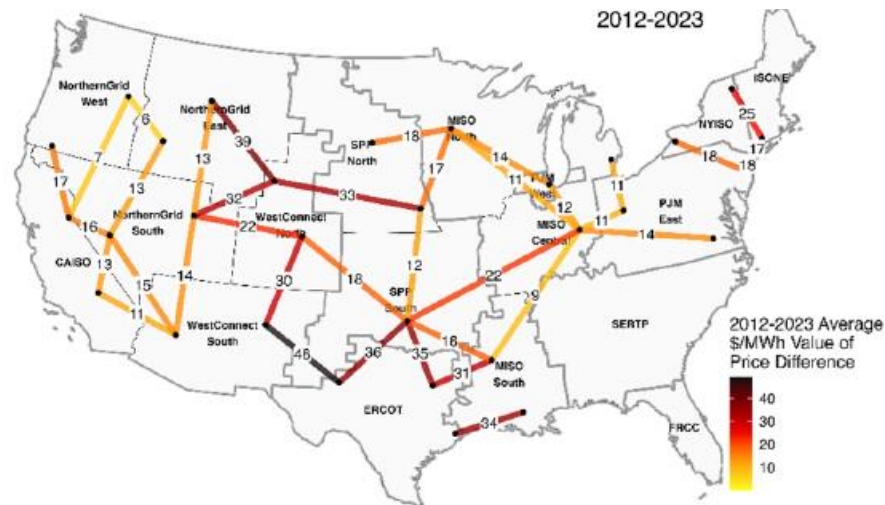
Below is the map generated from this new tool, including regional and interregional lines, using data from 2021 through 2025. This map shows the highest average value as being \$57.3/MWh for the ERCOT West – SPP South Hub line, as compared to the highest average of \$48/MWh in the older study cited by DOE. **This map should be inserted in place of (or in addition to) the earlier maps on page 40.**



For comparison, on the following page is the map presented in the Draft Needs Study from the earlier LBNL study.¹⁸ The above average 2021 - 2025 transmission values are all generally the same or greater than those shown in this earlier analysis.

¹⁷ *Energy Market Value Tool: Stage 1 – Transmission Value*, <https://emp.lbl.gov/energy-market-value-tool-stage-1-transmission-value>. Accessed on August 25, 2026.

¹⁸ Draft Needs Study at 40.



In addition to using the updated map of the 2021-2025 transmission values, the language on pages 38-39 should be revised to reflect these updated data as follows (inclusive of an updated citation and Figure reference):

Locational marginal price (LMP) is defined as the marginal cost of supplying the next increment of energy demand at a particular location, considering factors like generation costs, demand, and transmission constraints. Differences in the LMP of electricity at different wholesale market pricing nodes can highlight existing transmission congestion in the system. Differences in LMPs indicate that the system's transmission constraints limit the ability to deliver lower priced generation from one node to customers at the higher price node. Adding transmission reinforcements on a path between the two nodes to alleviate transmission constraints would provide some congestion relief value by lowering the average LMP across the two nodes. Lawrence Berkeley National Laboratory (LBNL) analyzed differences in real-time LMPs between 65 pairs of pricing nodes across the Need Study regions within the contiguous U.S. from 2012 to 2023 to approximate the value of connecting the two nodes with new or reinforced transmission infrastructure (LBNL, 2026 2025b) and has since updated the data through 2025. Figure V-2 shows the 65 hypothetical transmission links using LBNL's data for 2021-2025, which include 28 links within a region, 30 links between Needs Study regions within the same interconnection, and seven links between interconnections.

