Interregional Renewable Energy Zones

David J. Hurlbut,[1] Jianyu Gu,[1] Srihari Sundar,[1] An Pham,[1] Barbara O'Neill,[1] Heather Buchanan,[1] Donna Heimiller,[1] Mark Weimar,[2] and Kyle Wilson[2]

1 National Renewable Energy Laboratory
2 Pacific Northwest National Laboratory

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Technical Report
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National Renewable Energy Laboratory
15013 Denver West Parkway
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303-275-3000 • www.nrel.gov

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Preface

This report is part of the U.S. Department of Energy's (DOE's) National Transmission Planning Study (NTP Study), conducted by the National Renewable Energy Laboratory and Pacific Northwest National Laboratory. The aim of the NTP Study is to identify transmission that will provide broad-scale benefits to electric customers; inform regional and interregional transmission planning processes; and identify interregional and national strategies to accelerate decarbonization while maintaining system reliability. Additional information on the NTP Study is at https://www.energy.gov/gdo/national-transmission-planning-study. Work for this report was funded by DOE's Grid Deployment Office.

The purpose of this interregional renewable energy zone (IREZ) study is twofold. First, it provides a bridge between the technical modeling used in the NTP Study's national transmission scenarios and ground-level regulatory and financial decision making. Where it is congruent with national results, an IREZ corridor is an example of one means to achieving a portion of the benefits identified in the national analysis.

Second, this study is a preliminary analysis to help state decision makers determine whether to pursue more detailed analyses of IREZ corridors that are relevant to them. This report could not fully account for all the case-specific details that would affect the configuration of a transmission project. Nevertheless, if a corridor examined in this study has a high benefit-to-cost ratio based only on energy cost savings, a follow-on study focusing on that corridor might expand the economic analysis to include local factors that we were not able to address here. A guiding premise behind the IREZ analysis is that states will ultimately take the lead in deciding whether to pursue IREZ development.

The forthcoming report *Regulatory Pathways to Interregional Transmission: A Landscape Assessment* is a companion to this IREZ report under the NTP Study umbrella (Homer et al. forthcoming). That report explains the regulatory challenges to interregional transmission that have historically prevented realizing many of the benefits quantified in the NTP Study technical scenarios. In many ways, the *Regulatory Pathways* report provides the institutional background for why this IREZ report focuses on state decision makers as its primary audience. The IREZ report, the *Regulatory Pathways* report, and other volumes in the NTP Study series provide a knowledge base that states can use to achieve some of the benefits revealed in the NTP Study's national scenarios.

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List of Acronyms

ARR	annual revenue requirement
BPA	Bonneville Power Administration
CREZ	Competitive Renewable Energy Zone
DCRF	depreciated capital recovery factor
DOE	U.S. Department of Energy
EIA	Energy Information Administration
ERCOT	Electric Reliability Council of Texas
EUE	expected unserved energy
FERC	Federal Energy Regulatory Commission
GW	gigawatts
HVAC	high-voltage alternating current
HVDC	high-voltage direct current
IGBT	insulated gate bipolar transistor
IREZ	interregional renewable energy zone
ISO-NE	Independent System Operator of New England
kV	kilovolt
LCC	line-commutated converter
LCOE	levelized cost of energy
LMP	locational marginal price
MISO	Midcontinent Independent System Operator
MOSFET	metal oxide semiconductor field effect transistor
MW	megawatt
MWh	megawatt-hour
NOPR	notice of proposed rulemaking
NREL	National Renewable Energy Laboratory
NTP Study	National Transmission Planning Study
NYISO	New York Independent System Operator
PJM	PJM Interconnection
ROW	right-of-way
SPP	Southwest Power Pool
VSC	voltage-sourced converter
WECC	Western Electricity Coordinating Council
WEIM	Western Energy Imbalance Market

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Acknowledgments

The authors of this report are grateful for support from the Department of Energy's Grid Deployment Office (GDO) and Office of Energy Efficiency and Renewable Energy (EERE), particularly Hamody Hindi, Kelly Kozdras, Melissa Birchard, Adria Brooks and Carl Mas (GDO) and Paul Spitsen and Alejandro Moreno (EERE). We are also grateful to Michelle Manary (GDO), Ben Kroposki (NREL), and Carl Imhoff (PNNL) for their leadership and vision at the inception of the NTP Study, which included a specific task for studying interregional renewable energy zones.

Visualization of the IREZ results would not have been possible without the outstanding maps created by Billy Roberts (NREL). We are also grateful for the excellent production and editorial support of NREL's communications department, especially Emily Horvath, Madeline Geocaris, and Nicole Leon. Liz Craig designed the one-page IREZ summaries.

We are also grateful for review comments provided by Sarah Fitzpatrick and Elliott Nethercutt of the National Association of Regulatory Utility Commissioners; Juliet Homer of Pacific Northwest National Laboratory; Mark Ruth, Jeff Cook, Dan Bilello, Jaquelin Cochran, and Faith Smith of NREL; and Yamit Lavi, Melissa Birchard, Adria Brooks and Kelly Kozdras of GDO.

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Executive Summary

A growing number of studies suggest that fundamental changes in the nation's power sector have major implications for transmission planning (FERC 2022). The changing landscape suggests, among other things, the need for a concerted reexamination of long-distance interregional transmission solutions. Large, long-distance interregional transmission projects have faced institutional obstacles in the past, however (Homer et al. forthcoming). The purpose of this study is to design and test an approach to interregional transmission that can respond both to the evolving needs of the U.S. power system and to the regulatory questions that states and other authorities must consider when approving new investments in transmission.

This study develops a model using renewable energy zones to address the new challenges of interregional transmission planning. An **interregional renewable energy zone (IREZ)** is an area comprising a very high concentration of very low-cost developable renewable energy potential. An **IREZ hub** is a collection point on the bulk power system to which renewable energy plants built in the IREZ can connect easily. The hub anchors an **IREZ corridor** that consists of a dedicated high-voltage transmission path from the IREZ hub to a major load center.

The renewable energy zone model began in Texas two decades ago, supporting that state's expansion of wind power and (more recently) solar power. Lessons from the Texas experience informed development of the IREZ model used in this study.

We have framed this analysis using the following assumptions:

- States would lead the decision whether to develop an IREZ corridor, and transmission planning entities would respond to state guidance.
- States affected by the same IREZ corridor could collaborate on selecting the most cost-effective transmission option and on setting principles for cost allocation and landowner compensation.
- Development of each IREZ corridor would be independent of other IREZ corridors, apart from collaborations among states to identify joint plans that are mutually beneficial.
- States who reach an understanding on developing an IREZ corridor would lead outreach to federal authorities on analytical support, regulatory approval, and financial assistance.

We have identified and quantified several high-value IREZ corridors that affected states might consider for interregional transmission planning. Our analysis suggests that these corridors can be valuable tools for reducing carbon emissions in a manner that uses known technologies, has relatively small net impact on customers' electricity bills, improves resource adequacy, and provides the grid with an additional measure of resilience against major disruptions related to climate change and other causes.

IREZ Fundamentals

The amount of renewable capacity that a load center can get from an IREZ is a function of the connecting transmission. For analytical consistency, we assume a standard transmission configuration: a 600-kV high-voltage direct current (HVDC) line with a total transfer capability

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of 3 gigawatts (GW). Rather than adjusting the volume of the IREZ corridor to an optimal capacity, we examine the role that 3 GW of IREZ resources might play in a load center's resource mix. This approach is in line with how transmission is actually planned and built. In other words, IREZ renewables would constitute one part of the destination load center's resource mix, combined with locally sourced renewables (including offshore wind where available), conventional generation, and other resources.

We anticipate, however, that subsequent analyses initiated by the affected states could identify alternative configurations that could be more cost-effective for the circumstances of a specific corridor. This study serves as a preliminary analysis of opportunities.

Competition among resource developers is an important part of the renewable energy zone model. We capture this analytically by assuming that developers who want to build renewable energy plants on the best 15 GW of resource potential in a zone will compete for access to a 3-GW transmission hub. The marginal cost of the best 15 GW is the economic metric we use to describe each IREZ. In other words, our analysis does not pick specific sites for project development. We assume instead that competition will decide which sites would be developed, and that the marginal cost of the zone's best 15 GW is a reasonable proxy cost for the renewable capacity that would ultimately be developed.

The Corridors

We used NREL's Renewable Energy Potential (reV) model to identify renewable energy zones and the least-cost path between a load center and an IREZ.[1] The model calculates renewable energy potential—nameplate capacity, annual generation potential, and average annual cost—based on the meteorological and geospatial attributes of each site. The reV model's transmission functionality accounts for different terrain and land uses between the two points, and it excludes from consideration land that cannot be used for transmission (Lopez 2024). However, *reV does not provide a recommended transmission route*. Its purpose in this IREZ analysis is to provide a better estimate of transmission line-miles, improving the economic analysis of the corridor.

The map in Figure ES-1 shows the corridors identified in this analysis. Corridors link each load center with its best-fit IREZ. "Best fit" is a function of the IREZ's levelized cost of energy (LCOE) and transmission distance; lower LCOE and shorter distances are better. For all wind IREZs, the marginal LCOE of the best 15 GW is between $19 and $21 per MWh. For all solar IREZs, the marginal LCOE of the best 15 GW is between $22.70 and $23.90 per MWh.

[1] For more on the reV model, see https://www.nrel.gov/gis/renewable-energy-potential.html.

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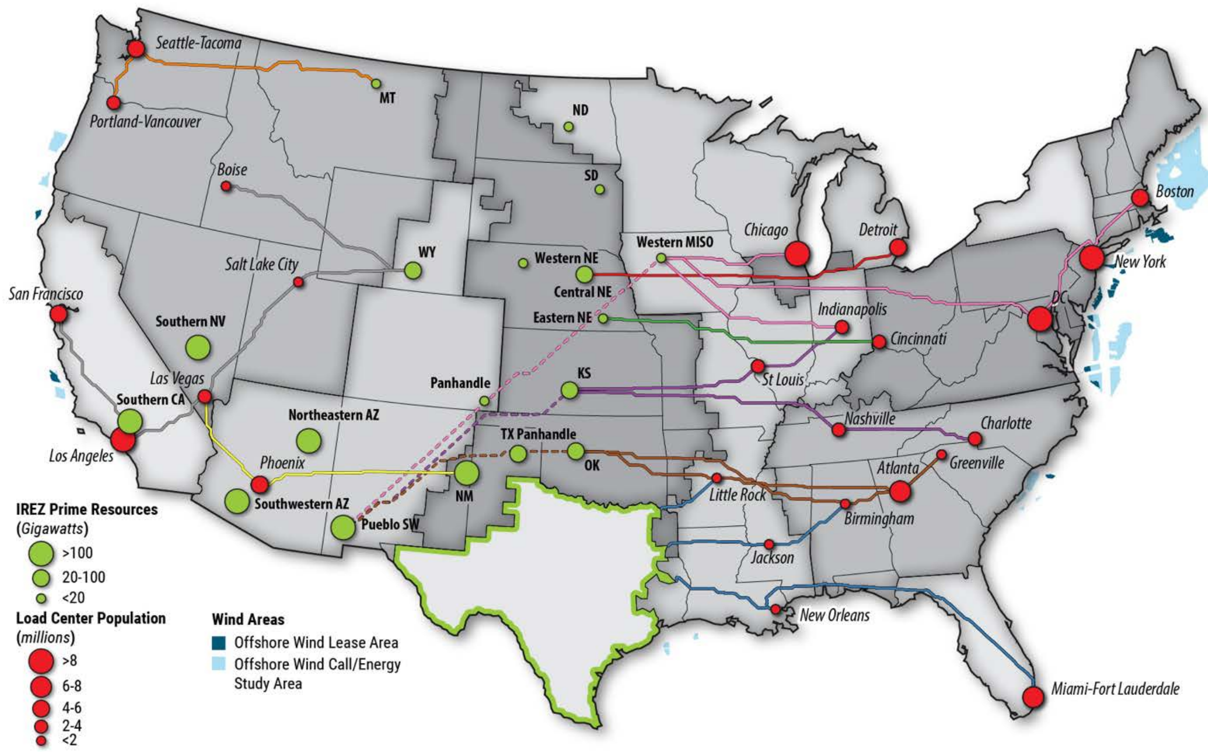

Note: Corridors shown on the map represent least-cost distances based on available data. They are not recommendations for specific transmission routes. Colors identify corridors from a unique IREZ; dashed lines indicate connections between a primarily wind IREZ and a solar IREZ in the Southwest. IREZs on this map shown with no connection to a load center may provide additional supply options. Shaded areas indicate transmission planning regions used in Phase 1 of the IREZ analysis. (Hurlbut et al. 2022). See Sections 1.7 and 2.2 for an explanation of why ERCOT is depicted as a region rather than a hub. Offshore wind areas are shown to illustrate where they and IREZ resources might both contribute to a load center's clean energy resource mix.

Figure ES-1. IREZ corridors

The initial matching optimization connected load centers to IREZs that were in the nation's wind belt. We further examined the benefit of connecting the wind IREZs in Oklahoma, Kansas, and Iowa with the Pueblo Southwest solar IREZ between Arizona and New Mexico. These three wind IREZs were the best fits for the largest number of large load centers in the Eastern Interconnection. The Pueblo Southwest IREZ had the largest amount of least-cost solar potential by a significant margin. (The largest load centers in the Western Interconnection had local access to solar zones in Southern California, Southern Nevada, and Arizona which would not require a long-distance HVDC line.)

For additional context and reference, the map also shows development areas for offshore wind. Analyses of IREZ corridors and offshore wind rely on different methodologies that are appropriate to the respective technologies, both of which represent high-volume delivery of clean energy resources. Including offshore wind in Figure ES-1 illustrates where both resources might benefit major load centers.

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Economic Analysis

The analysis applied two economic measures to each IREZ corridor. One is the net savings in the cost of generating energy for the target load center, which we measure by comparing the hourly output of energy from the IREZ (priced at the marginal LCOE) with the time-sensitive cost of local generation in the load center. We then test whether the annual savings in energy costs provides enough economic headroom to pay for the annual revenue requirement of the IREZ transmission line.

We take a "backcasting" approach to measuring net energy cost savings. That is, instead of forecasting where costs will be a decade from now, we measure what the cost savings would have been in 2022 had the IREZ corridor existed then. The preferred indicator was hourly locational marginal prices (LMPs), which we compared to the marginal LCOEs of IREZ resources. Load centers in markets operated by regional transmission organizations (RTOs) or independent system operators (ISOs) have LMP data. For load centers that were outside but close to an RTO or ISO, we used interchange LMPs, as explained in Section 5.2.[2]

We summarize energy cost savings as partial benefit/cost ratios. In all cases, the ratios indicated net energy cost savings greater than the annualized cost of IREZ transmission. These ratios are not predictors of future economics; rather, they are initial reference points grounded in actual costs observed for 2022, with future benefits depending on:

- How renewable energy capital costs change
- How DC transmission costs change
- How the load center's cost of generation changes, which in turn depends on future natural gas prices, plant retirements, and demand growth.

For example, NREL analysis of capital cost trajectories indicates the LCOE of solar could decline over the next 10 years by between 15% and 44% from costs observed for 2022, while onshore wind LCOEs could decline by between 14% and 32% (NREL 2023). We assume that any state-led effort to investigate an IREZ corridor further will include a process to determine a reasonable stakeholder consensus on cost trends that proceed from the reference points analyzed in this study.

To test resource adequacy, we measure changes in expected unserved energy (EUE). EUE analysis simulates the shortfalls that would occur under a large range of potential generator outages or other impacts to supply and demand. Specifically, we compare the EUE with additional renewable resources from the IREZ against EUE with the same amount of wind or solar built locally. We find that in most cases, IREZ renewables contribute more to resource adequacy than local renewables do. This suggests that as states increase their use of wind and

[2] Interchange LMPs capture the value—to the RTO/ISO—of energy imported from the neighboring area, but they might not capture the actual cost of producing energy in the exporting region. In two cases—Atlanta and Miami—interchange LMPs were not available. We instead used the utilities' fuel cost adjustment riders to estimate time-sensitive energy costs. These charges vary seasonally and by peak/off-peak time of day, but they lack the hourly precision of LMPs. Consequently, some of the time-specific value of IREZ resources could not be captured for these two destinations in this analysis. A follow-on analysis for any of these load centers should develop hourly approximations of the utility's cost of generating or procuring energy.

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solar generation, combining IREZ resources with local resources could reduce the cost of resource adequacy, compared to relying solely on local renewables.

External Alignment of IREZ Results

Several IREZ corridors identified in this analysis align with findings from DOE's October 2023 *National Transmission Needs Study* (DOE 2023) and the National Transmission Planning Study (DOE forthcoming). Many also align with transmission projects that are under construction or in advanced stages of permitting.

The *Needs Study* identified several between-region interfaces where future transmission capacity would provide national and local benefits. A number of IREZ corridors illustrate potential options for addressing some of those future needs in the Eastern Interconnection. Among the largest needs identified in that study were flows between the Plains, Midwest, and Mid-Atlantic regions (where corridors from the Iowa, Nebraska, and Kansas IREZs identified in this study might provide relief) and between the Plains, Delta, and Southeast regions (where corridors from the ERCOT, Kansas and Oklahoma IREZs might provide relief). Proposed projects in these regions that align with IREZ corridors include SOO Green, Grain Belt Express, and Southern Spirit.

In the Western Interconnection, corridors from the Wyoming IREZ coincide with the TransWest Express line (southern Wyoming to the Las Vegas area), PacifiCorp's Energy Gateway expansions (Wyoming to Salt Lake City and to Boise, with additional connection to Oregon and Washington), and the Cross-Tie line (linking Salt Lake City with eastern Nevada's ON Transmission line). The corridor from the New Mexico IREZ to Phoenix coincides with the SunZia project. Notably, both the Wyoming IREZ and the New Mexico IREZ match renewable energy zones identified in a 2009 study conducted for the Western Governors' Association (WGA 2009; Pletka 2009).

Implications for Tribes

Some renewable energy zones included tribal land, therefore development in these IREZs could affect several Indian tribes. These include various tribes of western Oklahoma, the Blackfeet and Flathead tribes in northwestern Montana, and the San Carlos and Tohono O'odham tribes in southeastern Arizona. We assume that tribal policies will determine whether tribal lands within these IREZs could be developed. Information about nearby IREZ corridors can inform tribal policies about land access, employment requirements, tribal revenues, and other project development issues.

IREZ Summaries

The following pages summarize each IREZ. States may use these summaries to determine whether a closer examination of options is warranted, what an IREZ's reasonable contribution might be to the state's resource mix, and which other states might have a stake in collaboration. Table 6 and Table 7 in the report show the numeric results for all IREZs together.

These summaries serve as a first glimpse of the prospects for IREZ corridors. The results reported here rely on standard capital cost inputs applied to all IREZ corridors, but case-specific

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inputs would replace these assumptions in any follow-on analysis conducted by or for the affected states. The benefit/cost ratios reported here indicate the economic headroom for accommodating local factors not addressed in this analysis but which could be addressed in a follow-on study.

We structured this analysis to help answer a threshold question for groups of states affected by an IREZ corridor:

> *Could the cost of a long-distance interregional transmission corridor be just and reasonable relative to its expected benefits?*

The definitive answer would come at the end of state collaboration and regulatory proceedings that would formally account for all uncertainties. The aim here is to provide an initial knowledge base that can spark subsequent investigation by states and stakeholders.

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Iowa IREZ

Marginal levelized cost of energy using the zone's best 15 GW: $20.12/MWh

Destinations

- Washington to New York to Boston
- Chicago/Milwaukee
- Indianapolis

Transmission congestion in PJM between Maryland and Pennsylvania frequently pushes wholesale power prices higher in Washington, DC and eastern Virginia. This could enhance the value of IREZ renewables delivered to the Washington, DC area. Alternative transmission configurations could reduce the cost of a shared corridor to Virginia/Maryland, NYISO, and ISO-NE. An IREZ corridor also appears to be cost effective for the Chicago/Milwaukee area and Indianapolis. Transmission links with IREZs in South Dakota or Nebraska could augment the supply of low-cost renewables if demand on these corridors is high.

	Destination				
	Washington, DC	**New York**	**Boston**	**Chicago/ Milwaukee**	**Indianapolis**
Energy cost savings[a] ($millions)	$740 *$994 with solar[d]*	$858	$886	$531	$557
Annual revenue requirement for transmission[b] ($millions)	$296 *$521 with solar[d]*	$323	$344	$186	$215
Benefit/cost ratio (energy savings only)	2.50 *1.91 with solar[d]*	2.66	2.58	2.85	2.59
Expected unserved energy (IREZ vs. local renewables)[c]	Worse *Better with solar[d]*	Similar	Similar	Worse	Worse
3 GW as % of 2022 peak (included load zones)	9% (PJM: PEPCO, BGE, Dominion)	9% (all NYISO)	12% (all ISO-NE)	11% (PJM: ComEd; MISO: WE)	18% (MISO: LRZ 6)

[a] Based on actual local energy costs in 2022. Energy costs will almost certainly be different when an IREZ corridor is built and energized. Decision makers and stakeholders should consider how their own expectations for future energy costs in their areas might affect benefit/cost ratios going forward. See Section 5.2 for an explanation of the methodology used.

[b] Based on a 600-kV HVDC transmission line from the IREZ to the load center. Decision makers and stakeholders should regard this as a benchmark for considering other transmission options that might be more cost-effective. See Section 5.1 for a description of assumed transmission costs.

[c] Impact on expected unserved energy (EUE) estimated by increasing simulated load to the point where EUE is approximately 0.001% of load, then adding 3 GW of new renewable resources and remeasuring EUE. See Section 5.3 for an explanation of the resource adequacy methodology and scoring criteria.

[d] *Italics* show results for scenarios that include an HVDC connection from the Pueblo Southwest IREZ to the Iowa IREZ.

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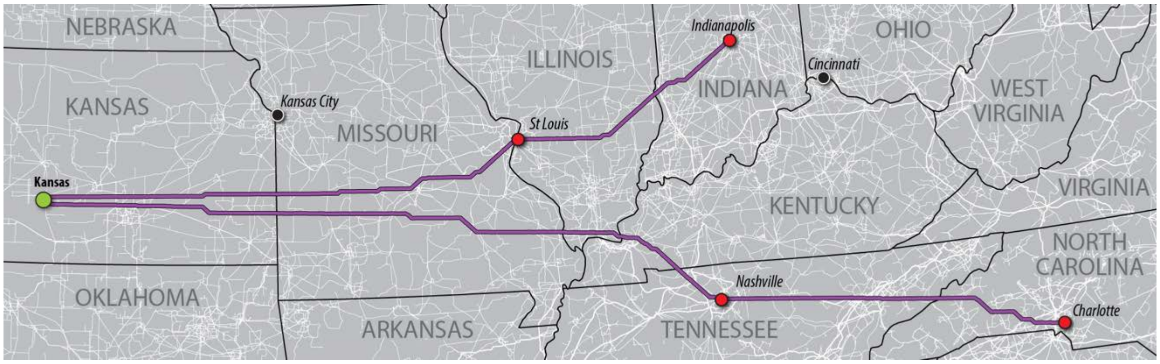
Kansas IREZ

Marginal levelized cost of energy using the zone's best 15 GW: $19.50/MWh



Destinations

- Nashville and Charlotte
- St. Louis and Indianapolis

Kansas has an abundance of wind development areas with very low LCOE. The path from Kansas to St. Louis to Indianapolis largely matches the path of the proposed Grain Belt Express. Partnership on a shared corridor from Kansas to TVA to Charlotte could test transmission configurations different from (and potentially superior to) the one used in this analysis.

	Destination			
	Nashville	Charlotte	St. Louis	Indianapolis
Energy cost savings[a] ($millions)	$610	$626 *$849 with solar*[d]	$603	$595
Annual revenue requirement for transmission[b] ($millions)	$248	$291 *$456 with solar*[d]	$212	$215
Benefit/cost ratio (energy savings only)	2.46	2.15 *1.86 with solar*[d]	2.85	2.77
Expected unserved energy (IREZ vs. local renewables)[c]	Better	Much better *Better with solar*[d]	Better	Better
3 GW as % of 2022 peak (included load zones)	9% (all TVA)	14% (all Duke Carolinas)	18% (Ameren MO and IL)	18% (MISO: LRZ 6)

[a] Based on actual local energy costs in 2022. Energy costs will almost certainly be different when an IREZ corridor is built and energized. Decision makers and stakeholders should consider how their own expectations for future energy costs in their areas might affect benefit/cost ratios going forward. See Section 5.2 for an explanation of the methodology used.

[b] Based on a 600-kV HVDC transmission line from the IREZ to the load center. Decision makers and stakeholders should regard this as a benchmark for considering other transmission options that might be more cost-effective. See Section 5.1 for a description of assumed transmission costs.

[c] Impact on expected unserved energy (EUE) estimated by increasing simulated load to the point where EUE is approximately 0.001% of load, then adding 3 GW of new renewable resources and remeasuring EUE. See Section 5.3 for an explanation of the resource adequacy methodology and scoring criteria.

[d] *Italics* show results for scenarios that include an HVDC connection from the Pueblo Southwest IREZ to the Kansas IREZ.

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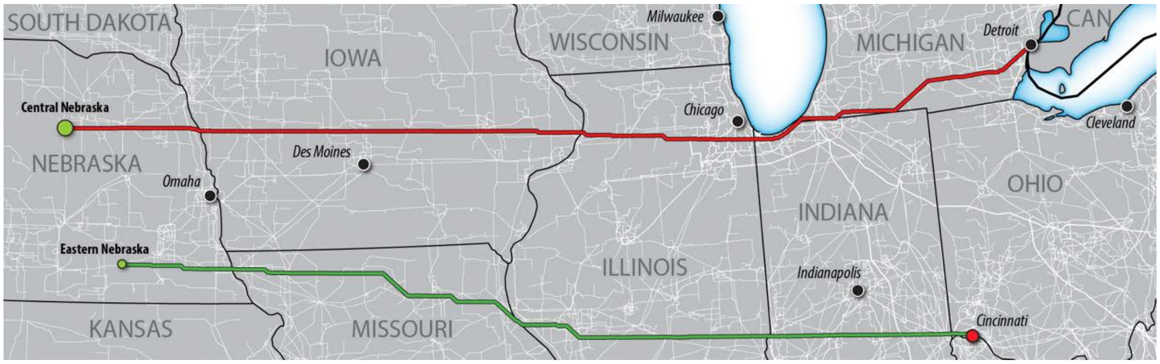
Nebraska IREZs

Marginal levelized cost of energy using the zone's best 15 GW: $19.70/MWh



Destinations

- Detroit
- Cincinnati

Benefits from reduced energy costs of IREZ resources benchmarked to 2022 are more than double the estimated cost of a DC line from the IREZ. Future reductions in the LCOE of IREZ renewables could provide more economic headroom. Future plant retirements near Detroit and Cincinnati could affect future generation costs, in turn affecting the future value of IREZ renewables.

	Destination	
	Detroit	Cincinnati
Energy cost savings[a] ($millions)	$650	$692
Annual revenue requirement for transmission[b] ($millions)	$264	$244
Benefit/cost ratio (energy savings only)	2.46	2.84
Expected unserved energy (IREZ vs. local renewables)[c]	Similar	Better
3 GW as % of 2022 peak (included load zones)	26% (DTE)	35% (Duke OH and KY; Dayton P&L)

[a] Based on actual local energy costs in 2022. Energy costs will almost certainly be different when an IREZ corridor is built and energized. Decision makers and stakeholders should consider how their own expectations for future energy costs in their areas might affect benefit/cost ratios going forward. See Section 5.2 for an explanation of the methodology used.

[b] Based on a 600-kV HVDC transmission line from the IREZ to the load center. Decision makers and stakeholders should regard this as a benchmark for considering other transmission options that might be more cost-effective. See Section 5.1 for a description of assumed transmission costs.

[c] Impact on expected unserved energy (EUE) estimated by increasing simulated load to the point where EUE is approximately 0.001% of load, then adding 3 GW of new renewable resources and remeasuring EUE. See Section 5.3 for an explanation of the resource adequacy methodology and scoring criteria.

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Oklahoma IREZ

Marginal levelized cost of energy using the zone's best 15 GW: $19.00/MWh

Destinations

- Atlanta and Greenville
- Little Rock and Birmingham

Oklahoma has an abundance of wind development areas with very low LCOE. A joint analysis for two or more destinations from the Oklahoma IREZ could identify several sources of additional savings, such as pathway consolidation, larger transmission configurations, different formulas for allocating delivered IREZ energy, and the use of short-distance AC network additions.

Hourly energy cost data were not available for Atlanta, and this might have reduced the estimate of energy cost savings in this analysis. Future analyses could develop hourly cost data and re-estimate energy cost savings.

IREZ planning should include Indian Tribes in western Oklahoma.

	Destination			
	Atlanta	Greenville	Little Rock	Birmingham
Energy cost savings[a] ($millions)	$338 *$405 with solar*[d]	$654	$581	$608
Annual revenue requirement for transmission[b] ($millions)	$264 *$421 with solar*[d]	$276	$186	$306
Benefit/cost ratio (energy savings only)	1.28 *0.98 with solar*[d]	2.37	3.12	1.99
Expected unserved energy (IREZ vs. local renewables)[c]	Similar *Much better with solar*[d]	Much better	Better	Better
3 GW as % of 2022 peak (included load zones)	10% (Georgia Power)	14% (all Duke Carolinas)	46% (Entergy Arkansas)	22% (Alabama Power)

[a] Based on actual local energy costs in 2022. Energy costs will almost certainly be different when an IREZ corridor is built and energized. Decision makers and stakeholders should consider how their own expectations for future energy costs in their areas might affect benefit/cost ratios going forward. See Section 5.2 for an explanation of the methodology used.

[b] Based on a 600-kV HVDC transmission line from the IREZ to the load center. Decision makers and stakeholders should regard this as a benchmark for considering other transmission options that might be more cost-effective. See Section 5.1 for a description of assumed transmission costs.

[c] Impact on expected unserved energy (EUE) estimated by increasing simulated load to the point where EUE is approximately 0.001% of load, then adding 3 GW of new renewable resources and remeasuring EUE. See Section 5.3 for an explanation of the resource adequacy methodology and scoring criteria.

[d] *Italics* show results for scenarios that include an HVDC connection from the Pueblo Southwest IREZ to the Oklahoma IREZ.

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ERCOT IREZ

Marginal levelized cost of energy using the zone's best 15 GW: $23.40/MWh

Destinations

- Little Rock
- Jackson and Birmingham
- New Orleans and Miami

AC network costs within ERCOT could add \$2 to \$5/MWh to the LCOE of IREZ resources; this is reflected in the ranges of energy cost savings shown below.

Hourly energy cost data were not available for Miami, and this might have reduced the estimate of energy cost savings in this analysis. Future analyses could develop hourly cost data and re-estimate energy cost savings.

Future analysis should test delivery to Little Rock using a back-to-back DC tie on the ERCOT periphery with an AC connection to Little Rock. This could be less expensive than the 600kV HVDC connection modeled in this analysis.

	Destination				
	Little Rock	Jackson	Birmingham	New Orleans	Miami
Energy cost savings[a] (\$millions)	\$508–\$554	\$515–\$561	\$541–\$586	\$547–\$593	\$533–\$578
Annual revenue requirement for transmission[b] (\$millions)	\$153	\$168	\$201	\$174	\$389
Benefit/cost ratio (energy savings only)	3.32–3.62	3.07–3.34	2.69–2.92	3.14–3.41	1.37–1.49
Expected unserved energy (IREZ vs. local renewables)[c]	Better	Better	Better	Better	Much better
3 GW as % of 2022 peak (included load zones)	46% (Entergy Arkansas)	54% Entergy MS, Mississippi Power)	22% (Alabama Power)	42% (Energy New Orleans and LA)	11% (FP&L)

[a] Based on actual local energy costs in 2022. Energy costs will almost certainly be different when an IREZ corridor is built and energized. Decision makers and stakeholders should consider how their own expectations for future energy costs in their areas might affect benefit/cost ratios going forward. See Section 5.2 for an explanation of the methodology used.

[b] Based on a 600-kV HVDC transmission line from the IREZ to the load center. Decision makers and stakeholders should regard this as a benchmark for considering other transmission options that might be more cost-effective. See Section 5.1 for a description of assumed transmission costs.

[c] Impact on expected unserved energy (EUE) estimated by increasing simulated load to the point where EUE is approximately 0.001% of load, then adding 3 GW of new renewable resources and remeasuring EUE. See Section 5.3 for an explanation of the resource adequacy methodology and scoring criteria.

New Mexico IREZ

Marginal levelized cost of energy using the zone's best 15 GW: $19.50/MWh

Destinations

- Phoenix
- Las Vegas

This IREZ covers the same wind and solar resource areas as a Western Renewable Energy Zone identified in a 2009 study for the Western Governors' Association. It is also the only IREZ in this analysis combining both prime-quality wind resources and prime-quality solar resources.

The corridor from the IREZ to the Phoenix area aligns with the 500-kV SunZia transmission project, currently under construction and expected to be complete in 2026. The California Independent System Operator has included in its study scenarios potential pathways similar to this IREZ corridor (CAISO 2023).

Existing 500-kV lines could provide connectivity from the Palo Verde/Phoenix area to Las Vegas and California.

	Destination	
	Phoenix	Las Vegas
Energy cost savings[a] ($millions)	$963	$966
Annual revenue requirement for transmission[b] ($millions)	$210	$247
Benefit/cost ratio (energy savings only)	4.59	3.91
Expected unserved energy (IREZ vs. local renewables)[c]	Much better	Much better
3 GW as % of 2022 peak (included load zones)	20% (APS, SRP)	45% (Nevada Power)

[a] Based on actual local energy costs in 2022. Energy costs will almost certainly be different when an IREZ corridor is built and energized. Decision makers and stakeholders should consider how their own expectations for future energy costs in their areas might affect benefit/cost ratios going forward. See Section 5.2 for an explanation of the methodology used.

[b] Based on a 600-kV HVDC transmission line from the IREZ to the load center. Decision makers and stakeholders should regard this as a benchmark for considering other transmission options that might be more cost-effective. See Section 5.1 for a description of assumed transmission costs.

[c] Impact on expected unserved energy (EUE) estimated by increasing simulated load to the point where EUE is approximately 0.001% of load, then adding 3 GW of new renewable resources and remeasuring EUE. See Section 5.3 for an explanation of the resource adequacy methodology and scoring criteria.

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Wyoming IREZ

Marginal levelized cost of energy using the zone's best 15 GW: $18.80/MWh

Destinations
Boise
Salt Lake City, Las Vegas, and California

This IREZ covers the same wind resource areas as a Western Renewable Energy Zone identified in a 2009 study for the Western Governors' Association.

All of the Wyoming IREZ corridors align with transmission projects that are already under construction or in advanced planning. Connections from Wyoming to Boise and to Salt Lake City align with the Energy Gateway Project. Connections from Wyoming to Las Vegas and California align with TransWest Express, the proposed Cross Tie Line, and repurposing of the existing Intermountain HVDC line.

Besides the connections shown here, the Boardman-to-Hemingway line would enable delivery of wind power from the Wyoming IREZ to Portland and Seattle.

	Destination				
	Boise	Salt Lake City	Las Vegas	Los Angeles	San Francisco
Energy cost savings[a] ($millions)	$1,079	$1,070	$1,045	$1,322	$1,376
Annual revenue requirement for transmission[b] ($millions)	$213	$172	$247	$281	$283
Benefit/cost ratio (energy savings only)	5.07	6.22	4.23	4.70	4.86
Expected unserved energy (IREZ vs. local renewables)[c]	Similar	Much better	Better	Better	Much better
3 GW as % of 2022 peak (included load zones)	73% (Idaho Power)	31% (PacifiCorp UT)	34% (Nevada Power)	7% (CAISO: SCE; LADWP)	9% (CAISO: PG&E)

[a] Based on actual local energy costs in 2022. Energy costs will almost certainly be different when an IREZ corridor is built and energized. Decision makers and stakeholders should consider how their own expectations for future energy costs in their areas might affect benefit/cost ratios going forward. See Section 5.2 for an explanation of the methodology used.

[b] Based on a 600-kV HVDC transmission line from the IREZ to the load center. Decision makers and stakeholders should regard this as a benchmark for considering other transmission options that might be more cost-effective. See Section 5.1 for a description of assumed transmission costs.

[c] Impact on expected unserved energy (EUE) estimated by increasing simulated load to the point where EUE is approximately 0.001% of load, then adding 3 GW of new renewable resources and remeasuring EUE. See Section 5.3 for an explanation of the resource adequacy methodology and scoring criteria.

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Montana IREZ

Marginal levelized cost of energy using the zone's best 15 GW: $20.90/MWh

Destinations

- Seattle
- Portland

Most of this corridor is near existing 500-kV transmission operated by Bonneville Power Administration. Alternative transmission configurations using this existing system might be more cost-effective than the new 600-kV DC line modeled here.

The Blackfeet Tribe has land in the Montana IREZ and should be included in IREZ planning. The path from the IREZ to the region's existing 500-kV network would likely pass through Flathead Tribe land; that tribe should also be included in IREZ planning.

	Destination	
	Seattle	Portland
Energy cost savings[a] ($millions)	$940	$939
Annual revenue requirement for transmission[b] ($millions)	$235	$236
Benefit/cost ratio (energy savings only)	4.00	3.98
Expected unserved energy (IREZ vs. local renewables)[c]	Better	Better
3 GW as % of 2022 peak (included load zones)	42% (Puget Sound, Seattle City)	70% (PGE)

[a] Based on actual local energy costs in 2022. Energy costs will almost certainly be different when an IREZ corridor is built and energized. Decision makers and stakeholders should consider how their own expectations for future energy costs in their areas might affect benefit/cost ratios going forward. See Section 5.2 for an explanation of the methodology used.

[b] Based on a 600-kV HVDC transmission line from the IREZ to the load center. Decision makers and stakeholders should regard this as a benchmark for considering other transmission options that might be more cost-effective. See Section 5.1 for a description of assumed transmission costs.

[c] Impact on expected unserved energy (EUE) estimated by increasing simulated load to the point where EUE is approximately 0.001% of load, then adding 3 GW of new renewable resources and remeasuring EUE. See Section 5.3 for an explanation of the resource adequacy methodology and scoring criteria.

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1 Introduction and Background

1.1 What Is an IREZ Corridor?

An **interregional renewable energy zone (IREZ)** is an area comprising a very high concentration of very low-cost developable renewable energy potential. An **IREZ hub** is a collection point on the bulk power system to which renewable energy plants built in the IREZ can connect easily. The hub anchors an **IREZ corridor** that consists of a dedicated high-voltage transmission path from the IREZ hub to a major load center. The transmission path covers a long distance, making low-cost renewables from the nation's best wind and solar regions accessible to load in another region hundreds of miles away. Zones focus on wind and solar because of their geographic economies of scale—it is possible to develop gigawatts of capacity with a single point of interconnection, making long-distance, large-capacity transmission more cost effective. Any type of generation may connect to an IREZ hub once the transmission is available, but for the purpose of examining the impact of a large interregional transmission line, we focus the analysis on wind and solar.

Renewable energy zones have proven successful for the cost-effective regional development of clean energy (DOE, 2021 at Appendix A). This study extracts lessons from these successes to devise a renewable energy zone model for interregional use in the United States. Examples of interregional transmission for renewables are very few, however, due at least in part to the fact that interregional transmission in general faces significant hurdles. As discussed in a companion report to this study, institutional practices bias transmission solutions toward local and regional projects and away from interregional solutions even in cases where the interregional solution might be more cost-effective, prudent, just, and reasonable for all electricity customers. Under current institutional constructs, the regulated entities who control the highly technical planning process are averse to regulatory risk, leading them to favor solutions for which there is a known precedent for cost recovery (Homer et al. forthcoming).

The companion report also observes that evolving conditions in the power sector, the U.S. economy, and the environment are converging to heighten the likelihood that, for the first time in many parts of the country, interregional transmission solutions could be increasingly cost-effective, prudent, just, and reasonable for all electricity customers. The combined effect of these transitional forces brings into play issues that traditional transmission planning objectives (congestion relief, reliability, and resource adequacy) do not address.