According to LBNL’s analysis, transmission links crossing electricity market seams between regions or interconnections show the highest potential for transmission congestion value, as indicated by the differences in LMP which can be seen in Figure V-2 (e). For example, cross-interconnection links from ERCOT to neighboring regions show some of the highest LMP differentials from \$3141/MWh to \$4857/MWh averaged across all hours from 2012 to 20232021 to 2025, and links between Western Interconnection (WestConnect) and Eastern Interconnection (SPP) have LMP differentials from \$1824/MWh to \$3331/MWh averaged across all hours from 2012 to 20232021 to 2025 (Figure V-2 (a)). Links between regions within an interconnect also have transmission congestion value, particularly between NorthernGrid and WestConnect and between, ISO-NE and NYISO, and SPP and MISO. Transmission links within regions have lower LMP differentials, with the highest-value within-region links between New York City and the rest of NYISO (\$17–\$18/MWh) and within MISO NorthernGrid South (\$15/MWh) (Figure V-2(b)).

A valuable resource that is greatly underutilized in the Draft Needs Study is the North American Electric Reliability Corporation (NERC) Interregional Transfer Capability Study (ITCS), submitted to the Federal Energy Regulatory Commission (FERC) in November 2024, in compliance with the Fiscal Responsibility Act of 2023. While Footnote 41 of the Draft Needs Study states that Chapter VII “discusses NERC’s Interregional Transfer Capability Study,” there is no such discussion or presentation of the quantitative results of the ITCS. These findings should be explicitly provided in Chapter VII, such as in the following manner on page 82 (footnotes omitted):¹⁹

Recent long-term transmission studies conducted outside of regional planning processes include analyses guided by capacity expansion modeling and analyses of interregional transfer capacity to support reliability and resource adequacy needs. NERC’s Interregional Transfer Capability Study recommends 35 GW of additional transfer capability to improve resource adequacy under extreme conditions. Moreover, NERC conducted an additional sensitivity analysis that increased the minimum margin level

¹⁹ North American Electric Reliability Corporation, Interregional Transfer Capability Study, Final Report (Nov. 2024), https://www.nerc.com/globalassets/initiatives/itcs/itcs_final_report.pdf

from 3 to 6%, raising the recommended prudent additions from 35 to 58 GW. The table below shows the specific interregional transfer capability recommendations from NERC.

Table 7.7: Recommended Prudent Additions Detail

Transmission Planning Region	Weather Years (WY) / Events	Resource Deficiency Hours	Maximum Deficiency (MW)	Additional Transfer Capability (MW)	Interface Additions (MW)
ERCOT*	Winter Storm Uri (WY2021) and nine other events	135	18,926	14,100	Front Range*** (5,700) MISO-S*** (4,300) SPP-S** (4,100)
MISO-E	WY2020 Heat Wave and two other events	58	5,715	3,000	MISO-W** (2,000) PJM-W (1,000)
New York	WY2023 Heat Wave and seven other events	52	3,729	3,700	PJM-E (1,800) Québec** (1,900)
SPP-S	Winter Storm Uri (WY2021)	34	4,137	3,700	Front Range** (1,200) ERCOT** (800) MISO-W (1,700)
PJM-S	Winter Storm Elliott (WY2022)	20	4,147	2,800	PJM-E (2,800)
California North*	WY2022 Heat Wave	17	3,211	1,100	Wasatch Front (1,100)
SERC-E	Winter Storm Elliott (WY2022)	9	5,849	4,100	SERC-C (300) SERC-SE (2,200) PJM-W (1,600)
SERC-Florida	Summer WY2009 and Winter WY2010	6	1,152	1,200	SERC-SE (1,200)
New England	WY2012 Heat Wave and two other events	5	984	700	Québec** (400) Maritimes (300)
MISO-S	WY2009 and WY2011 summer events	4	629	600	ERCOT*** (300) SERC-SE (300)
TOTAL				35,000	

Increasing Energy Deficiency Hours

* Transfer capability additions did not fully address identified resource deficiencies

C. Historical Transmission Data

In section *IV. Historical Transmission Investment*, the Draft Needs Study notes that “from 2016 to 2024, *significant investments* have been made to enhance the reliability, capacity, and resilience of the transmission system,”²⁰ and that “85,000 circuit-miles of newly constructed, upgraded, or rebuilt transmission lines rated at or above 69 kV have been built.”²¹ In a footnote, DOE explains that this is equal to 16% of total existing circuit-miles based on an estimated 526,028 circuit-miles. Such an increase amounts to less than two percent of the current system

²⁰ Draft Needs Study at 26.