Some of the transitional forces at work are clear and present, such as increasingly frequent grid disruptions because of increasingly frequent extreme weather events such as hurricanes, wildfires, winter storms, and drought (NOAA, 2023). Other transitional forces have happened over time as a consequence of technological advancements, economics, and policy. Baseload coal generators are retiring while renewables, demand response, battery storage, and operationally flexible resources such as natural gas are increasing (EIA 2023a). Along with these supply changes is greater electrification of transportation and other sectors of the economy. As the Federal Energy Regulatory Commission (FERC) notes,

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> Due to continuing changes in both supply and demand, ongoing investment in transmission facilities is necessary to ensure the transmission system continues to serve load in a reliable and economically efficient fashion. … Proactive, forward-looking transmission planning that considers evolving supply and demand conditions more comprehensively can enable potential reliability problems and economic constraints to be identified and resolved before they affect the transmission system, which can facilitate the selection of more efficient or cost-effective transmission facilities to meet transmission needs. (FERC 2022)

In short, transmission approaches that might have been disregarded a few years ago might merit a fresh look today. Here we test how interregional transmission in the form of IREZ corridors might align with what the grid needs today.

Figure 1 illustrates the IREZ model. We standardize transmission assumptions for the purpose of analysis, using a single-circuit 600-kV high-voltage direct current (HVDC) transmission path running from an IREZ in a resource-rich region to a major load center in another region. This configuration tends to maximize the delivery of energy while minimizing transmission losses over a long distance. The HVDC has interconnections only at the converter terminals at either end of the line.[3]

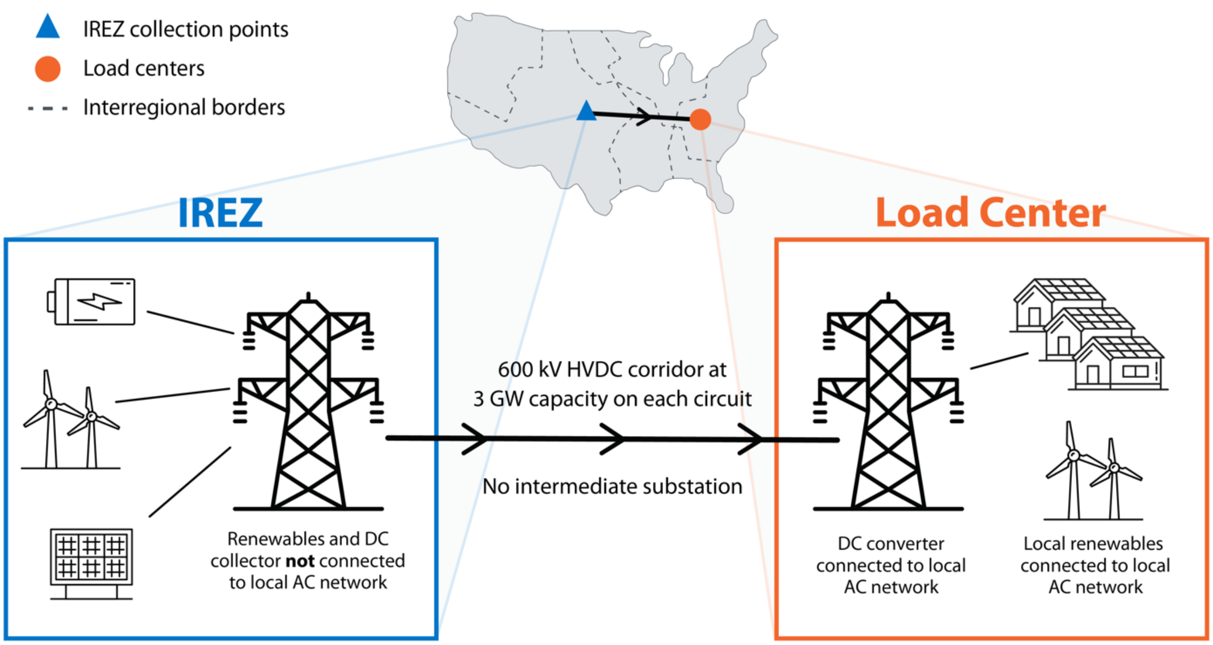

Figure 1. IREZ 600-kV HVDC corridor

[3] To simplify the analysis, we assume that the HVDC terminal at the IREZ hub has no connection to the local AC network and would therefore not affect operations under the local transmission operator's open access transmission tariff. However, there might be benefits to connections with the local AC network that affected parties could study if affected states decided to pursue a more detailed investigation of IREZ corridor development.

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A review of technical literature indicates the following:

- For distances covering several hundreds of miles, a 500- or 600-kV HVDC line generally has a lower cost per MW of transfer capability than a 500-kV high-voltage alternating current (HVAC) line. (WECC 2019)

- A single-circuit 600-kV HVDC line has a maximum transfer capability of about 3 gigawatts (GW) and a loss factor of 11.5 MW for every 100 miles of line distance. A 500-kV double-circuit HVAC line has about the same nominal transfer capability but loses nearly twice as much energy along the way (WECC 2019).

We use 3 GW, the transfer capability of a 600-kV HVDC line, as the unit of analysis for this study. This configuration makes it possible to standardize the analysis, but we recognize that different configurations might yield greater cost savings. We anticipate that if affected states instruct their utility transmission planners to consider options for an IREZ corridor, planners will examine several alternative transmission configurations for delivering power.

IREZ resources would be one part of the load center's overall resource mix. Local resources close to load would connect to the local AC network and would not be affected by the corridor. State and local decision makers would determine the appropriate mix of IREZ resources, local renewables, offshore wind, and other resources.

As noted by FERC and others, the transitional forces that are currently affecting the nation's electricity sector might necessitate new approaches to transmission planning. The goal of this study is to adapt a historically successful transmission planning model so that it might meet new challenges. The next section describes some of the lessons from the first use of renewable energy zones in transmission planning.

1.2 Lessons From the Texas CREZ Model

Texas' competitive renewable energy zone (CREZ) model was the first application of renewable energy zones to systemwide transmission planning. CREZs were multi-county areas in western Texas where the expected capacity factors of wind plants were very high based on historical meteorological data. Once the Public Utilities Commission of Texas (PUCT) designated final CREZs, planners at the Electric Reliability Council of Texas (ERCOT) developed transmission options for connecting CREZ resources to the grid.

The Texas wholesale power market is unique in several ways, and the Texas CREZ model was tailored to that market. Although replicating it in detail nationwide would be infeasible, the Texas CREZ model does provide crucial lessons that we have applied to the IREZ analysis.[4]

Perhaps the most important insight is that renewable energy zones do not create new demand for renewables. Rather, they use new transmission to *redirect* future development intended to meet

[4] The infeasibility of a copy-and-paste replication of CREZ has to do primarily with differences in regulatory jurisdiction. Implementation of the CREZ model followed requirements established by Texas state law for ERCOT, which is a single-state electricity market (Texas Legislature 2005). Other U.S. markets are under FERC jurisdiction, and the use of IREZs would involve collaboration among multiple states.

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demand that already exists to sites that are the most productive and will result in greater savings to customers. Renewable energy growth may be driven by state policy, consumer demand for clean energy options, the need for a more diverse resource portfolio to support reliability, or a more general need to replace retiring resources and maintain resource adequacy. Some of that potential renewable energy growth might be pent up because of insufficient opportunities for interconnection, or it might be forced into sites where wind or solar resources are poor and the cost per kilowatt-hour is high. Whatever might drive demand, renewable energy zones create alternatives for obtaining new supply that are economically superior to what would be available without the zones.

1.2.1 The Value of Aggregating Demand in a Single Large Market

In Texas, the planning target for CREZ renewables was not a single off-taker but demand throughout all of the ERCOT market. Planning for a large volume of demand in a single target market demand introduced economies of scale: Larger generation projects were feasible; higher-voltage lines with fewer losses and lower costs per megawatt per mile were utilized more fully. On the supply side, CREZs contained several times more megawatts in resource potential than ERCOT was likely to need. The surplus potential accelerated competition among suppliers to build the best projects at the best sites. Every competing generator risked being economically substituted by another, and no individual generation developer had a strong enough lock on the market to shut out competitors. The market was fully contestable.

These two economic forces—competition and economies of scale—were crucial CREZ elements, and we apply these principles to the IREZ model. This contrasts with project-by-project procurement on a legacy transmission network where competition is limited and economies of scale are often out of reach.

Besides these efficiencies, the operational attributes of a single large load center—particularly peak load, daily load profiles, and the cost of generation alternatives—can help determine which IREZ is the best fit for the load center based on hourly renewable energy production profiles and hourly differences in the load center's marginal cost of energy.

1.2.2 The Value of Stronger and Earlier Public Sector Engagement

An affirmative declaration of policy by the State of Texas to expand renewable energy procurement through strategic transmission expansion was the spark that ignited CREZ competition (Texas Legislature 2005). CREZs became a defined space for entrepreneurial dealmaking with local landowners and other authorities for site access and fair compensation. State policy also sent an unambiguous signal to ERCOT planners to develop transmission options for integrating CREZ resources into the network.

Texas officials solicited evidence of commercial interest to guide the selection of final CREZs. Measures included signed land leases or options, previous development, letters of credit, and other tangible costs incurred by a developer (PUCT 2016).

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1.2.3 The Value of Anticipating Prospective Needs

Determinations of "just and reasonable" transmission investments increasingly depend on circumstances that change over time, sometimes with a large degree of uncertainty. In the Texas CREZ proceeding, the Texas Commission used reliability and cost criteria to determine how much future demand a final CREZ transmission plan should accommodate. It also considered the possibility that future market demand for renewables might outstrip the capacity mandates that were in place at the time. The Texas Commission determined that the public interest would be served best by a CREZ transmission plan that would accommodate some degree of market-driven future demand, rather than a plan that—because of its limited transfer capability—would effectively cap renewable energy growth at the state mandates (PUCT 2008).

Market-driven demand for Texas renewables turned out to be robust, and the outcome was a net cost savings for customers. The line item for transmission charges on customer bills increased by about 0.6 cents per kilowatt-hour by the time the last CREZ element was completed in 2013 (PUCT 2013). Over the next 7 years, wind power tripled in both capacity and its contribution to the ERCOT resource mix (EIA 2023b; ERCOT 2020). This helped reduce real-time wholesale energy prices from an average of 4.6 cents per kilowatt-hour during the CREZ buildout to an average of 3.3 cents per kilowatt-hour over the 7 years following the CREZ buildout (Potomac Economics 2020). Overall rates paid by retail customers in Texas remained steady, while those paid in the rest of the country increased (EIA 2023c).

In today's electricity sector, certainty is increasingly elusive for many aspects of grid planning. Nevertheless, observable improvements in technology make reasonable forecasts possible (NREL 2023). Texas' CREZ experience suggests that states have an important role in deciding how to manage uncertainty in a way that reasonably accommodates the public interest.

1.3 States as the Primary Audience for This Study

This analysis focuses primarily on states: those where wind and solar resources can be developed in bulk at the lowest possible cost per megawatt-hour and states where such resources are likely to have the greatest value when delivered to customers. We assume that states affected by a high-value IREZ corridor would collaborate on regulatory approval and compel their transmission planning entities to include the interregional line in capacity expansion plans, if all affected states determine that the IREZ corridor is in the public interest.

The aim of this study is to provide states with a common knowledge base so that the analysis of costs and benefits is equally credible among all affected states. Examples of common technical inputs are wind speed and solar irradiation provided by the National Renewable Energy Laboratory's (NREL's) most recent analyses of satellite data and surface meteorological measurements. Decisions on other more subjective assumptions, however, are left for states to make themselves. For example, we make no assumption about how a receiving state should combine IREZ renewables and local renewables in its resource mix. Nor do we estimate what percentage of a state's load that IREZ renewables should serve. States make such decisions based on their assessments of the public interest, consistent with state laws and considering stakeholder comments. Our objective for the IREZ analysis is to inform state processes—not to stand in for them.

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This analysis does not replace the modeling and other technical analysis transmission planners would do once they receive state direction to study an IREZ corridor. Evidence from this study may, however, lead a state to engage more closely in the early stages of IREZ transmission planning. Many state utility commissions have limited resources and therefore cannot engage in all aspects of transmission planning. This analysis can help inform states as they engage in the utility's planning process.

1.4 IREZ Benefits

IREZ corridors have four potential benefits for receiving states: emission reductions, energy cost savings, improvements in resource adequacy, and augmented resilience against grid outages resulting from extreme climate events and other causes. For source states, potential benefits include increased tax revenues and more local employment.

We do not, however, monetize and combine these benefits into an aggregated estimate of net savings. Some benefits are difficult to monetize. In addition, the monetized value of one type of benefit might not be comparable with another type due to different assumptions and methodologies. Different benefits play a different role in estimating the value of transmission, and we keep them disaggregated so that states might more easily evaluate each.

- **Energy cost benefits** measure the delivered cost of IREZ renewables per megawatt-hour against energy costs in the load center. This accounts for the expected volume of energy production in the IREZ during each hour of a typical meteorological year as well as the load center's hourly and seasonal cost of energy. Because these savings would accrue in the future after the completion of the transmission, however, estimating them entails inherent uncertainty. Here we take a "backcasting" approach, calculating what the potential savings *would have been* had the investments been in place for 2022 with the known energy production costs for that year. We assume that a state considering IREZ development would make its own determination of likely future energy costs in a public proceeding with opportunity for stakeholder input on trends for load growth, fuel prices, generator retirements, and other factors affecting the cost of energy production in 2035. The backcast estimates in this analysis serve as an anchor point to rationally account for the uncertainty of future energy savings.

- **Resource adequacy benefits** measure how effectively one megawatt of a resource reduces the probability of unserved energy in the load center. The relevant comparison for this analysis is local renewable resources against IREZ resources, focusing on the IREZ matched with the load center based on energy cost savings. The measure is the difference in the impact on unserved energy.

- **Resilience benefits** refer to the ability of long-distance resources delivered via interregional transmission to keep the lights on if an extreme disruption—hurricanes, wildfires, and winter storms, for example—causes widespread forced outages at generators on the load center's local network. While there is agreement that interregional

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transmission has a nonzero value for enhancing resilience (DOE 2023)[5], there is little consensus on how to measure it. We do not propose a methodology here, because doing so would be far outside the scope of this study. However, we do posit that if the benefits of savings in generation cost and of greater resource adequacy outweigh the cost of IREZ transmission, resilience would be a bonus benefit regardless of how it is measured.

- **Benefits in emission reductions** are part of the policy envelope in which state and local authorities evaluate the previous three benefits in transmission cases. Emission benefits are not monetized in this analysis, but they are assumed to be a policy driver for decarbonizing the grid.

1.5 Decarbonization Trends

This analysis contains no assumption about a possible national decarbonization mandate. We note, however, that the power sector is evolving naturally away from carbon-intensive technologies to reduced-carbon and emission-free technologies. To the extent this is a trend affecting the current and future use of capital, demand for renewable energy is likely to continue growing because of underlying transformation of the electric sector (Homer et al. forthcoming).

If an IREZ sufficiently reduces the cost of energy and improves resource adequacy for a major load center, it could serve as an early response on the path to whatever decarbonization goal might be in force. Decarbonization will most likely require an array of responses that would be implemented over time, based on the technical feasibility and cost-effectiveness of the available options. The results of this analysis help understand when and where IREZs might be an early response to continued decarbonization.

1.6 Offshore Wind

Like onshore wind and solar, offshore wind is a bulk renewable resource that can be developed at gigawatt scale at one point of interconnection. However, assessing offshore wind involves methods different from those used to examine IREZs. These analytical methodologies do not overlap nor do they exclude one another. Therefore, a state may choose to include both in its resource mix.

New York and New Jersey have state policies for procuring 16.5 GW of offshore wind by 2035.[6] This raw capacity equals about 29% of 2035 peak demand for these two states, based on load forecasts used in the NTP Study's accelerated electrification scenarios.[7] Offshore wind targets for the New England states amount to about 21% of forecasted 2035 peak load. An IREZ corridor consisting of one or two HVDC circuits could provide an additional measure of

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[5] Among the major challenges to monetizing the value of resilience: agreeing on the economic value of a human life (pertinent to extreme disruptions that result in attributable deaths); assigning the appropriate probability and discount rate to the event; and anticipating economic losses related to supply chain impacts when outages last days rather than hours.

[6] Where the analysis in this report relies on load forecasts, we use 2035 forecasts from capacity expansion modeling conducted under the NTP Study. These forecasts were vetted with regulators and other state officials (DOE forthcoming).

[7] We use nameplate capacity numbers in this paragraph as a general illustration of how the anticipated capacity compares to a region's expected demand. These resources' probable contribution to peak demand is smaller and involves an analysis of resource adequacy, which we provide in Section 5.3.

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renewable energy capacity equivalent to 5% to 10% of the New York–New Jersey 2035 peak load. For New England, a single IREZ corridor would be about 21% of the forecasted 2035 peak. These numbers suggest room for both offshore wind and IREZ renewables in the future resource mix.

1.7 ERCOT

ERCOT is unique among other wholesale markets in the country, and its uniqueness affects interregional transmission. The crucial fact is that ERCOT is under the jurisdiction of the State of Texas, not FERC. The legal foundation for Texas jurisdiction is the lack of significant interstate commerce in electricity between ERCOT and any neighboring state.[8]

An interregional transmission line originating in ERCOT and delivering electricity to another state could conflict with the legal rationale for maintaining Texas jurisdiction over ERCOT. We account for ERCOT's regulatory uniqueness by treating the entire independent system operator (ISO) as a renewable energy zone that aggregates zonal clusters.[9] Wind or solar ultimately used in another state may come from any zone inside ERCOT, if it is transmitted across the AC network to a point on the ERCOT periphery. These transfers would remain under state jurisdiction and would follow ERCOT protocols. At the perimeter, the energy would be delivered at a load node. The energy would pass through a DC converter station and onto a long-distance 600-kV HVDC line that would carry the power to a load center in another state. We assume that the converter station and the HVDC line would operate under a FERC jurisdictional tariff. This approach is consistent with a transmission model that has been approved both by FERC and by the Public Utilities Commission of Texas (FERC 2014).

In short, the delivery of renewable energy from the ERCOT IREZ to load in another region would occur over an interstate DC transmission line that would originate on the ERCOT periphery. The levelized cost of energy (LCOE) of ERCOT wind and solar includes a special transmission adder ($2 to $5/MWh) that accounts for the cost of using the ERCOT network (transmission service charges and costs associated with transmission congestion) to deliver wind and solar to a load node on the edge of ERCOT where the DC line would begin.

1.8 IREZ in the NTP Study: Top-Down Versus Bottom-Up Analysis

The IREZ corridor analysis is a component of the NTP Study. It is intended as a bridge between the top-down national analysis conducted in the NTP Study and the bottom-up decision-making processes that state authorities often apply. Scenarios in the NTP Study use the same wind and solar resource data used in the IREZ analysis, and both apply the same load growth forecasts that were vetted through state officials for review and comment. The methodologies that use this information to identify transmission pathways, however, are different from and independent of one another.

[8] The Texas Interconnection is not synchronously connected with either the Eastern or Western Interconnections. The transmission network and wholesale market operated by ERCOT completely coincides with the Texas Interconnection and does not extend beyond it.

[9] The first phase of the IREZ analysis (Hurlbut et al. 2022) identified 18 preliminary zones inside ERCOT. These were combined into a single aggregate zone comprising the same screened resources.

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Results from NTP Study scenario analyses are national optimizations of a unified national grid. In one sense, results represent the maximum economic impetus for new transmission and new generation under assumptions that are tested for all regions simultaneously—an "everything everywhere all at once" simulation that captures the interdependencies between regions and states. If, for example, a scenario indicates 20 GW of new transmission capability from one region to another, that 20 GW represents the maximum efficient transmission buildout along that pathway in a perfect world with only the constraints that were included in the model.

An IREZ corridor resembles an imperfect but more realistic model where transmission decisions are made separately, not all at once. Costs and benefits focus on the load that would pay for IREZ transmission. Where the IREZ and NTP Study results coincide, the IREZ corridor conceptually represents a portion of the transfer volume that the NTP Study identifies from one region to another. Say, for example, the nationwide capacity expansion scenarios in the NTP Study indicate an economic appetite for 20 GW of new transmission capability from one region to another, and that one of these regions also has an IREZ and the other is a load center at the end of an IREZ corridor. The IREZ corridor's 3 GW of transfer capability would be a slice of the 20 GW identified in the global analyses.

Therefore, this IREZ analysis does not contradict any finding from the NTP Study's national modeling, but it does provide a deeper glimpse into pieces of those findings that are recognizable to state decision makers. The IREZ corridor would not be all of what the NTP Study identifies for the pathway, but it does have a crucial characteristic that the national optimization lacks: It represents a specific element of the national picture that is fully in the regulatory line-of-sight of the state whose residents would bear the cost of the line.