²¹ *Ibid.*

having been added each year on average. DOE also explains that the amount of new transmission added declined in 2024.²² Moreover, only 4% of new circuit-miles have been at 500 kV or above, and the amount of transmission added varies by region, with much lower amounts constructed in PJM than in ERCOT, for example.²³

These data about transmission expansion stand in contrast to the final 2023 National Transmission Needs Study finding that “transmission investments steadily increased for the United States as a whole during the first half of the decade, followed by several years of decreased energization” and that “the rate of annual installs between 2016 and 2020 actually decreased to a negative 79 circuit-miles per year.”²⁴ It appears that the 2023 study provided the net amount of added transmission accounting for retired infrastructure, which more clearly reveals the transmission expansion patterns.

As a result, there is no basis to conclude that these additions were significant. The purpose of this Needs Study is to determine where there are the greatest gaps in transmission rather than characterize past levels of expansion. ACORE recommends that the final study remove the reference to “significant” transmission growth as follows on current page 26:

- From 2016 to 2024, ~~significant investments have been made to enhance the reliability, capacity, and resilience of the transmission system.~~ Throughout all regions in the U.S., 85,000 circuit-miles of newly constructed, upgraded, or rebuilt transmission lines rated at or above 69 kV have been built.³³

In addition, transmission construction for 2025 is not included even though such data is readily available, such as in the FERC 2025 State of the Market Report,²⁵ although there appear to be discrepancies between the FERC and DOE data which should be reconciled.²⁶ DOE should

²² *Ibid.* at 30.

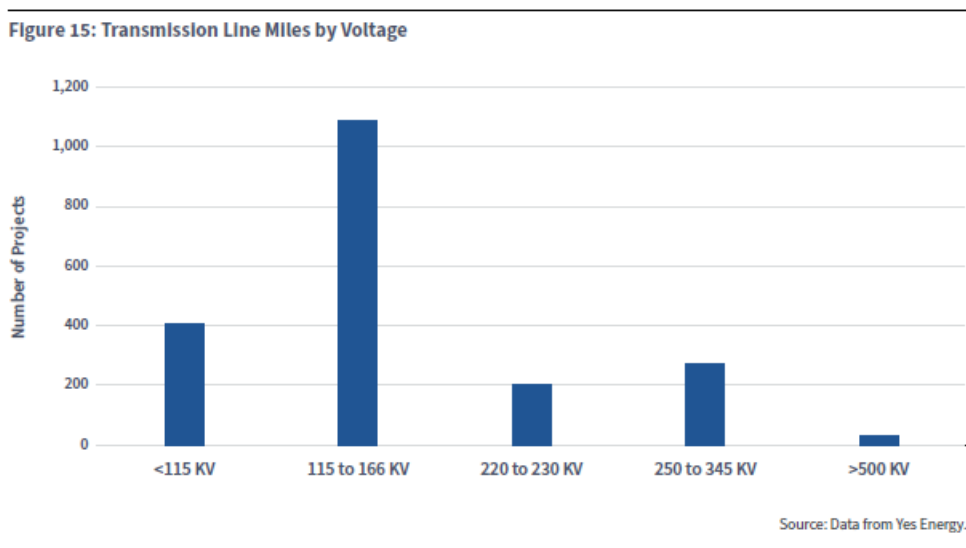
²³ *Ibid.* at 26.

²⁴ US Department of Energy, *National Transmission Needs Study* (Oct. 2023) at 21, https://www.energy.gov/sites/default/files/2023-12/National%20Transmission%20Needs%20Study%20-%20Final_2023.12.1.pdf.