1.9 How To Use This Study

We structured this analysis to help answer a threshold question for groups of states affected by an IREZ corridor:

> *Could the cost of a long-distance interregional transmission corridor be just and reasonable relative to its expected benefits?*

The definitive answer would come at the end of state collaboration and regulatory proceedings that would formally account for all the uncertainties affecting the ultimate assessment of public interest. The aim here is to provide an initial knowledge base that can spark subsequent investigation by states and stakeholders. This study can inform expectations for the following key questions:

- How much of a load center's future generation mix could IREZ resources provide?
- Would IREZ resources result in a net savings in energy costs?
- Would IREZ resources improve resource adequacy and help protect affected states from grid disruptions caused by extreme climate events?
- Would IREZ resources help states achieve their goals for decarbonization in a cost-effective manner?

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- Do the benefits to load provide sufficient economic headroom to compensate landowners for right-of-way along the corridor?

State policymakers may also develop consensus on principles for the distribution of benefits and the allocation of costs. Benefits could include assumptions about local tax receipts and indirect economic development effects in the IREZ state, payments to landowners for the acquisition of right-of-way (ROW) along the transmission path, net savings in energy costs for customers at the receiving end of the corridor, and enhanced resilience against extreme weather events. States could also set expectations for the financial participation of entities who are not jurisdictional transmission utilities (e.g., power marketing administrations, independent transmission developers, and tribal energy enterprises).

States should also anticipate the need for further study that would account for state- and corridor-specific issues that this study could not address.

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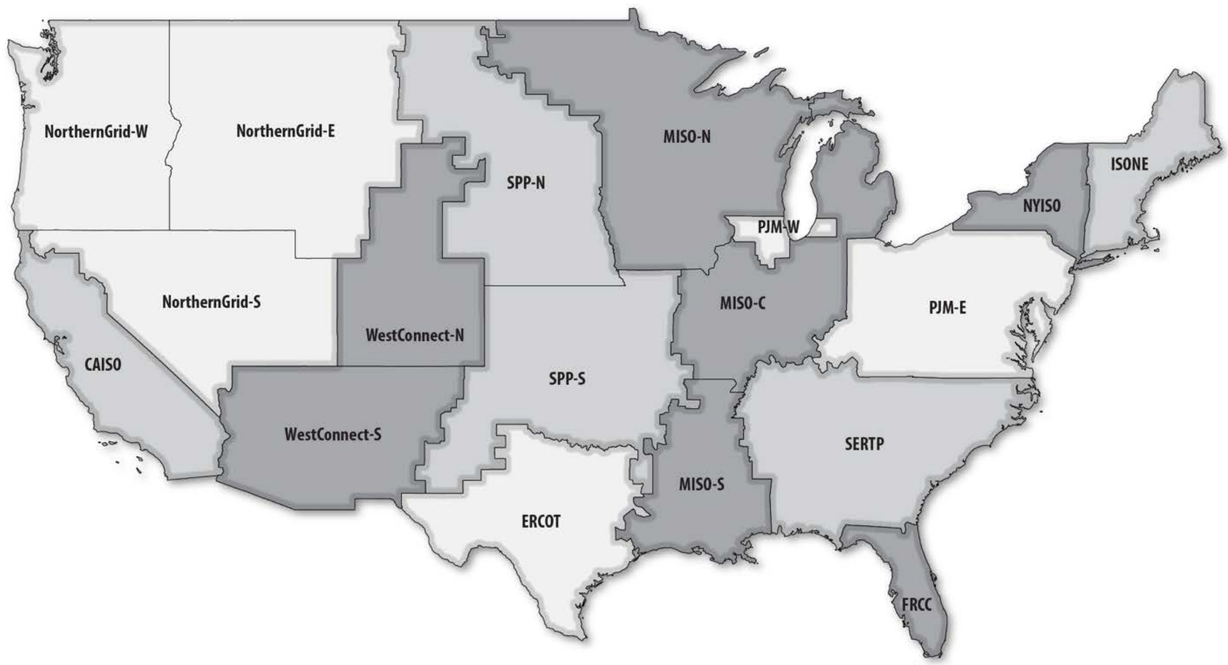
2 IREZ Selection

The first step in the selection of IREZs was to identify the best clusters of wind and solar potential in each transmission planning region (Hurlbut et al. 2022). Figure 2 shows the transmission planning regions used in the preliminary analysis.



Map by Billy Roberts, NREL. Phase 1 of the IREZ study analyzed single regions for NorthernGrid, WestConnect, and SPP. The three MISO subregions were analyzed separately.

Figure 2. Transmission planning regions used in preliminary IREZ identification

The resource clusters constitute the renewable energy zone. We used NREL's Renewable Energy Potential (reV) model to estimate the LCOE of sites across a wide area and to identify contiguous clusters of sites with low LCOE. LCOE captures site-specific variations in resource quality (average annual wind speed or average annual insolation) applied to standard assumptions for capital costs, financing parameters, and operating costs.[10] Higher resource quality results in more megawatt-hours per dollar of investment and therefore a lower cost per megawatt-hour.

We also identified the centroid of each cluster, considering the varying LCOE of resource areas in the cluster and the distance of a generation tie line (gen-tie) from a site to the centroid.[11] The centroid served as a proxy for the zone's hub: the point that could connect the greatest amount of capacity at the lowest LCOE (cost per megawatt-hour at the project site plus gen-tie costs).

[10] The reV model uses cost inputs from NREL's Annual Technology Database (NREL 2023). Phase 1 of the IREZ study used 2021 prices from the 2022 version of the database, and for consistency we used the same historical costs in this phase. We assumed wind plants using 5.5-MW turbines at a hub height of 120 meters, and photovoltaic plants using single-axis tracking. For detailed cost assumptions, see NREL 2023 (archived spreadsheets for 2021).

[11] Throughout this study, references to LCOE include gen-tie costs.

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Although the zone has no boundary per se, as a practical matter sites farther from the centroid are more expensive to develop because of the additional gen-tie costs and declining resource quality.

The second step of IREZ selection, conducted in this phase of the study, was to compare these preliminary zones with one another nationwide and eliminate the ones that did not meet more rigorous national criteria. The test for each preliminary zone involved measuring its prime resources, where we defined "prime resource" to mean:

- Undeveloped wind resource areas with an LCOE less than $20/MWh
- Undeveloped solar resource areas with an LCOE less than $24/MWh.

To be a final IREZ, the zone had to contain at least 4 GW of prime resource potential.

The last step in developing a roster of final IREZs was to combine preliminary zones where appropriate and reapply the LCOE screening criteria. Because the analysis of preliminary zones used transmission planning regions as the unit of analysis, there were some instances where two zones were across from one another along an interregional border. We combined such pairs into a single IREZ because (a) the two zones represent the same wind or solar regime and (b) the boundary between regions carries little importance for a long-distance interregional transmission line.

We also combined IREZs within the same state that were close to one another. In some cases (Montana, North Dakota, South Dakota, and Iowa), aggregating zones with smaller amounts of prime resources made it possible to meet the 4-GW minimum threshold.

For reasons explained in Section 1.6 above, all of the zones in ERCOT that passed the screening for prime resources were combined into a single IREZ. For this analysis, we assume that prime resources from any zone in ERCOT would use the local AC network to move energy from the plant to the ERCOT perimeter. This essentially makes the entire ERCOT footprint an IREZ. The IREZ corridor would begin not at a hub, but at a large DC converter station that would connect to an HVDC line on the ERCOT periphery to another region.

Figure 3 shows the 19 IREZs—18 hubs plus ERCOT—that passed the final screening. Figure 4 and Figure 5 show how these zones align with the country's solar and wind gradients.

Most of the IREZs are primarily wind. Five are solar, and one—New Mexico—has prime wind and solar. The Pueblo Southwest IREZ has the largest amount of solar potential with an LCOE less than $24/MWh and a considerable amount that is less than $23/MWh. Other solar IREZs are Southern California, Southwestern Arizona, Northeastern Arizona, and Southern Nevada.

As discussed in Section 4 below, some of the IREZs that passed the final screening ultimately were not paired with any load center. This was because of three economic factors used in the matching algorithm: the quantity of demand included in the matching analysis, the LCOE of resources in an IREZ's supply curve (discussed in the next section), and the distance from the IREZ to the load center (longer distances were more costly and less competitive).

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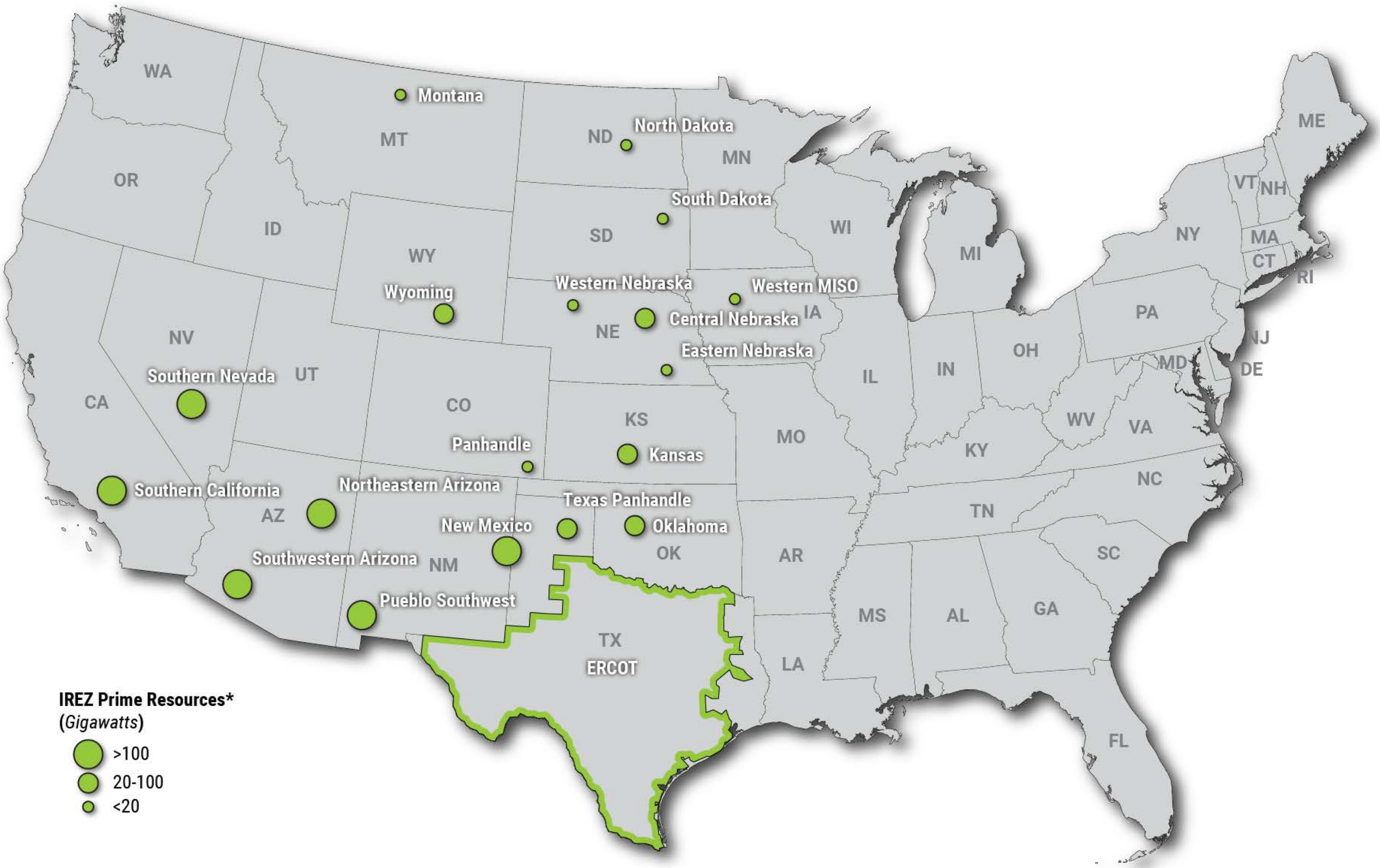

Map by Billy Roberts, NREL

Figure 3. IREZs remaining after application of additional economic screens

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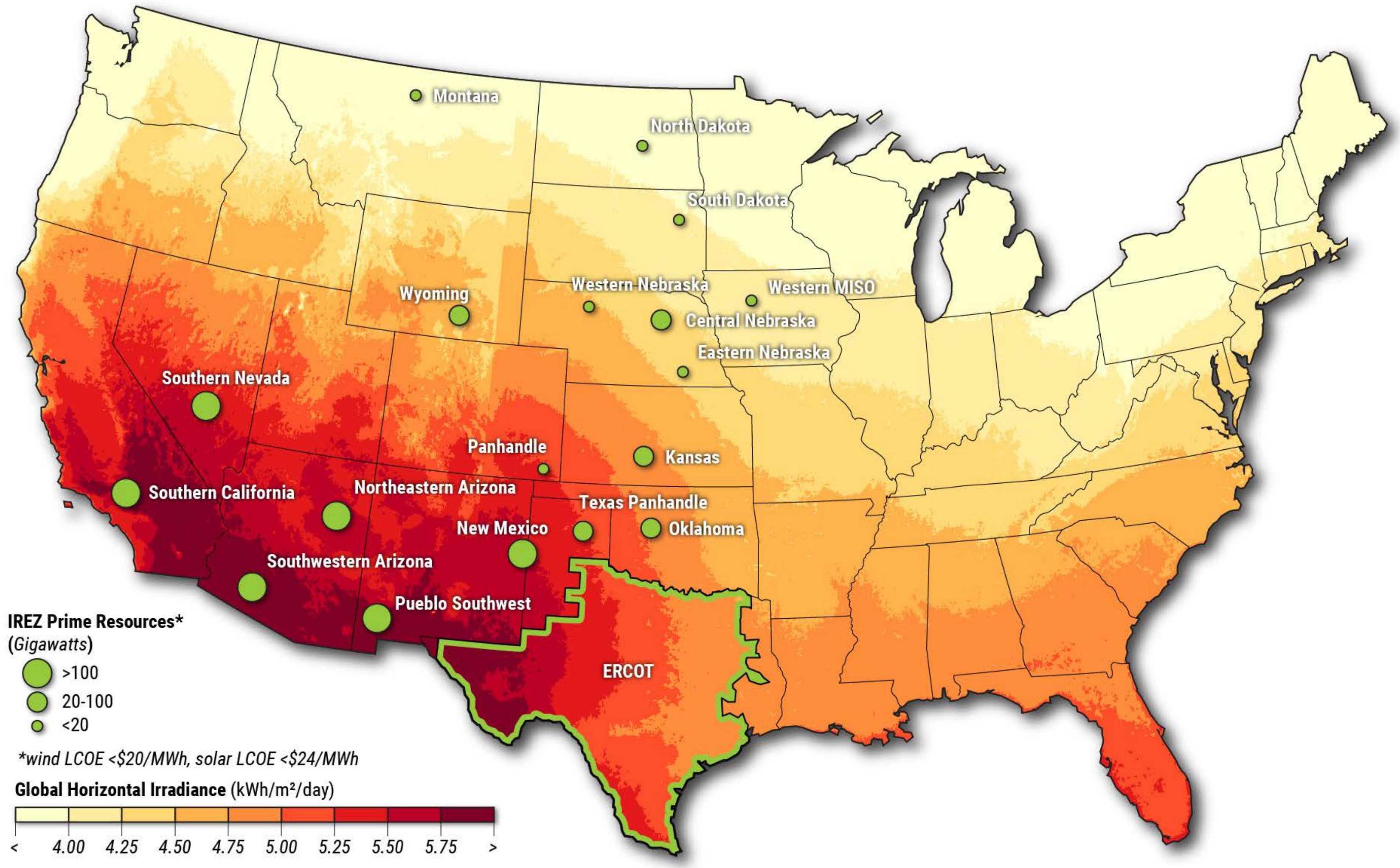

Map by Billy Roberts, NREL

Figure 4. IREZs and U.S. solar resources gradients

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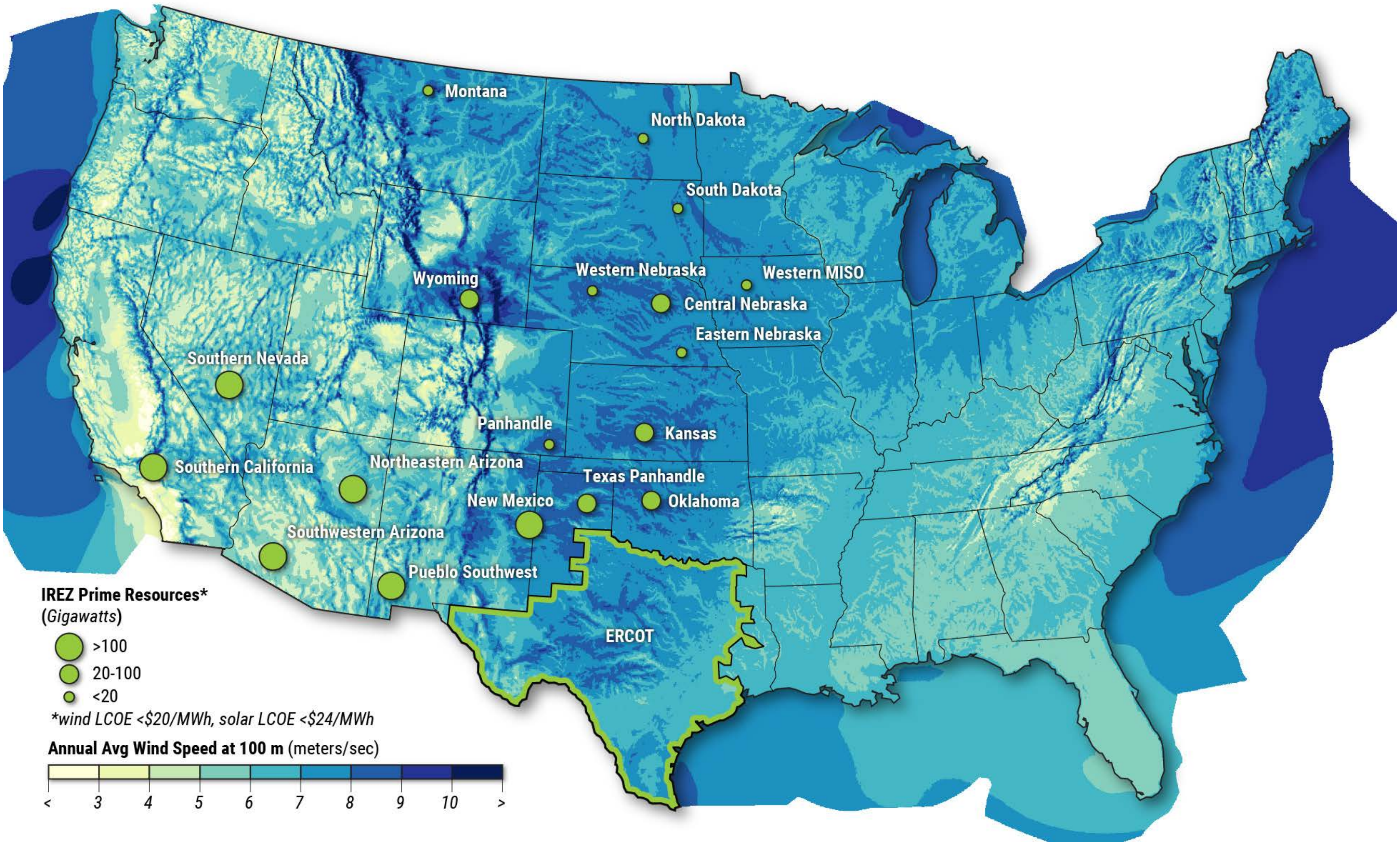

Map by Billy Roberts, NREL

Figure 5. IREZs and U.S. wind resource gradients

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2.1 Supply Curves

Each IREZ has a supply curve representing the wind and solar resources that can be collected economically at a central hub. The curve orders all undeveloped potential resource sites in the zone by their computed LCOE (including gen-tie costs), from least expensive to most expensive; the vertical axis is the LCOE, the horizontal axis is the cumulative potential generation capacity in the zone that can be developed at or below the corresponding marginal LCOE.

Figure 6 shows the supply curve for the New Mexico IREZ. It has about 32 GW of prime quality wind potential (an LCOE less than $20 per MWh), 112 GW of prime quality solar potential (an LCOE less than $24 per MWh), about 100 GW of other wind resources, and more than 400 GW of other solar resources.

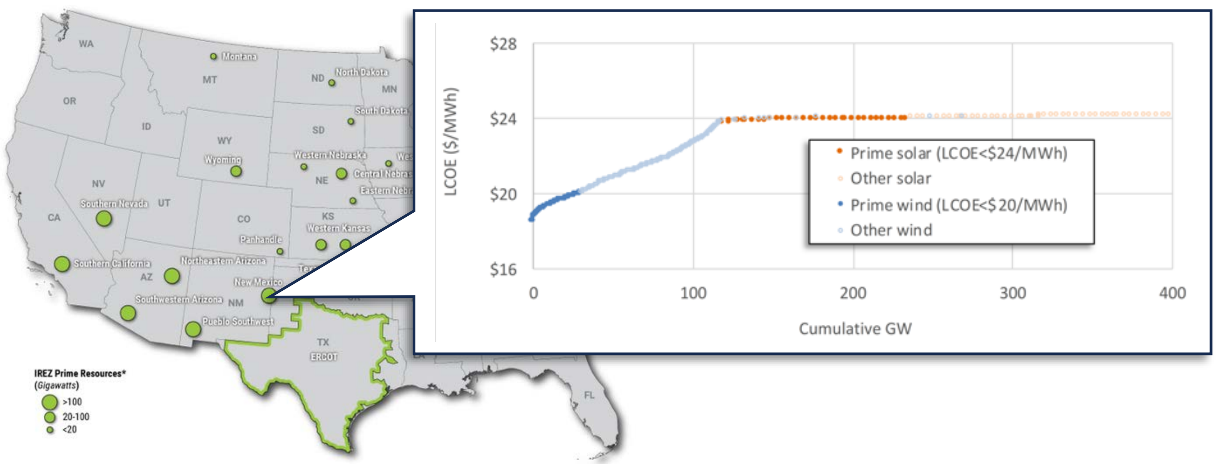

Figure 6. New Mexico IREZ supply curve

LCOE is not a reliable predictor of the actual development cost of a specific site. However, it is a useful metric for measuring the quality of renewable energy potential across a wide area. LCOE essentially monetizes values for average annual wind speed or insolation at all sites, holding constant assumptions about capital costs, financing, and other factors (NREL 2023).[12] Applied over a large area such as an IREZ, an LCOE supply curve describes the competitive space for renewable energy development. Using the New Mexico example, wind generation developers would theoretically examine all prime quality sites in the zone—which in this case amount to 32 GW—and compete for access to the 3 GW of IREZ transmission capability. This analysis does not select specific development sites, but we do posit that entrepreneurial innovation in reducing project costs will tend to push actual costs toward the lower end of the supply curve.

Table 1 lists each IREZ and the amount of its prime wind and solar resources. Each IREZ in fact contains hundreds of gigawatts of renewable energy potential, but Table 1 uses only prime resources for comparison.

[12] NREL's Annual Technology Database provides generic cost estimates for most commonly used generation technologies, updated annually. For this analysis, we assumed wind plants using 5.5-MW turbines at a hub height of 120 meters, and photovoltaic plants using single-axis tracking. For detailed cost assumptions, see NREL 2023.

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Table 1. Prime Wind and Solar Resources in IREZ Supply Curves

IREZ	GW of prime wind (LCOE<$20/MWh)	GW of prime solar (LCOE<$24/MWh)
Pueblo SW	-	1,722
Southwestern Arizona	-	609
Southern Nevada	-	266
New Mexico	32	112
Southern California	-	138
Northeastern Arizona	-	127
Oklahoma	45	-
ERCOT	40	-
Wyoming	38	-
Texas Panhandle	30	-
Western Kansas	27	-
Central Nebraska	26	-
Eastern Kansas	21	-
Eastern Nebraska	17	-
Western Nebraska	12	-
Western MISO	11	-
North Dakota	6	-
Panhandle	6	-
South Dakota	4	-
Montana	3	-

2.2 Adjustments for ERCOT

As explained in Section 1.7 above, ERCOT has unique regulatory circumstances that suggest unique treatment in this analysis. Although all other IREZs are single-point collection hubs, we treat ERCOT as a region within which are numerous concentrations of high-quality wind and solar resources. We assume the following:

- Wind and solar plants located in ERCOT can deliver energy to an IREZ transmission corridor. They would do so by using the ERCOT network to deliver their output to a large load node on the ERCOT periphery. Delivery from the plant to the load node would be an ERCOT energy transaction under Texas state jurisdiction.

- The load node on the ERCOT periphery would be adjacent to the terminus of the IREZ corridor. Energy would move from the load node through an adjacent DC converter station and onto the IREZ corridor to a load center in another state. The converter and the DC transmission line would be under FERC jurisdiction.

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- Use of the ERCOT network would entail additional costs, represented as an adder to the LCOE of the wind and solar plants providing energy for the IREZ.

ERCOT network costs include two components: the tariff of the local transmission provider and the cost of transmission congestion between the generator and the load node on the periphery. We use $1 per MWh as a generic tariff cost, based on approved tariffs in effect as of 2023 (PUCT 2023).

Estimating the applicable congestion cost is much more problematic. In 2022, the systemwide cost of congestion in ERCOT was $5.37 per MWh (Potomac Economics 2023a). For the first 8 months of 2023, congestion costs were trending 73% of costs for the same period in 2022 (Potomac Economics 2023b). Data for 2020 and 2021 are not useful for calibration because of the effects of the COVID-19 pandemic and the disruptive impacts of Winter Storm Uri. Two important conditions also affected congestion pricing in ERCOT significantly in recent years. First, the amount of wind and solar capacity in ERCOT's west zone increased by about 10 GW, creating new congestion pressure on the flow of energy from West Texas to the rest of ERCOT. Second, natural gas prices from 2015 to 2019 were about half of what prices were in 2022. Congestion prices in ERCOT are correlated with the price of natural gas; therefore, expectations about the persistence of high gas prices would affect expectations for future congestion prices.

For the overall IREZ analysis, we tested adders of $2 to $7/MWh to the LCOE of all ERCOT wind and solar within ERCOT, and selected $2 to $5/MWh as the plausible range for this analysis. These adders are explained in Section 4.4 below.

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3 Selection of Load Centers

The identification of potential delivery points for resources from an IREZ began with identifying each state's largest population center based on U.S. Census data (U.S. Census 2020).

If a state also contained an IREZ with prime wind resources (where prime resources are those with an LCOE less than $20 per megawatt-hour), we assumed that the state had access to low-cost renewables locally without relying on a long-distance HVDC transmission line. These load centers were dropped from the interregional analysis.

Three states—California, Arizona, and Nevada—had an abundance of prime-quality solar resources but little or no in-state prime wind resources. We assumed that these states might beneficially mix local solar with IREZ wind, which we tested by keeping these states' load centers in the analysis.

We assumed further that a single delivery node in a multistate RTO could serve more than one state. Boston, for example, is the largest load center in ISO-New England. A 3-GW connection to eastern Massachusetts could therefore affect the supply mix for all the New England states combined. This made Boston a representative load center for all of ISO-New England. Other combinations within an RTO were as follows:

- Washington, D.C., Virginia, Maryland, and Delaware in eastern PJM
- Ohio, Pennsylvania, Kentucky, and West Virginia in central PJM.

We divided the MISO footprint into three subregions corresponding to the RTO's three reliability zones. The states in MISO North (North Dakota, Minnesota, and Iowa) have local access to IREZ-quality resources, and for this reason we did not include these states as demand centers for an interregional corridor. States in the other two regions had no IREZs, and we treated each as a load center.

Chicago and Milwaukee are in different RTOs but are nevertheless about 80 miles from one another. We combined these load centers by assuming delivery to a point halfway in between, near the Wisconsin-Illinois border.

Finally, we included two load centers for California—Los Angeles and San Francisco—that would both be served by way of an IREZ interface from Las Vegas into eastern CAISO.

Figure 7 shows the load centers we included in the analysis of IREZ corridors. Table 2 describes key attributes of the load centers.

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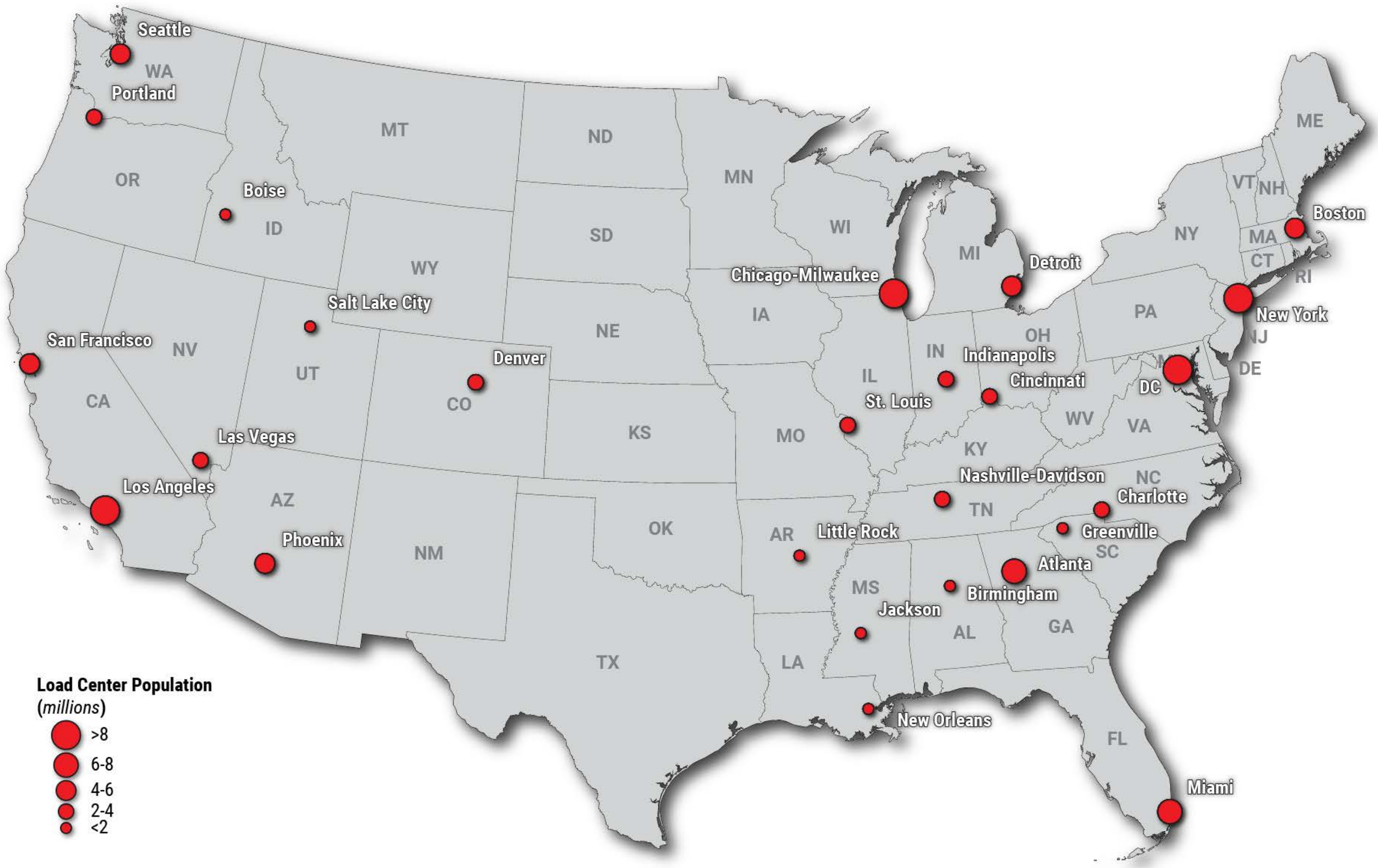

Figure 7. Load centers included in the analysis as destinations for IREZ resources

Table 2. Load Centers Included in IREZ Analysis

Metropolitan area (load zones included)	2022 peak (GW)	3 GW as % of peak	Expected growth by 2035 (%)
Washington, D.C. (PJM: PEPCO, BGE, Dominion)	34.6	9%	26%
Nashville (all of TVA)	33.4	9%	29%
New York (all of NYISO)	32.1	9%	30%
Los Angeles (LADWP, CAISO-SCE)	31.2	10%	61%
Atlanta (Georgia Power)	29.5	10%	39%
Chicago-Milwaukee (PJM: Com Ed; MISO: We Energies)	27.5	11%	35%
Miami (FP&L)	26.7	11%	27%
Boston (all of ISO-NE)	25.2	12%	40%
San Francisco (CAISO: PG&E)	22.4	13%	37%
Charlotte-Greenville (all of Duke Carolinas)	21.3	14%	31%
Indianapolis (MISO: LRZ 6)	17.0	18%	54%
St. Louis (MISO: Ameren Missouri and Illinois)	16.3	18%	7%
Phoenix (APS, SRP)	15.2	20%	56%
Birmingham (Alabama Power)	13.6	22%	28%
Detroit (MISO: DTE)	11.7	26%	45%
Cincinnati (PJM: DEOK, DAY)	8.6	35%	53%
New Orleans (MISO: Entergy New Orleans and Louisiana)	7.1	42%	74%
Seattle (Puget Sound, Seattle City)	7.1	42%	31%
Las Vegas (Nevada Power)	6.6	45%	53%
Little Rock (MISO: Entergy Arkansas)	6.5	46%	34%
Salt Lake City (PACE-UT)	5.6	54%	70%
Jackson (Entergy Mississippi, Mississippi Power)	5.6	54%	29%
Portland (PGE)	4.3	70%	37%
Boise (Idaho Power)	3.6	83%	41%

Source for 2022 peak data: Hitachi Energy 2023.

Note: Expected load growth is taken from the NTP Study (DOE, forthcoming), which uses load forecasts that were reviewed by state officials. Growth numbers shown here are from high-load-growth scenarios and are informational only; they were not used in the IREZ methodology.

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4 Matching IREZs and Load Centers

NREL's reV model has a linear routing capability that identifies the least-cost transmission path between two points (Lopez 2024). It accounts for areas where transmission siting is prohibited or difficult (national parks, high-density urban areas), and it includes construction cost adders for various types of terrain. It also accounts for right-of-way land costs. We used this capability in reV to match each load center with the IREZ that could provide the lowest-cost renewable energy with the lowest transmission cost. Figure 8 shows a map of the IREZ-to-load corridors.

Note that reV *does not* provide recommended routing for new lines. Its purpose is to provide a more accurate estimate of transmission line miles for the economic analysis described in the next section. States have authority over transmission siting in most cases.

The first step in the matching task was to find each load center's best-fit IREZ, where "best-fit" meant the lowest marginal LCOE in the connecting IREZ and the least-cost HVDC distance. The second step was to test strategic combinations of load centers that would be served by the same IREZ corridor. For example, the best direct fit for Charlotte, North Carolina was the Kansas IREZ, across a distance of 1,011 line miles. A corridor from Kansas to Charlotte by way of Nashville, Tennessee, however, could allow two lines to share a common ROW for about two-thirds of that distance, with the potential for transmission cost savings.

We also tested optimal matching under a range of values for congestion costs in ERCOT, as explained in Section 2.2 above. These sensitivity tests revealed economic competition between the ERCOT and Oklahoma IREZs for providing wind power to load centers in the Southeast. As a result, our analysis suggests that Little Rock and Montgomery could be served by either Oklahoma or ERCOT, with the least-cost source determined by future congestion costs in ERCOT.

Although the algorithm did not prohibit corridors across the east-west interconnection seam, none was chosen. The cost per mile of an HVDC line created an economic preference for IREZs that were relatively close to load centers, and no cross-seam corridor emerged. The matching analysis produced three focus areas: the Western Interconnection; the Southeast; and the remainder of the Eastern Interconnection.

Offshore wind is the subject of several other studies using analytical methods different from those used here. IREZ renewables and offshore wind both can be bulk sources of clean energy resources for certain load centers. As a convenience for the reader, Figure 8 includes offshore wind areas to illustrate where they and IREZ resources might both contribute to a load center's clean energy resource mix.

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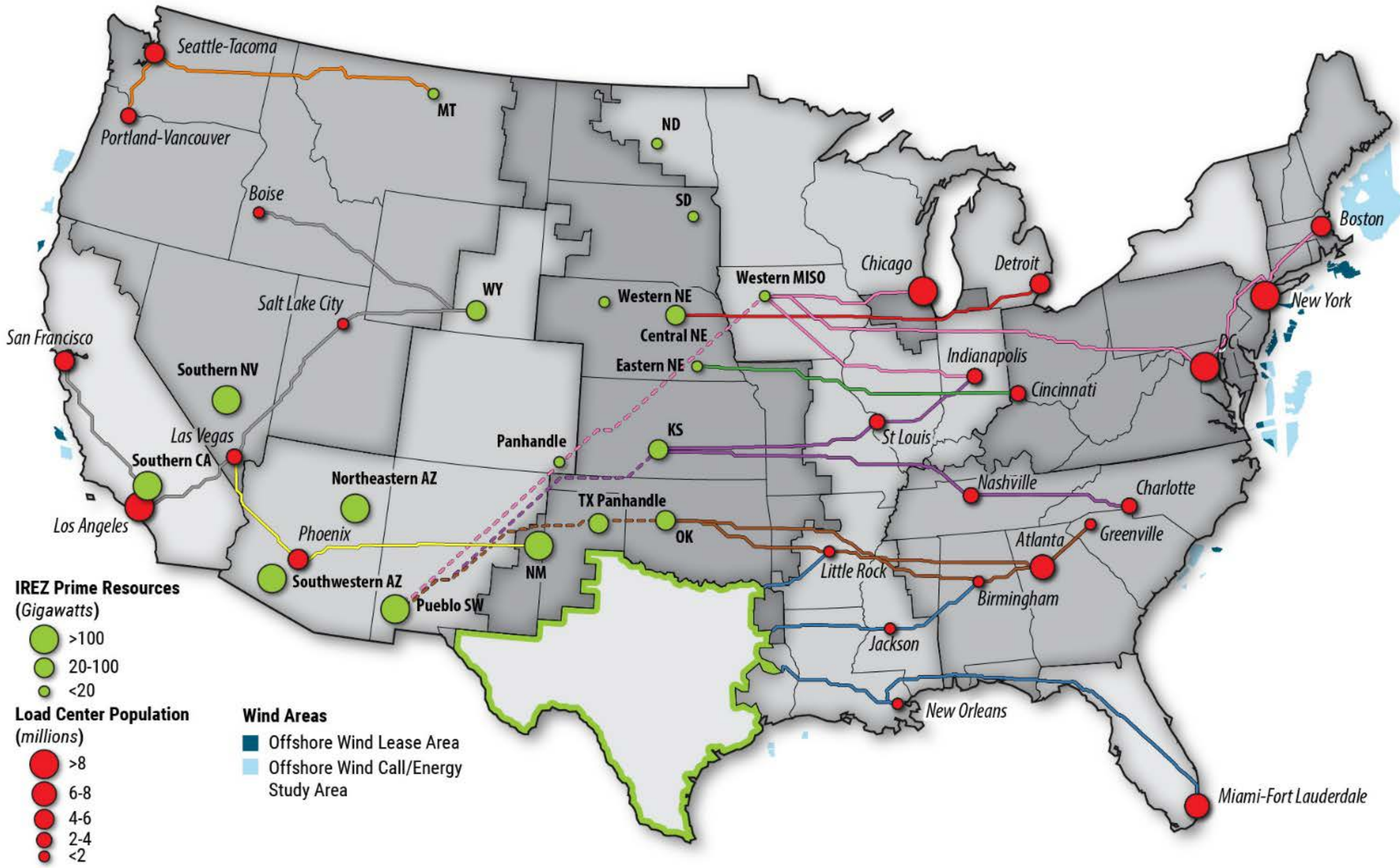

Note: Corridors shown on the map represent least-cost distances based on available data. They are not recommendations for specific transmission routes. Colors identify corridors from a unique IREZ; dashed lines indicate connections between a primarily wind IREZ and a solar IREZ in the Southwest. IREZs on this map shown with no connection to a load center may provide additional supply options. Shaded areas indicate transmission planning regions used in Phase 1 of the IREZ analysis. (Hurlbut et al. 2022). See Sections 1.7 and 2.2 for an explanation of why ERCOT is depicted as a region rather than a hub. Offshore wind areas are shown to illustrate where they and IREZ resources might both contribute to a load center's clean energy resource mix.