²⁵ Federal Energy Regulatory Commission, *2025 State of the Markets, Staff Report* (March 2026), <https://cms.ferc.gov/news-events/news/report-3-state-markets-report-2025>

²⁶ See for example, Federal Energy Regulatory Commission, *2024 State of the Markets, Staff Report* (March 2025) at 32: “In 2024, over 5,000 circuit miles of transmission projects entered service,”

also provide a breakdown of the voltage on an annual basis. For example, the chart below from FERC’s State of the Market Report shows very low levels of high voltage lines constructed in 2025.²⁷



D. Transmission Benefits

In section *VI. Future Needs Assessment through Review of Regional Planning Reports*, DOE provides high level summaries of the planning regions’ transmission studies. In addition to these studies generally being out of date by at least a year, a notable omission is that only the costs are reported, without data on the benefit-cost ratios or net benefits. For example, the following findings were omitted for the Midcontinent Independent System Operator (MISO) and Southwest Power Pool (SPP).

- MISO’s Long Range Transmission Planning (LRTP) Tranche 2.1 provides benefits of \$1.80 to \$3.50 for every dollar spent, amounting to \$23 billion in benefits to customers over the next 20 years.²⁸

<https://www.ferc.gov/media/state-markets-report-2024>, compared to the Draft Needs Study at 30: “In 2024, the number of circuit-miles installed dropped to approximately 3,600 circuit-miles.”

²⁷ Federal Energy Regulatory Commission, *2025 State of the Markets, Staff Report* at 21.

²⁸ Midcontinent ISO, *LRTP Tranche 2.1 Benefits Analysis Results Review*, (September 25, 2024), <https://cdn.misoenergy.org/20240925%20LRTP%20Workshop%20Item%2001%20Tranche%202.1%20Business%20Case%20Overview649810.pdf>.

- *SPP's 2025 Integrated Transmission Plan* identifies new and upgraded high voltage lines that demonstrate the highest benefit-to-cost ratios in SPP's transmission planning history, ranging from \$12 to \$18 for every dollar spent.²⁹

These and other net benefits or benefit/cost ratio calculations from the planning regions should be included in the final study as they provide important quantitative data on the value of transmission. The table below from Grid Strategies, LLC³⁰ includes the benefit-cost data for a range of transmission lines along with the implied costs to consumers from each year of delay. **At a minimum a table showing the transmission portfolios and the benefit-cost ratios should be added to the final Needs Study, inclusive of SPP's 2025 ITP.**

TABLE 1 | Summary of regional transmission portfolios evaluated and estimated cost of delay

Region	Portfolio	Total Benefits	Upfront Cost	Benefit-Cost Ratio	Estimated consumer cost from 1-year delay
MISO	MVP	\$12 billion	\$6.5 billion	1.8	\$1.4 billion
MISO	LRTP Tranche 1	\$27 billion	\$10.3 billion	2.6	\$1.8 billion
MISO	LRTP Tranche 2.1	\$44 billion	\$21.9 billion	1.8	\$1.5 billion
ERCOT	CREZ	\$84 billion	\$6.9 billion	12.2	\$6.3 billion
SPP	RCAR III	\$42 billion	\$7.3 billion	5.76	\$2.9 billion
SPP	2023 ITP	\$2.6 billion	\$1.1 billion	2.29	\$0.123 billion
SPP	2024 ITP	\$88.7 billion	\$7.7 billion	8.23	\$7.7 billion
NYISO	AC PPTN	\$1.7 billion	\$1.1 billion	1.5	\$0.132 billion

E. Resource Adequacy Value of Transmission

ACORE strongly supports the inclusion of section V.c. *Resource Adequacy and Resilience Benefits of Transmission* and specifically, DOE's finding that:

Transmission plays a critical role in maintaining resource adequacy by enabling generation to move to where it is needed each hour, which is important both within

²⁹ Derek Wingfield, "SPP board advances regional transmission plan to keep pace with accelerating growth and ensure grid reliability," *Southwest Power Pool*, November 4, 2025, <https://spp.org/news-list/spp-board-advances-regional-transmission-plan-to-keep-pace-with-accelerating-growth-and-ensure-grid-reliability>.

³⁰ Zach Zimmerman, Rob Gramlich and Michael Goggin, Grid Strategies LLC, Delaying transmission increases costs and reduces benefits for consumers (Nov. 2025) at 9, https://gridstrategiesllc.com/wp-content/uploads/GS_WIRES-Cost-of-Delayed-Transmission.pdf

regions, where generation resources may not be located near major load centers, and between regions that manage varying load profiles and resource mixes.³¹

Balancing the variation among generation resource availability and load profiles is one key to the resource adequacy value of transmission and especially interregional transmission. In the context of resource adequacy, DOE also references its *2025 Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid* (“Resource Adequacy Report”), which DOE notes “identified resource adequacy as a growing concern for the electric grid.”³² Right after citing this report, DOE reiterates that: “Transmission supports resource adequacy by ensuring that power generated by these resources can be delivered to load when needed by enabling the sharing of energy resources across regions with different load profiles, weather patterns, and generation mixes.”³³

As ACORE and others pointed out, the Resource Adequacy Report used a flawed methodology by focusing entirely on projections of generation retirements and additions, which were respectively overstated and understated, and did not account for the important role of transmission in providing resource adequacy.³⁴ Because the Resource Adequacy Report omits a substantive finding of the Draft Needs Study, **DOE should remove the citation to the flawed Resource Adequacy Report.** In addition, the findings of the final Needs Study should be incorporated into any future resource adequacy assessments to ensure that the role of transmission is accurately incorporated.

ACORE also recommends that in the Needs Study DOE incorporate the recommendations of recent reports on how to better quantify the resource adequacy benefits of transmission, such as by accounting for the resource adequacy value of non-firm imports; and the value of high-voltage direct current (HVDC) transmission in providing resource adequacy and ancillary services to the grid. At a minimum, these include:

³¹ Draft Needs Study at 54.

³² *Ibid.* at 82.

³³ *Ibid.* at 82.

³⁴ *Request for Rehearing of the Clean Energy Organizations* (Aug. 2025) at 51-52, <https://acore.org/resources/request-for-rehearing-of-doe-resource-adequacy-protocol/>

- The Brattle Group and DNV, *The Operational and Market Benefits of HVDC To System Operators* (September 2023), <https://acore.org/resources/the-operational-and-market-benefits-of-hvdc-to-system-operators/>
- Grid Strategies LLC, *Resource Adequacy Value of Interregional Transmission*, (June 2025), https://gridstrategiesllc.com/wp-content/uploads/GridStrategies_RAValueInterregionalTx_250601.pdf

F. Advanced Transmission Technologies

To minimize the costs of addressing transmission needs, the final Needs Study should expand the information provided on advanced transmission technologies, which include Grid Enhancing Technologies (GETs) and High-Performance Conductors (HPCs), along with a finding that advanced transmission technologies must be evaluated in transmission planning on an equal basis with new transmission builds.

The Draft Needs Study correctly recognizes the range of benefits that GETs provide but should also include HPCs, which encompass both advanced conductors³⁵ and superconductors, as follows in the statement on page 2:

Addressing transmission needs by upgrading, uprating, or building new transmission facilities—including grid-enhancing technologies (GETs) and **High-Performance Conductors (HPCs), including advanced conductors and superconductors**—can improve the reliability and resilience of the power system, alleviate transmission congestion and unscheduled flows, alleviate power transfer capacity limits between neighboring regions, deliver cost-effective generation to meet demand, and/or meet projected future generation, electricity demand, or reliability requirements.