Figure 8. IREZ corridors

Table 3. Best Matches Between Load Centers and IREZs

Metropolitan area [a]	Best IREZ match	IREZ marginal LCOE
Western Interconnection		
Seattle, WA [16%] Portland, OR [29%]	Montana	Best 15 GW: $20.90/MWh Best 30 GW: $21.70/MWh
Salt Lake City, UT [31%] Las Vegas, NV [34%] Los Angeles, CA [7%] San Francisco, CA [9%]	Wyoming	Best 15 GW: $18.80/MWh Best 30 GW: $19.70/MWh Best 45 GW: $20.30/MWh Best 60 GW: $20.80/MWh
Boise, ID [73%]		
Phoenix, AZ [14%] Las Vegas, NV [34%]	New Mexico	Best 15 GW: $19.50/MWh Best 30 GW: $20.00/MWh
Eastern Interconnection (Midwest, Northeast)		
New York, NY [5%] Washington, D.C. [7%] Boston, MA [8%]	Iowa	Best 15 GW: $20.10/MWh Best 30 GW: $20.50/MWh Best 45 GW: $20.80/MWh Best 60 GW: $21.10/MWh
Chicago, IL/Milwaukee, WI [9%]		
Indianapolis, IN [25%]		
Nashville, TN [11%] Charlotte, NC [16%]	Kansas	Best 15 GW: $19.30/MWh Best 30 GW: $19.60/MWh Best 45 GW: $20.00/MWh
St Louis, MO/KS [21%] Indianapolis, IN [25%]		
Detroit, MI [11%]	Central Nebraska	Best 15 GW: $20.00/MWh
Cincinnati, OH [28%]	Eastern Nebraska	Best 15 GW: $19.70/MWh
ERCOT and Eastern Interconnection (Southeast)		
New Orleans, LA [13%] Miami, FL [13%]	ERCOT[b]	Best 15 GW: $18.45/MWh Best 30 GW: $18.84/MWh Best 45 GW: $19.09/MWh Best 60 GW: $19.37/MWh
Birmingham, AL [26%] Jackson, MS [33%]		
Little Rock, AR [33%]		
Atlanta, GA [8%] Greenville, SC [42%] Little Rock, AR [33%] Birmingham, AL [26%]	Oklahoma	Best 15 GW: $19.00/MWh Best 30 GW: $19.70/MWh Best 45 GW: $20.00/MWh Best 60 GW: $20.70/MWh

[a] Number in [brackets] is 3 GW as a percentage of the load center area's 2022 peak demand.
[b] Marginal LCOE for ERCOT does not includes cost of using the ISO AC transmission network, which we estimate in the economic analysis as ranging from $2 to $5/MWh.

4.1 Caveats on Interpreting the Corridors

Figure 8 should not be construed as recommendations for transmission routing. The corridors shown represent nothing more than the least-cost pathways between a load center and its IREZ

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based on data available for the analysis. Routing a real project would take into account site-specific factors that are outside the data examined here but would be considered in a regulatory proceeding. The analytical purpose of the corridor analysis is to obtain a plausible estimate of transmission line miles for the economic analysis.

In addition, the map is not a consolidated multicorridor plan. Each IREZ corridor shown is an individual project whose development does not depend on the development of any other corridor.

The groupings in Table 3 indicate the potential for combining ROWs to serve multiple load centers and reducing transmission project costs. The economic analysis in Section 5 does not quantify the potential savings of sharing an ROW, however. We calculate transmission costs for each load center as though it were the only destination for a 600-kV line, meaning that two separately dedicated DC lines might share some ROW. This is a conservative assumption economically, because in reality combining load centers could enable more cost-effective transmission alternatives, as explained in Section 7.2.

4.2 Western Interconnection

One interesting characteristic of the IREZ corridors in the Western Interconnection is that most of them align with transmission projects that are already under construction or in advanced planning. These project, in turn, align with two of the largest zones identified in the Western Renewable Energy Zone study that NREL conducted for the Western Governors' Association in 2009 (Pletka 2009, WGA 2009).

- The corridors from Wyoming to California overlap significantly with the TransWest Express HVDC project.
- The corridor from Wyoming to Salt Lake City overlaps significantly with PacifiCorp's Gateway West and Gateway South projects. Gateway West would also increase the flow of power from Wyoming to Boise.
- The corridor from New Mexico to Phoenix aligns significantly with the SunZia project.

In addition, Xcel Energy's proposed Colorado Power Pathway draws on resource areas in the four-state Panhandle IREZ (comprising Colorado, New Mexico, Kansas, and Texas) for delivery to the Denver metropolitan area. (Because this project is not interregional, however, we do not include it in this analysis.)

The corridors in the Northwest connected the Montana IREZ with Seattle and Portland. These paths overlap with existing 500-kV HVDC lines that carry power from the Colstrip Power Station in eastern Montana. The Colstrip line carries power to a point in western Montana, and from there the power flows to Washington and Oregon on 500-kV lines operated by the Bonneville Power Administration (BPA).

4.3 Eastern Interconnection: Midwest, Northeast

Most national transmission studies including the NTP Study identify the potential need for significantly more transfer capability from wind belt states such as Iowa, Kansas, and Nebraska

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to load centers in PJM and eastern MISO. Several IREZ corridors identified in this analysis align with these national results.

Proposed projects that align with IREZ results include SOO Green (Iowa to Chicago and Milwaukee) and Grainbelt Express (Kansas to St. Louis and Indianapolis).

4.4 ERCOT and Eastern Interconnection: Southeast

With the exceptions of Nashville and Charlotte, all load centers in the Southeast transmission planning region economically align with either ERCOT or the Oklahoma IREZ. In the southern MISO region, Little Rock could be served by ERCOT or the Oklahoma IREZ.

Because of the high degree of uncertainty related to estimates of future congestion costs, we tested a range of network cost adders to determine the sensitivity of IREZ matching to ERCOT congestion costs. The high end of this range represents 2022 pricing and supply conditions, while lower values represent lower natural gas prices and lower congestion costs.

The effect of changing the adder was limited to IREZ corridors in the Southeast. As the adder increased, load centers' economic affinity shifted incrementally from ERCOT to the Oklahoma IREZ. The main factor causing the shifts was the trade-off between the modeled cost of transmission congestion in ERCOT and the additional transmission distance from the Oklahoma IREZ to a load center.

- As the adder increased from $2 to $3 per MWh, the best IREZ match for **Greenville** shifted from ERCOT to Oklahoma.
- As the adder increased from $3 to $4 per MWh, the best IREZ match for **Atlanta** shifted from ERCOT to Oklahoma.
- As the adder increased from $4 to $5 per MWh, the best IREZ match for **Little Rock** and **Miami** shifted from ERCOT to Oklahoma.
- As the adder increased from $5 to $6 per MWh, the best IREZ match for **Birmingham** shifted from ERCOT to Oklahoma, and the best match for **Jackson** shifted from ERCOT to the Texas Panhandle (which is not in ERCOT). ERCOT remained the best match for **New Orleans**.
- Increasing the adder from $6 to $7 had no effect on IREZ matching.

We selected $2 to $5 per MWh as the test range for ERCOT network costs in the IREZ analysis based on historical prices and the authors' understanding of the ERCOT market, recognizing that unforeseen disturbances could push network costs in a given year beyond $5 per MWh.

4.5 Combining Solar and Wind IREZs

We added three targeted scenarios to test the benefit of combining a solar and wind IREZ on the same corridor. The hypothesis was that resource diversity—specifically prime-quality wind combined with prime-quality solar—would have more economic value on a DC transmission corridor than either resource alone. Although all of the wind IREZs had solar in their supply

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curves that could be delivered to load, the marginal LCOE of solar in these zones tended to be several dollars per MWh higher than the $24 per MWh benchmark used to define solar IREZs in the U.S. Southwest.

Figure 9 shows the supply curves for the five solar IREZs identified in the analysis. We selected the Pueblo Southwest IREZ for testing because it had the greatest potential for both low energy costs and proximity to load centers in the Eastern Interconnection.

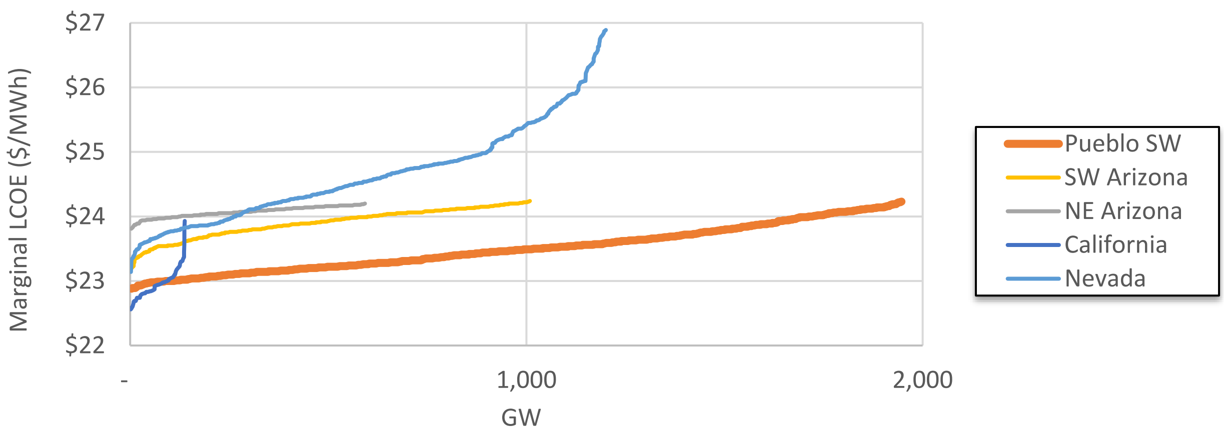

Figure 9. Supply curves of solar IREZs

The solar scenarios involved linking the Pueblo Southwest IREZ (orange circle in Figure 10) with the three most-used wind IREZs: Oklahoma, Kansas, and Iowa (blue circles in Figure 10). The selected load centers for each of these wind IREZs were Atlanta, Charlotte, and Washington, D.C. (black circles in in Figure 10).

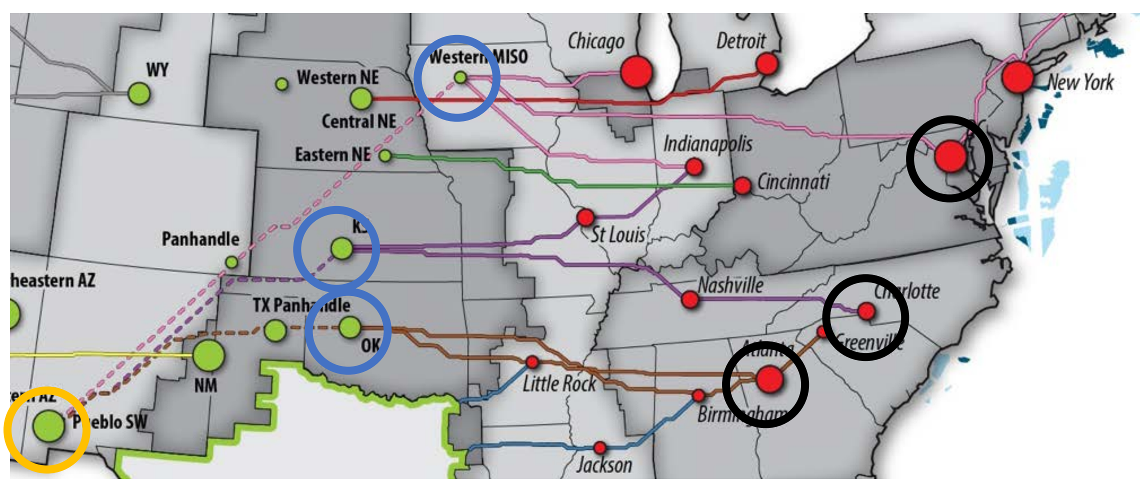

Figure 10. Pathways from the Pueblo Southwest Solar IREZ to three test destinations

NREL's REopt platform provided analytics to identify the optimal mix of solar, wind, and on-site battery storage.[13] As with the other simulations, we assumed that the entire transmission corridor had a source-to-sink transfer capability of 3 GW. Energy from PV plants entered the

[13] See https://reopt.nrel.gov for more information on the REopt platform.

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corridor at the Pueblo Southwest IREZ hub, and energy from wind plants entered at the associated intermediate IREZ hub.

We then combined the solar and wind production profiles (with the optimal amount of on-site battery storage) to match with the hourly cost of electricity in the target load center.

Table 4. Results of Solar IREZ Corridor Optimizations

	GW solar	GW wind	TWh delivered to load
Pueblo SW to Oklahoma to Atlanta	2.7	3.3	19.3
Pueblo SW to Kansas to Charlotte	3.7	3.3	19.7
Pueblo SW to Iowa to Washington, D.C.	3.9	3.1	19.3

Table 4 shows the optimization results. The main constraint was the 3 GW of transmission capability on the 600-kV line from the wind IREZ to the load center. Utilization of this leg increased because of the blended wind and solar energy. On the other hand, a 600-kV line from the Pueblo Southwest IREZ to the wind IREZ was never used to its full capacity. One reason was that if generation had to be curtailed, the optimization would tend to reduce the resource that had the higher LCOE. Based on this observation, we reduced the size of the transmission line between the solar and wind IREZs from 600 kV to 500 kV, which reduced the cost of this leg by 6%–7%. Line losses are slightly higher with a 500-kV HVDC line but not enough to affect the amount of solar energy delivered to load.

4.6 IREZs and Tribal Lands

Some of the resource areas included in the Oklahoma, Montana, and Pueblo Southwest IREZs are tribal lands. Whether these sites within the IREZ would be available for development would be a matter of tribal policy. However, the potential for future developer interest in these IREZs could inform tribal policies about site access, employment requirements, tribal revenues, and other project development issues applicable to their land.

The Oklahoma IREZ is in western Oklahoma and includes the Caddo-Wichita-Delaware, Cheyenne and Arapaho, Chickasaw, and Kiowa-Comanche-Apache-Fort Sill Apache tribal statistical areas. This IREZ was a strong match for load centers in the Southeast.

The Montana IREZ includes significant wind resource areas on the Blackfeet Reservation. New transmission carrying wind from this IREZ could pass across the Flathead Reservation about 70 miles to the southwest. Western Montana and northern Idaho already have existing 500-kV transmission owned and operated by BPA. Therefore, transmission alternatives might exist that are superior to the standard 600-kV HVDC assumption applied in this analysis, and some of those alternatives could involve tribal land.

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The expansive Pueblo Southwest solar IREZ includes parts of the San Carlos and Tohono O'odham reservations in southern Arizona. To date, utility-scale solar development has largely missed these reservations, even though it has been robust elsewhere in southern Arizona.

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5 Economic Analysis

We focus the analysis of IREZ outcomes on two types of value: savings in the cost of producing energy and savings in the cost of resource adequacy. However, many inputs to these estimations are clothed in great uncertainty when looking to the future when an IREZ line would be energized. In regulatory proceedings such as integrated resource plans, economic assumptions about future fuel prices, load growth, and other external factors are subject to review by stakeholders, with the regulator ultimately sanctioning the assumptions that most reasonably capture future uncertainty.

Our approach in this analysis is to unpack the determinants of economic value so that state decisionmakers and stakeholders can develop a reasoned consensus on future uncertainty. Our quantitative comparisons focus on current actual data with qualitative descriptions of factors likely to affect future values.

The question framing the economic analysis is: *Are the annualized benefits of IREZ resources less or more than the annual revenue requirement (ARR) of IREZ transmission?*

Only transmission ARR and energy cost savings are monetized in this analysis. We report resource adequacy results as changes in expected unserved energy, but without assigning a dollar value. Because no agreed-upon metric for it currently exists, we set aside the value of additional resilience. Quantifying resilience benefits is an emerging area of research, and we cannot resolve its complex issues in this study. The simplified approach here is to ask whether savings in energy costs and resource adequacy are sufficient to carry the economic weight of the transmission costs.

5.1 Transmission Costs

The transmission assumptions that form the foundation of the IREZ economic analysis are for a 600-kV HVDC transmission line from the IREZ to the load center. This standardizes the estimates of IREZ transmission costs and, consequently, the benefit-to-cost ratios explained in the next section.

Black & Veatch and Energy+Environmental Economics Inc. developed a transmission cost tool for the Western Electricity Coordinating Council (WECC) in 2014, and we use the 2019 update of that tool to standardize our transmission cost assumptions (WECC 2019). We also applied an inflation adjustment to bring 2019 prices to their 2022 equivalents.

We converted total project costs to an ARR by applying a depreciated capital recovery factor (DCRF). The DCRF accounts for the cost of taxes including deductions depreciation in the normal capital recovery factor, which annualizes the cost of capital investment. The DCRF used a 5% real discount rate and a 40-year life for the transmission.

Table 5 lists the key transmission cost assumptions used in the economic analysis. For comparison, the table also shows the cost of the same items for a double-circuit 500-kV AC line, which has about the same transfer capability as a 600-kV HVDC line. Actual costs depend on the specific system needs (e.g., substation transformer size), terrain, and land use. Taking these into account, the WECC cost calculator indicates that a 500-kV AC line tends to be more cost-

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effective for distances up to 300 miles (for difficult terrain) and 600 miles (for easy terrain), with 600 kV DC being more cost-effective over longer distances.

Table 5. Key Transmission Cost Assumptions

	600 kV HVDC	500 kV HVDC	500 kV HVAC (double circuit)
Transfer capacity	3,000 MW	3,000 MW	3,000 MW
Cost per line mile			
Flat scrub, farmland, barren land	$2.6 million	$2.5 million	$4.9 million
Forested	$5.8 million	$5.6 million	$11.1 million
Right-of-way (acres per mile)	27.3	24.2	30.3
Substation cost	$23 million	$23 million	$23 million
DC converter	$692 million	$629 million	n/a
Losses per 100 miles	11.5 MW	16.5 MW	21.6 MW
Depreciated capital recovery factor	0.06981	0.06981	

Source: WECC 2019. 2018 costs multiplied by 1.28 to approximate 2022 costs.

As explained in Section 4.5 above, transmission from the Pueblo Southwest solar IREZ to the three wind IREZs in Oklahoma, Kansas, and Iowa was never fully loaded in the REopt optimizations. For the economic analysis, we have reduced the assumed size of this transmission leg from 600 kV to 500 kV. This reduced the cost of this segment by 6%–7%. It also increased line losses, but this had no effect on the results because this segment was not utilized fully.

5.2 Savings in Annual Energy Costs

The difference between the LCOE of IREZ resources and the load center's cost of procuring energy constitutes savings in energy costs. We assume that LCOE—and consequently the cost paid by load—is a constant dollars-per-megawatt-hour value, similar to the structure of many wind and solar power purchase agreements.

Delivery of IREZ energy would replace generic energy in the load center's supply mix. The cost of generic energy is time-sensitive, based on the marginal cost of energy for the hour when energy is delivered to load. However, the load centers in this analysis differ significantly with respect to data on energy production costs. Here we apply the following hierarchy of pricing methodologies:

1. **Locational marginal prices** (LMPs) capture the hourly location-specific cost of energy in RTOs and ISOs. For this analysis, we use hourly day-ahead LMPs for 2022 for load centers in an RTO or ISO.
2. **Interchange LMPs** are available for utilities in the West that are not in an RTO or ISO but participate in CAISO's Western Energy Imbalance Market (WEIM). Interchange LMPs are also available for certain non-RTO areas in the Eastern Interconnection. Although these LMPs do not represent the local utility's total cost of generation, they are reasonable representations of the value of a utility's surplus energy for a given operating hour. A

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drawback of using interchange LMPs is that they disproportionately reflect the marginal cost of systemwide energy *in the RTO* rather than in the non-RTO utility. They also do not account for low-cost generation that the utility might choose to retain for its own local load and not offer in the RTO/ISO market.[14]

3. Neither Atlanta nor Miami are near an RTO or ISO, therefore they have no interchange node. Instead, we examined **energy cost riders** included in Georgia Power and Florida Power & Light customer electricity bills. These riders capture the utility's cost of fuel and of wholesale power purchased from other providers, which the utility passes on to customers on a per-megawatt-hour basis without additional markup. They distinguish between peak and off-peak use and often vary seasonally, even though they lack the granularity of hourly LMPs. In this analysis, we use riders for large commercial and industrial customers.

The difference between the IREZ resources' LCOE and the time-sensitive cost of the energy replaced is the hourly savings in energy costs. IREZ wind and solar are variable resources, and the hourly production from those resources affects the magnitude of savings in any given hour. The annual energy savings is the sum of estimated savings for each hour of the year. Mathematically,

$$annual\ energy\ cost\ savings = \sum_{h=1}^{8,760} (C_h - LCOE) * MWh_h$$

where C_h is the cost of energy for customers in the load center for hour *h*, *LCOE* is the cost of IREZ resources, and MWh_h is the amount of energy delivered from the IREZ during hour *h*. Table 6 summarizes net energy savings for each IREZ corridor.

[14] The authors decided that for the purpose of this analysis, the benefit of hourly cost granularity outweighs the shortcomings of interchange LMPs, especially in the absence of other alternatives. If states were to launch a more detailed follow-on analysis of an IREZ corridor, we recommend that they require their non-RTO utilities to provide data comparable to LMPs that more accurately reflect the utilities' hourly cost of energy.

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Table 6. Summary of IREZ Economic Attributes

IREZ	Destination	Annual energy cost savings ($millions)	Annual revenue requirement for HVDC line ($millions)	Ratio of energy cost savings to HVDC cost
Eastern Interconnection and ERCOT				
Iowa	Washington	$740	$296	2.50
	New York	$858	$323	2.66
	Boston	$886	$344	2.58
	Chicago/Milwaukee	$531	$186	2.85
	Indianapolis	$557	$215	2.59
Kansas	St. Louis	$603	$212	2.85
	Indianapolis	$595	$215	2.77
	Nashville	$610	$248	2.46
	Charlotte	$626	$291	2.15
Nebraska	Cincinnati	$692	$244	2.84
	Detroit	$650	$264	2.46
Oklahoma	Atlanta	$338	$264	1.28
	Greenville	$654	$276	2.37
	Little Rock	$581	$186	3.12
	Birmingham	$608	$306	1.99
ERCOT	Jackson	$515–$561	$168	3.07-3.34
	New Orleans	$547–$593	$174	3.14-3.41
	Miami	$533–$578	$389	1.37-1.49
	Little Rock	$508–$561	$153	3.32-3.62
	Birmingham	$541–$586	$201	2.69-2.92
Western Interconnection				
Wyoming	Salt Lake City	$1,081	$172	6.28
	Boise	$1,079	$213	5.07
	Las Vegas	$1,045	$247	4.23
	Los Angeles	$1,322	$281	4.70
	San Francisco	$1,376	$351	3.92
New Mexico	Phoenix	$963	$210	4.59
	Las Vegas	$966	$247	3.91
Montana	Seattle	$940	$235	4.00
	Portland	$939	$306	3.07

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IREZ	Destination	Annual energy cost savings ($millions)	Annual revenue requirement for HVDC line ($millions)	Ratio of energy cost savings to HVDC cost
Cross-Interconnect Solar from Pueblo Southwest IREZ				
Pueblo SW, Oklahoma	Atlanta	$405	$421	0.98
Pueblo SW, Kansas	Charlotte	$849	$456	1.86
Pueblo SW, Iowa	Washington	$994	$521	1.91

Table 6 also summarizes the ratio of annual energy savings costs to the annual revenue requirement of IREZ transmission. This provides a partial measure of benefits (limited to the magnitude of energy cost savings compared to the additional capital cost of IREZ transmission). It does not account for resource adequacy or any externality, nor does it account for how energy or capital costs might change in the future.

Each of the three solar-plus-wind scenarios result in significantly greater energy cost savings than their corresponding wind-only scenarios. Transmission costs are also higher, however, causing the benefit/cost ratios to be lower.

5.3 Improvements in Resource Adequacy

Resource adequacy refers to the amount of resources that the system needs to have on hand to ensure reliable delivery of electricity at all times. In the past, resource adequacy was a function of annual peak demand and the amount of firm capacity available during the peak. This simple approach has become less useful with the growth of variable resources such as wind and solar and the growth of demand response resources.

This analysis relies on expected unserved energy (EUE) as a key metric for resource adequacy. Unserved energy can occur any time when the bulk power system cannot meet demand because total resources are insufficient, generators cannot ramp quickly enough, too many generators are locked behind transmission constraints, or other reasons.

NREL's Probabilistic Resource Adequacy Suite (PRAS) measures EUE for a system by applying random outages to the network, repeated and normalized over many scenarios within a Monte Carlo framework. (This analysis used 500 random outage cases.) The results indicate the expected magnitude of lost load during the year with the given resource set: normalized EUE (nEUE), measured as a percentage of demand that goes unserved in the event of an outage. For example, nEUE of 0.001% means that for every terawatt-hour of demand during the year, 10 MWh would not be served by the given resources if an unplanned outage were to occur.[15] Higher nEUE means the loss of a plant or transmission line would cause more customers to go without electricity for longer periods of time.

[15] nEUE may also be expressed as parts per million, or PPM. An nEUE of 0.001% indicates 10 PPM of demand is unserved.

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We applied the PRAS analysis to a capacity expansion scenario for 2025 simulated in the NTP Study for the 48 contiguous U.S. states (CONUS). The capacity expansion model includes a constraint that keeps nEUE below 0.001% in the optimized solution set. The first step in the IREZ analysis was to artificially increase demand in the target load center's planning region to the point that nEUE was approximately 0.001%. We then added 3 GW of the best locally available renewable resources and measured the improvement in nEUE.[16] After that, we replaced the 3 GW of local renewables with 3 GW of IREZ renewables (accounting for transmission loses at 0.1 MW per mile) and measured nEUE again. The difference between nEUE outcomes indicates which resource contributes more to resource adequacy.

Table 7 shows the results of the PRAS analysis for each pairing of IREZs and load centers. Lower nEUE scores indicate a better contribution to resource adequacy in the target load center.

We do not monetize the value of changes in EUE here. The market value of an improvement in EUE would depend on the value of lost load in the delivery area, and on whether the area was starting from a position of surplus capacity or capacity shortage. If an area already had excess capacity such that the loss of any generator would not create EUE, the market value of additional resource adequacy from any source would be low. The monetary value of resource adequacy is a task for follow-on studies that focus on a specific corridor.

[16] Phase 1 of the IREZ analysis (Hurlbut et al. 2022) identified preliminary zones for each transmission planning region, most of which were eliminated in this phase because they failed to meet the criteria in Section 2. For the resource adequacy analysis, we used the lowest-LCOE resources in the preliminary zone nearest to a load center as a proxy for the load center's best local renewable resources.

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Table 7. Summary of IREZ Resource Adequacy Impacts

IREZ	Destination	Normalized EUE with 3 GW New Renewables		IREZ Renewables Contribution to nEUE[a]
		IREZ	Local	
Eastern Interconnection and ERCOT				
Iowa	Washington	0.00052%	0.00013%	worse
	New York	0.00035%	0.00033%	similar
	Boston	0.00031%	0.00026%	similar
	Chicago/Milwaukee	0.00017%	0.00007%	worse
	Indianapolis	0.00019%	0.00007%	worse
Kansas	St. Louis	0.00024%	0.00053%	better
	Indianapolis	0.00026%	0.00007%	similar
	Nashville	0.00020%	0.00047%	better
	Charlotte	0.00005%	0.00024%	better
Nebraska	Cincinnati	0.00011%	0.00036%	better
	Detroit	0.00033%	0.00037%	similar
Oklahoma	Atlanta	0.00052%	0.00056%	similar
	Greenville	0.00010%	0.00010%	similar
	Little Rock	0.00022%	0.00043%	better
	Birmingham	0.00031%	0.00053%	better
ERCOT	Jackson	0.00034%	0.00068%	better
	New Orleans	0.00036%	0.00050%	better
	Miami	0.00034%	0.00031%	similar
	Little Rock	0.00014%	0.00043%	better
	Birmingham	0.00025%	0.00054%	better
Western Interconnection				
Wyoming	Salt Lake City	0.00005%	0.00060%	much better
	Boise	0.00002%	0.00002%	similar
	Las Vegas	0.00036%	0.00071%	better
	Los Angeles	0.00056%	0.00089%	better
	San Francisco	0.00026%	0.00097%	much better
New Mexico	Phoenix	0.00022%	0.00079%	much better
	Las Vegas	0.00019%	0.00071%	much better
Montana	Seattle	0.00001%	0.00010%	better
	Portland	0.00022%	0.00054%	better

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IREZ	Destination	Normalized EUE with 3 GW New Renewables		IREZ Renewables Contribution to nEUE[a]
		IREZ	Local	
Cross-Seam Solar from Pueblo Southwest IREZ				
Pueblo SW, Oklahoma	Atlanta	0.00014%	0.00056%	much better
Pueblo SW, Kansas	Charlotte	0.00003%	0.00024%	better
Pueblo SW, Iowa	Washington	0.00002%	0.00013%	better

[a] Descriptions are based on the contribution of 3 GW of renewable resources to resource adequacy when the initial EUE in the load center is 0.001%. “Much better” means that IREZ renewables reduce EUE by at least 0.0005 percentage points more than local renewables do, “better” means the difference is between 0.0001 to 0.0005 percentage points, “similar” is the difference is between 0.0001 and -0.0001 percentage points, and “worse” means that the difference is below -0.0001 percentage points.

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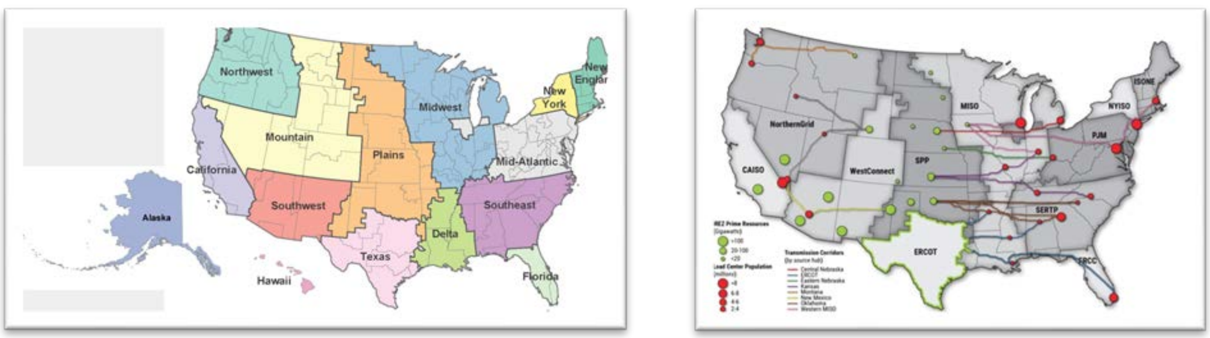
6 Alignment of IREZ Corridors With Other DOE Studies

The IREZ analysis was conducted contemporaneously with two other national studies that the U.S. Department of Energy (DOE) conducted under the aegis of the Infrastructure Investment and Jobs Act: the NTP Study and the National Transmission Needs Study (“Needs Study”). The NTP Study uses a CONUS-wide capacity expansion model to simulate the effects of different transmission builds on the pace and cost of decarbonizing the grid (DOE forthcoming). The Needs Study is a national assessment of current and future transmission needs driven by capacity constraints and congestion; access to cost-effective generation, reliability, resilience; and changes in electricity demand (DOE 2023).

The IREZ analysis applies a narrower focus on specific potential interregional transmission paths. When juxtaposed against the Needs Study or the NTP Study, the IREZ analysis asks: *Does an HVDC transmission line from a specific renewable energy zone to a specific load center plausibly fit part of the additional transfer capacity demand revealed in the Needs Study or the NTP Study between the two regions?*



Needs Study IREZ Study

Figure 11. Regions in the Needs Study and in the IREZ Study

6.1 The National Transmission Needs Study

The Needs Study, released in October 2023, fulfills a directive to DOE under the Federal Power Act to “conduct a study of electric transmission capacity constraints and congestion” every 3 years.[17] DOE’s goal was to synthesize the most recent comprehensive studies so that industry and the public might explore the best possible solutions for addressing transmission issues in a timely manner.

The Needs Study broke the country into 15 analytical regions (including Alaska and Hawaii) and examined needs both within and between regions. Figure 11 shows these regions side-by-side with those used in both the IREZ and NTP studies. For its analysis of future interregional transmission, the Needs Study relied primarily on a meta-analysis of six recent studies that applied CONUS-wide capacity expansion modeling. These studies, all released after 2020, included approximately 300 scenarios.

[17] Federal Power Act Section 216(a)(1), 16 U.S.C. 824p(a)(1).

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Throughout, the Needs Study assumes that scenarios that model moderate load growth and high clean energy growth represent “a likely power sector future given recently enacted laws.”[18] Another set of scenarios assume both high clean energy growth and high load growth. Here, we use the median values of these two scenario groups to bookend Needs Study findings.

6.1.1 Eastern Interconnection: Midwest, Northeast

Most of the IREZ corridors originating in Iowa, Nebraska, and Kansas are consistent with Needs Study findings. The demand for new transfer capacity estimated in the Needs Study is greatest between the study’s Midwest and the Mid-Atlantic regions: 34 GW (moderate load growth, high clean energy growth scenarios) to 103 GW (high load growth, high clean energy growth scenarios) by 2035 (see Figure 12). It also identified a need for an additional 21 GW to 88 GW between the Plains and Midwest regions.

These projections suggest a robust demand for a 3-GW HVDC connection, such as the one analyzed in the IREZ study for the Iowa to Washington, D.C. corridor. The results could also encompass corridors from other IREZs in the Plains and Midwest to load centers in the Midwest and Mid-Atlantic.[19]

The Needs Study anticipates a demand for new transfer capacity between the Mid-Atlantic and New York to New England that is more moderate than transfers from the Midwest to the Mid-Atlantic: 2 GW to 8 GW from the Mid-Atlantic to New York and 5 GW to 17 GW between New York and New England. The standard 3 GW tested in the IREZ analysis would fit with these estimates but with a much smaller margin than suggested by the Needs Study’s estimates for the Plains to the Mid-Atlantic.

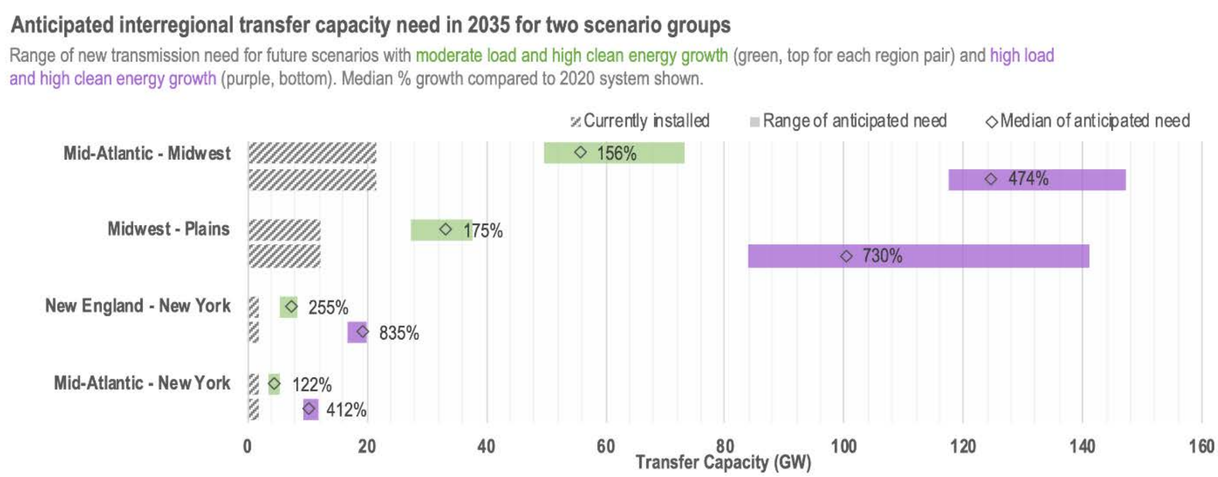

Chart adapted from Needs Study, Executive Summary (DOE 2023)

Figure 12. Needs Study findings aligning with Plains to Northeast IREZ corridors

[18] Needs Study p. 125.

[19] The Needs Study did not separate flows that would originate in one region, pass through a neighboring region, and serve load in a third region. We assume here that such flows could be implied by daisy-chaining results, in this case from the Plains to the Midwest and from the Midwest to the Mid-Atlantic.

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6.1.2 Eastern Interconnection (Southeast) and ERCOT

The ERCOT and Oklahoma IREZs coincide with the Needs Study's Plains and Texas (ERCOT) regions, with destination loads in the study's Southeast, Delta, and Florida regions. Indeed, one of the most robust corridors identified in the IREZ study is from the wind-rich Oklahoma IREZ (Plains Region) to load in Atlanta (Southeast Region). Findings from the Needs Study suggest a two-stage path between the Plains to the Southeast regions: 20 GW to 48 GW of new transfer capacity between the Plains and Delta regions and 5 GW to 34 GW between the Delta and Southeast regions (see Figure 13). The 3-GW HVDC transmission path from the Oklahoma IREZ to Atlanta tested in the IREZ analysis is reasonably consistent with pairing these two between-region increases. The projections in the Needs Study could also encompass connections from the Oklahoma IREZ to Alabama, Arkansas, and South Carolina.

A key difference in the Needs Study is the absence of new interregional transfers between its Texas (ERCOT) and Delta regions. Only one of the reports included in the Needs Study's meta-analysis considered new transfer capacity between Texas and the Delta region; therefore, the authors of the Needs Study excluded this connection from the main analysis because of the small sample size.[20] In contrast to the Needs Study, the IREZ analysis and the NTP Study both identify a potential demand for new transfer capacity from ERCOT to Louisiana and southern Mississippi and thence to Florida. Besides these simulated results, the proposed Southern Spirit transmission project would provide about 3 GW of capacity from eastern ERCOT to western Mississippi (FERC 2014).

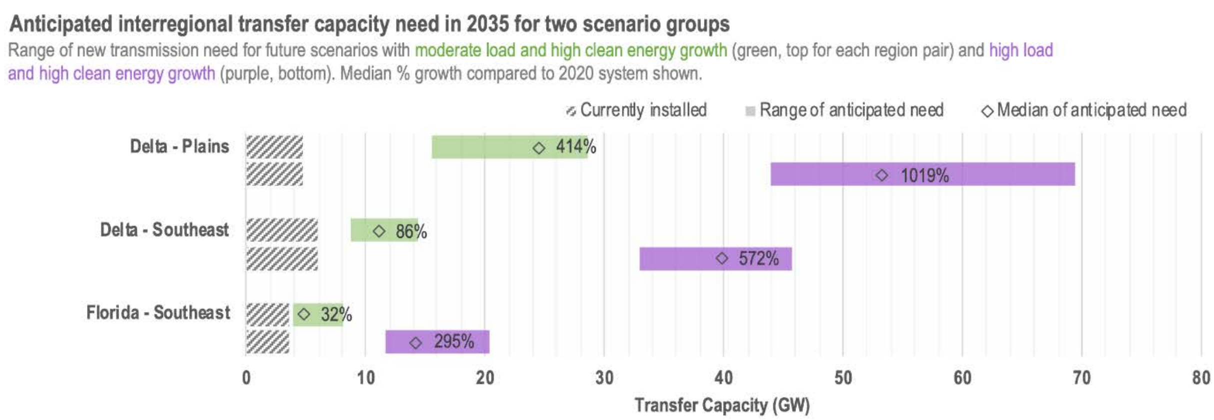

Chart adapted from Needs Study, Executive Summary (DOE 2023)

Figure 13. Needs Study findings aligning with Plains to Southeast IREZ corridors

[20] Needs Study, p. 131. As the current report discusses in Section 1.7, jurisdictional differences limit the ability to flow power between ERCOT and the rest of the United States. The one analysis included in the Needs Study that considered ERCOT flows found demand for 48.3 GW to 106.7 GW of transfer capacity between ERCOT and the Delta region (moderate load growth/high clean energy growth scenarios and high load growth/high clean energy growth scenarios).

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6.1.3 Western Interconnection

Most of the pathways identified in the IREZ analysis for the West align with major transmission projects already under construction or in advanced planning. The Needs Study similarly found that current and long-term transmission plans in the West's Mountain and Southwest regions were largely consistent with its own estimates of future demand. The largest demands for interregional expansion were between the Mountain and Northwest regions, Mountain and Southwest regions, and the Southwest region and California (see Figure 14).

The Needs Study identified demand for an additional 3 GW to 26 GW of transfer capacity between its Northwest and Mountain regions. This aligns with a 3-GW pathway from the Montana IREZ to Seattle and Portland.