DOE later describes advanced conductors as being a subset of GETs,³⁶ which is not correct as GETs are generally software and other devices that enhance the capacity of transmission while advanced conductors involve certain transmission hardware. ACORE therefore recommends the following edit on page 8:

³⁵ For example, DOE can adopt the Order No. 1920 definition in footnote 2553: “Advanced conductors include present and future transmission line technologies whose power flow capacities exceed the power flow capacities of conventional aluminum conductor steel reinforced conductors.”

³⁶ Draft Needs Study at 8, stating: “GETs, such as advanced conductors...”

Both traditional transmission infrastructure and **advanced transmission technologies, including GETs and HPCs**, can be employed to improve the efficiency of the grid, improve power quality, or enable power delivery at lower costs.

DOE's findings can be greater bolstered by incorporating statements from FERC and NERC on advanced transmission technologies. At a minimum, revisions to the language on ATTs from page 8 are as follows:

Transmission infrastructure is required to connect generation resources to the larger system so that energy can be delivered to load. As more generation is developed and load continues to increase, the transmission grid will reach its limit in many places. The capacity of the grid must be expanded through the new infrastructure, rebuilds, ~~or the~~ **installation of GETs and HPCs. FERC's Order No. 1920 specifically requires the full evaluation of these technologies in the determination of transmission facilities to meet transmission needs.**³⁷ The NERC ITCS recommends greater use of advanced conductors, Dynamic Line Ratings and power flow control devices for increasing transfer capability, which as NERC points out "are typically less expensive and require less lead time than building a new transmission line."³⁸

Additional resources on ATTs and their benefits that would bolster the Final Needs Study include the following:

- AMP Coalition and Grid Strategies LLC, *Unlocking the Grid: A Playbook on High-Performance Conductors for State and Regional Regulators and Policymakers* (Oct. 2024), <https://acore.org/resources/unlocking-the-grid-a-playbook-on-high-performance-conductors-for-state-and-regional-regulators-and-policymakers/>
- WATT Coalition and Grid Strategies LLC, *Unlocking Power: A Playbook on Grid Enhancing Technologies for State and Regional Regulators and Policymakers* (Oct. 2024), <https://acore.org/resources/unlocking-power-a-playbook-on-grid-enhancing-technologies-for-state-and-regional-regulators-and-policymakers/>
- Bill White, *Untapped Energy Efficiency Benefits of High-Performance Conductors* (Aug. 2026), <https://acore.org/wp-content/uploads/2026/08/Untapped-Energy-Efficiency-Benefits-of-High-Performance-Conductors-Update.pdf>

³⁷*Building for the Future Through Electric Regional Transmission Planning and Cost Allocation*, Order No. 1920, 187 FERC ¶ 61,068 (May 2024) at P 1163 – 1247.

³⁸ NERC ITCS at 134.

- Bruce Tsuchida, Linqun Bai, and S. Ziyi Tang of the Brattle Group and Jay Caspary of Grid Strategies, LLC, *Incorporating GETs and HPCs into Transmission Planning Under FERC Order No. 1920* (April 2025), https://acore.org/wp-content/uploads/2025/04/Report_Incorporating-GETs-and-HPCs-Under-FERC-Order-1920_April-21-2025.pdf

G. Southeast Congestion Value Analysis

The Draft Needs Study incorporates the findings of two national laboratory studies that estimate the congestion value of transmission in the Southeast, a non-RTO/ISO region that does not use Locational Marginal Prices from which to derive a measure of marginal congestion. ACORE supports the conduct of studies such as these to ensure transmission congestion costs, which negatively impact ratepayers, are evaluated for all regions, and not just those within RTO/ISO footprints. These two studies provide useful information for the planning processes in the Southeast and Florida regions.

III. Conclusion

ACORE appreciates the issuance of this Draft Needs Study and respectfully asks that DOE include in the Final Needs Study, at a minimum: a quantitative assessment of regional and interregional transmission needs under multiple scenarios; the inclusion of up-to-date resources; and an expanded discussion of the value of advanced transmission technologies in meeting transmission needs.

Respectfully submitted,

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September 8, 2026