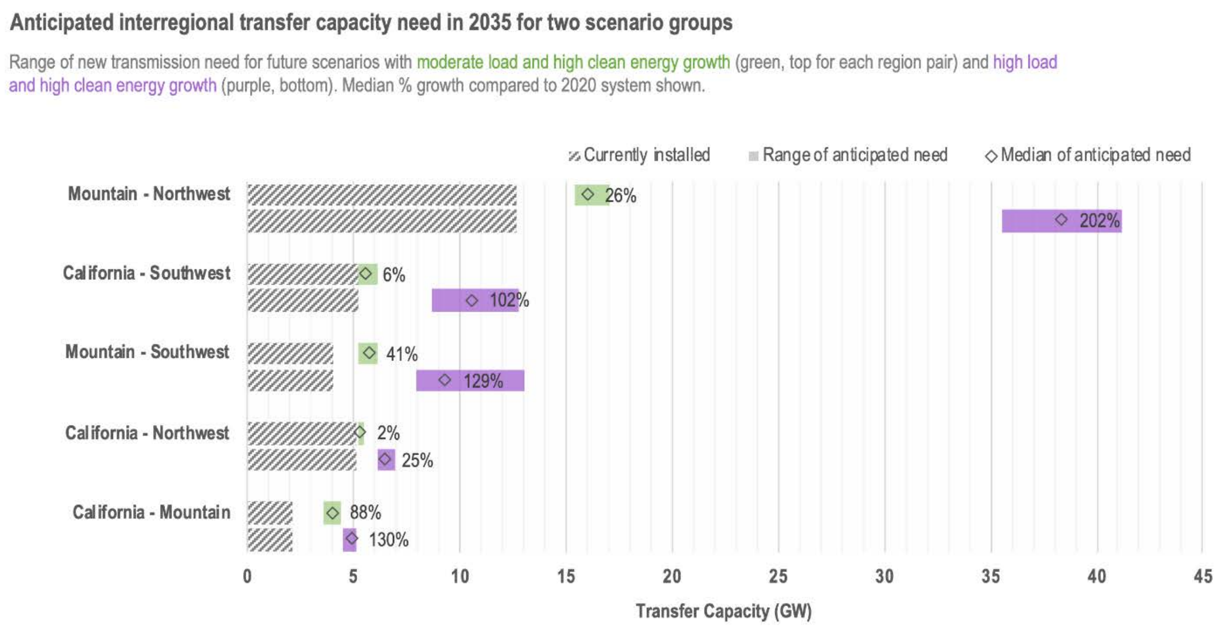

Chart adapted from Needs Study, Executive Summary (DOE 2023)

Figure 14. Needs Study findings aligning with Western IREZ corridors

6.2 The NTP Study

One of the most consistent trends across NTP Study scenarios is the demand for increased power flows from the nation's wind belt (primarily SPP and western MISO) to load centers in all eastern regions. Corridors from the Oklahoma, Kansas, Nebraska, and Iowa IREZs are all consistent with these eastward flows.

The NTP Study modeled CONUS-wide scenarios for AC-only transmission expansion, new point-to-point HVDC connections in addition to AC expansion, and AC expansion allowing a multi-terminal HVDC "macrogrid" network. Map A in Figure 15 illustrates new transmission buildouts by 2050 if point-to-point HVDC links are allowed to be part of the solution. These scenarios do not force HVDC into the solution; rather, they assume that AC and point-to-point DC are both available. Map B shows results for scenarios that further allow both point-to-point HVDC and a networked HVDC "macrogrid" over the AC network.

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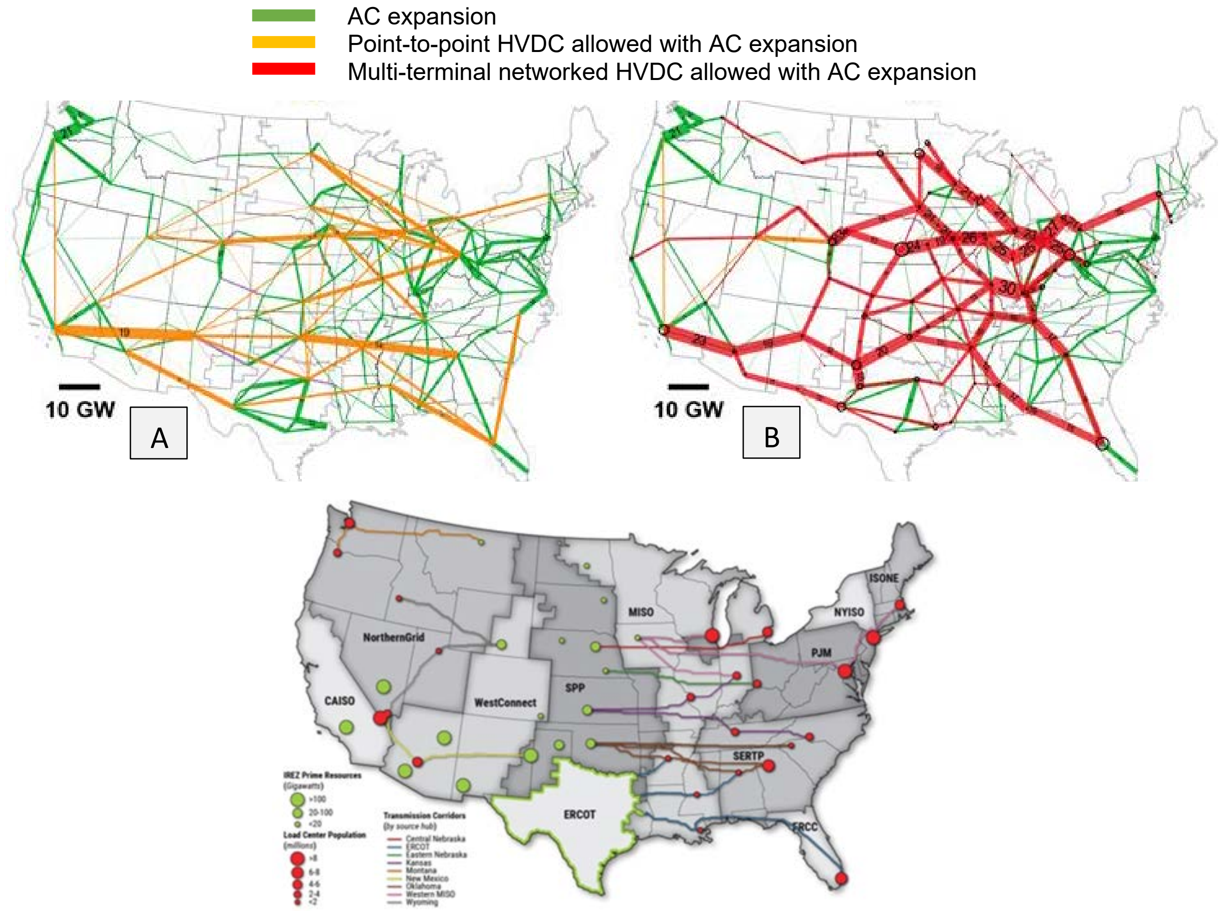

IREZ corridors

Core scenarios for 90% grid decarbonization by 2035, with moderate demand growth and current policies. Endpoints represent the geographic center of a planning area and not recommended sites for substations. Lines represent the optimal transfer capacity between two areas and not specific transmission configurations (DOE forthcoming).

Figure 15. Transmission for 2050 identified in NTP Study core scenarios

Some of the strongest alignments between IREZs and NTP Study results involve the corridor from the Oklahoma IREZ to Atlanta; from the Iowa IREZ to western PJM with additional connections to New York, New England, and eastern PJM; and from ERCOT to Florida.

The NTP Study's HVDC scenarios identify a possible demand for transfers across the east-west interconnection seam. This is an apparent difference from the IREZ analysis, where no corridor (apart from those in the solar scenarios) crosses the seam. The different outcomes are not necessarily in conflict, however. The NTP Study results include transmission buildouts at 5-year increments as far into the future as 2050, whereas several IREZ corridors show evidence of being cost-effective immediately. If the IREZ corridors demonstrate cost effectiveness today, they would tend to be developed first. Later development of other transmission—including cross-seam HVDC links—would serve other later needs (resource adequacy and reserve sharing, for example) that were not elements of the IREZ analysis.

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The NTP Study included complete decarbonization of the electric grid as a modeling objective, meaning that the models found the best solutions to achieving decarbonization given the inputs and constraints included in the assumptions. The IREZ analysis, on the other hand, does not enforce any kind of decarbonization goal. Therefore, IREZ corridors with a large benefit-to-cost ratio are essentially high-opportunity first steps on the path to decarbonization that states can consider even without a specific decarbonization target.

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7 Opportunities for Future Work

The results in Table 6 and Table 7 are initial snapshots of whether further study of an IREZ corridor is reasonable. Our analysis addresses two readily quantifiable benefits—reduced energy cost and resource adequacy—but does not quantify the benefits of decarbonization or increased resilience.

Metrics are still experimental, but states and stakeholders may nevertheless reach their own consensus on the resilience value of interregional transmission. Rather than impose experimental assumptions (which states would necessarily revisit in public stakeholder processes), we set resilience aside and have focused instead on the benefits we can quantify with a high degree of confidence. If an IREZ corridor can provide measurable net benefits for reduced energy cost and better resource adequacy, resilience would be a bonus benefit regardless of how it might be measured.

The benefits of accelerating grid decarbonization are related to public policy. Three critical questions related to its implementation are how much decarbonization should be achieved; by when should it be achieved; and what are the allowable cost trade-offs that may be passed on to the public. Whatever state or federal goals for grid decarbonization may be in force, however, the way forward will involve many solutions—some coming earlier than others because they are feasible and cost-effective using technologies that exist today. We have assumed here that transmission expansion is part of that solution and that IREZs can be part of the transmission solution set. Therefore, this analysis does not depend on any specific decarbonization goal. Our results suggest that some IREZs can be immediate next steps in grid decarbonization with very little cost trade-off for the public regardless of the public policy goal. Where the results do suggest a trade-off, we assume that states would determine what is acceptable and pursue follow-on analyses that would inform their decisions.

7.1 Uncertainty

We have attempted to manage uncertainty by relying on the most recent observed data to estimate project costs, energy costs, and other inputs. These will necessarily change over the time it takes to build a 600-kV transmission line, however. Consequently, a source of uncertainty in this report is the trajectory of future changes from the observed data used to anchor the analysis. We recommend that a future analysis for a specific IREZ corridor incorporate stakeholder expectations for fuel costs, demand growth, and plant retirements that might affect the load center's cost of energy and resource adequacy in the future.

For example, NREL's Annual Technology Baseline anticipates that LCOEs for photovoltaic solar plants will decline over the next 10 years by between 15% and 44%, while onshore wind LCOEs will decline by between 14% and 32% (NREL 2023). New IREZ plants and new local plants might end up at different ends of those ranges. A related uncertainty not addressed in this study is the effect of renewable energy tax credits under the 2022 Inflation Reduction Act—specifically, whether they will benefit local projects more than IREZ projects.

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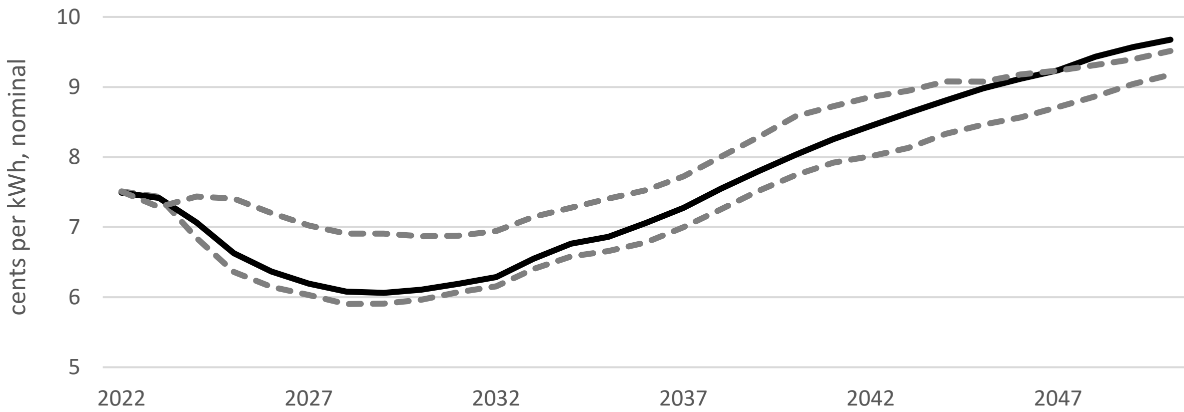

Source: EIA 2023d. Solid line is EIA's reference case. The two dashed lines are EIA's sensitivity cases for high and low natural gas supply.

Figure 16. EIA projection for energy generation costs, with inflation assumptions

Figure 16 shows forecasts for average annual generation costs across all technologies simulated by DOE's Energy Information Administration (EIA), including a scenario assuming low supplies and high prices for natural gas and one assuming high supply and low prices for natural gas (EIA 2023d). The range illustrates some of the uncertainties involved in analyzing long-term economic impacts.

7.2 Alternative Transmission Configurations

The 600-kV HVDC standard transmission assumption is another element that states could change and test in a future study. Two factors could provide opportunities for cost savings that are not captured in this analysis.

7.2.1 AC Versus DC

HVDC is a reasonable standard assumption for long-distance interregional transmission—the main focus of this analysis—because across distances spanning many hundreds of miles it tends to have a lower cost per megawatt of transfer capacity than an AC line of comparable voltage does (WECC 2019, Weimers 2011). Conversely, however, assuming HVDC over shorter distances is tenuous because AC tends to be more cost-effective. Short-distance cost estimates in this analysis should be regarded as the cost to beat for alternative transmission configurations. This is especially important for multidestination corridors such as Oklahoma to Atlanta and Greenville, where power from the Oklahoma IREZ could be delivered on a DC line to Atlanta, with the final 63 miles to South Carolina served by a smaller AC line.

In addition, the ROW width requirement for HVDC with a multipole configuration may be smaller than that of HVAC for the same power transfer capability. It is possible even to string a pole with both HVDC and HVAC, although additional protection and insulation might offset some of the structure savings. A shared structure might also increase the height of the tower depending on the conductor phasing structure of the parallel AC and DC lines.

Finally, running multiple high-voltage lines along a common corridor—whether AC or DC—provides a single point of failure, for example, because of a climatic weather event such as a

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tornado, hurricane, icing, or wildfire. In this context, a power stability study for a single contingency event may need to consider compound probability of more than one contingency, which could impact the cost savings if redundant power flow paths are needed.

Another component of HVDC and AC voltages is the trade-off between investment cost and delivered energy. For short distances, AC provides a lower cost primarily because of the high-cost converter stations associated with HVDC lines. As an example, Weimers (2011) indicated that costs become greater for 750 kV AC than 500 kV HVDC and the breakeven is around 360 miles at 3,500 MW of capacity. For 750 kV HVDC, the breakeven is little over 500 miles. In addition, line losses are greater for AC than DC. An 800-kV AC transmission line realizes a 4% loss at 400 miles and an 11% loss at 870 miles while the 750-kV DC transmissions realize a little more than 2% loss and a 6% loss at the same distances, respectively. HVDC lines are also less sensitive to weather conditions than AC lines. In addition, the number of AC lines required to equal capacity of electricity can be as much as double at 600 kV (Weimers 2011).

One example of a possible future study is from the Montana IREZ to Portland and Seattle. An existing 500-kV transmission pathway from the Colstrip coal plant in southeastern Montana has carried power to Seattle and Portland for the past half century. Two Colstrip units retired in 2020, and Avista sold its interest in the other two units at the plant but retained transmission rights (Avista 2023). Meanwhile, BPA—which owns and operates the western segment of the Colstrip pathway, announced $1.35 billion in transmission upgrades. These upgrades might provide additional options for the Montana IREZ corridor to Pacific Northwest load centers in the context of a broader transmission expansion plan (BPA 2023). The feasibility of doing so would require a path-specific study that incorporates current plans for use of the upgrades.

7.2.2 LCC Versus VSC Technology

An AC-DC converter station constitutes a large part of HVDC transmission costs. Historically, HVDC lines have used line-commutated converters (LCC), but a newer technology (voltage-sourced converter, or VSC) provides additional benefits and is maturing quickly. Table 8 compares the two converter types. VSC is less efficient than LCC with respect to power transfer, although VSC is improving. In Europe, VSC has been a major part of accelerated HVDC deployment for offshore wind. Thus far, VSC has typically cost 10% to 30% more per MW-mile than LCC technology. Some industry observers say that costs may come down with efficiency advances in insulated gate bipolar transistors (IGBT) and metal oxide semiconductor field effect transistors (MOSFET) (Liserre et al. 2023).

Table 8. Comparison of LCC and VSC Converter Technologies

LCC		VSC	
Benefits	**Drawbacks**	**Benefits**	**Drawbacks**
Mature technology; thyristor-based since the 1970s Cheaper than previous technology based on mercury valves	Large need for reactive power Need large AC filters for high harmonic content Should not be connected to passive grids with no AC voltage generator or weak grids with no reactive power source	Less need for reactive power and independent control of active and reactive power Generated voltage is in smaller voltage steps; no need for filters Easier reversal power flow capability Black start capability Lower short-circuit ratio	Large number of semiconductors required so higher costs (but IGBTs and MOSFETs are decreasing in cost because of performance and design improvements)

Source: Liserre et al. 2023

7.3 Resource Adequacy

A path-specific study could also monetize the impact of IREZ resources on resource adequacy, which we have not done in this analysis. Although IREZ resources might have a greater impact on resource adequacy than an identical quantity of local wind or solar might, their monetary value will depend on the degree to which the local planning reserve margin applicable to the load center is above or below its benchmark value. That in turn will depend on planned generator retirements and load growth. A path-specific study could take these variables into account.

7.4 Other Areas

Other limitations explained previously in this report that can be explored in follow-on analyses include the following:

- The corridors shown on the maps are not recommendations for specific transmission routes. They represent estimations of the least-cost pathways based on high-level known data about terrain, land costs, and other factors. Their purpose is to provide a more reasonable estimation of line miles.
- Transmission substations may be anywhere in an IREZ and need not be at the point shown on our map. These points represent the geospatial center of the zone, but the DC converter may be located somewhat closer to the target load center.
- The size of a 3-GW transmission line relative to local peak load indicates an IREZ's potential contribution to the local fuel mix given the assumptions of a 600-kV HVDC connection. If the IREZ contribution to peak is large, a partnership with neighboring states and load centers to jointly develop a shared IREZ corridor might be beneficial.
- A future IREZ corridor-specific study could include projects in the local interconnection queue, including battery storage. The study could also take into account announced plans for grid enhancing technologies, dynamic line ratings, smart transformers, or other power electronics/topology optimization.

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8 Conclusions and Next Steps

The IREZ corridors explored in this analysis constitute some of the low-hanging fruit on the path to decarbonizing the nation's electricity sector. They extract the most value from known and commercially mature technologies—wind and solar power—and they can deliver that value directly to the customers who would be paying for it.

This analysis provides reason to believe that well-planned IREZ transmission pathways can yield benefits that are greater than their costs. Generation cost savings would likely be enough by themselves to offset the cost of interregional transmission in most cases. Evidence also points to additional resource adequacy benefits from many corridors. If these two benefits—generation cost savings and improved resource adequacy—are greater than transmission costs, the additional protection against major grid disruptions would be an added benefit no matter how the resilience value might be measured.

Our goal for this report was to establish an initial knowledge base that could be passed to state and regional decision makers to guide further and more detailed investigation. The standardized analytical assumptions used here could not account for all case-specific factors that might affect transmission decisions. Investigating these issues in an analysis that focuses solely on the IREZ corridor would provide customized answers, and the investigation would have significantly greater weight if it were initiated by state and regional decision makers.

Subsequent state-led investigations will also allow stakeholders to weigh in on the crucial question of how to deal with future uncertainty. We have deliberately avoided speculation about future energy costs, fuel costs, renewable energy production, repurposing of resources, and resource mixes in this analysis. Instead, the analyses for generation cost savings and resource adequacy rely on current data. This approach sacrifices a precise matching of hourly variations in prices for 2022 with hourly variations in renewable energy output. On the other hand, these historical data require no guesswork as to their real value. We believe that understanding the caveats associated with using historical data will at least provide an anchor point that decision makers can use for considering a variety of possible futures.

The congruence between IREZ corridors and findings in the Needs Study and the NTP Study also suggests collateral benefits beyond those realized by affected states directly. The scenarios tested in the NTP Study capture global interdependencies in national transmission buildouts, changes in generation mix, and the use of energy storage. Consequently, a specific IREZ corridor that aligns with NTP Study findings could have regional and national benefits that ripple beyond benefits to the target load center.

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