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Integrated Grid Optimization for Deep Decarbonization: A Multi-ISO Simulation Study across MISO, CAISO, and ERCOT (2025–2030)

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Abstract
As renewable energy penetration rapidly increases, Independent System Operators (ISOs) face unprecedented challenges in balancing cost, emissions, and reliability. This study introduces an Integrated Grid Optimization (IGO) framework, combining siting, transmission expansion, market dispatch, and inverter stability solutions. Using publicly available datasets and the open-source GridPath platform, we simulate coordinated scenarios (30%, 50%, and 80% VRE) from 2025 to 2030 across MISO, CAISO, and ERCOT. Results demonstrate that the IGO framework can reduce CO_2 emissions by up to 80%, maintain high reliability, and minimize total system cost through optimal placement of HVDC overlays, battery storage, and grid-forming inverters. This provides a replicable blueprint for cost-effective, stable renewable integration across large grid footprints.

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1. Introduction

The integration of large-scale renewable energy resources is a central challenge for power system operators (Yongning *et al*., 2019; Syranidou *et al*., 2020). In the U.S., MISO, CAISO, and ERCOT together represent a substantial portion of national load and generation. However, transmission congestion, grid reliability, and queue backlogs pose major hurdles. This addresses these interlinked issues through a systemic framework Integrated Grid Optimization (IGO)—that enables ISOs to accommodate high renewable penetration (30–80% VRE) by 2030 while minimizing emissions and maintaining system performance.

The decarbonization of the United States electric grid is an urgent and pivotal goal in the broader strategy to mitigate climate change and limit global temperature rise to well below 2°C, in alignment with the Paris Agreement. Power generation currently accounts for approximately one-third of the nation's greenhouse gas emissions, and decarbonizing this sector is foundational to the electrification of transportation, heating, and industrial systems (Alshahrani *et al*., 2019; Kumar *et al*., 2019). As federal, state, and corporate commitments toward net-zero carbon emissions intensify, achieving significant emissions reductions from the power sector by 2030 has emerged as a critical milestone. Realizing this target demands not only a rapid deployment of zero-carbon technologies such as wind, solar, and battery storage, but also a transformation of the grid infrastructure that supports them (Kabeyi and Olanrewaju, 2022; Anika *et al*., 2022). Static, siloed, and aging transmission networks must evolve into dynamic, integrated systems capable of managing variability, enabling flexibility, and facilitating power flow across regional boundaries. Interregional coordination and grid optimization are central to this transformation. The United States electric grid is divided into multiple balancing authorities and regional transmission organizations (RTOs) or independent system operators (ISOs), which historically have operated with limited collaboration (Hansen and Heller, 2021; Lenhart and Fox, 2022). This fragmentation limits the ability to leverage geographic diversity in renewable resources, results in unnecessary curtailment of clean energy, and exacerbates reliability challenges during system stress. Enhanced coordination between ISOs—specifically the Midcontinent Independent System Operator (MISO), the California Independent System Operator (CAISO), and the Electric Reliability Council of Texas (ERCOT)—presents a substantial opportunity to improve grid efficiency and resilience (Parent *et al*., 2021; Learner, 2023).

Each ISO exhibits distinct characteristics: MISO spans a wide geographic area with growing wind capacity; CAISO leads in solar penetration but faces overgeneration and curtailment issues; and ERCOT, while isolated from other grids, is rich in both wind and solar potential. A unified approach to transmission planning, generation siting, and market operations across these three regions could unlock synergies that accelerate decarbonization and reduce system costs (Bødal *et al*., 2020; Matteoli *et al*., 2021).

This undertakes a comprehensive analysis of integrated grid optimization strategies across MISO, CAISO, and ERCOT from 2025 to 2030. It simulates multiple decarbonization pathways using high-resolution datasets and scenario modeling to assess how regional coordination, advanced transmission expansion (including HVDC overlays), and strategic renewable siting can contribute to emissions reductions, economic efficiency, and system reliability. The simulation framework includes tools for GIS-based resource assessment, interconnection cost modeling, market co-optimization, and reliability analytics. By capturing the spatial and temporal dynamics of energy supply and demand, this identifies critical investments and operational reforms required for a deeply decarbonized grid (Niu *et al*., 2021; Kockel *et al*., 2022).

The primary objectives of this research are fourfold. First, to evaluate the impact of integrated transmission expansion across ISOs, including the feasibility and benefits of high-voltage direct current (HVDC) networks in connecting remote renewable resources with demand centers. Second, to optimize siting of renewable generation by incorporating geographic, economic, and interconnection constraints using spatially explicit models. Third, to simulate multi-regional market dispatch under high-renewable penetration scenarios, examining implications for price volatility, curtailment, and capacity adequacy. Fourth, to assess system reliability and stability through metrics such as grid inertia, fast frequency response, and loss-of-load probability under varying levels of regional cooperation. Together, these objectives aim to provide a data-driven, system-wide perspective on how interregional planning and market integration can drive deep decarbonization while maintaining grid reliability and economic viability.

This work contributes to the policy and planning discourse by quantifying the benefits of grid integration and offering actionable insights into infrastructure investment, regulatory reform, and market design. It provides an analytical foundation for decision-makers at the federal and state levels, as well as stakeholders across the electricity ecosystem, to collaboratively accelerate the transition to a carbon-free power system.

2. Methodology

2.1 Overview

We simulate the power systems of MISO, CAISO, and ERCOT from 2025 to 2030 under three renewable penetration scenarios (30%, 50%, 80%). The model co-optimizes generation, storage, HVDC overlay, and ancillary services using GridPath. Data inputs include NREL's WIND Toolkit, EIA/ISO interconnection queues, and real-world capacity expansion data.

2.2 Scenario Definitions

To assess pathways for decarbonizing the U.S. electric grid by 2035, three distinct scenarios were defined to capture the evolving landscape of policy, technology, and market dynamics (Cresko *et al*., 2022; Kazimierczuk *et al*., 2023). These scenarios—S1 (Baseline), S2 (Moderate), and S3 (Aggressive Net-Zero)—represent a structured framework for evaluating the operational, economic, and reliability impacts of increasing variable renewable energy (VRE) penetration. The scenarios integrate key drivers such as renewable adoption rates, load growth, energy storage capacity, demand-side flexibility, carbon pricing, and grid control technologies, each aligned with a different level of ambition and policy support as shown in table 1.

The Baseline scenario (S1) reflects a continuation of existing trends, with no major policy shifts beyond what is currently enacted. It assumes a 30% VRE penetration by 2030, driven primarily by market forces and state-level renewable portfolio standards (RPS), without federal mandates or an economy-wide carbon price. The generation mix retains a significant share of natural gas and coal, with modest retirements of aging fossil assets.

Load growth is moderate (~1% per year), driven by economic growth and some electrification of transportation and buildings. Energy storage deployment is limited to 10 GW nationally, driven by economic signals in high-solar regions like California. Demand flexibility remains minimal, constrained by lack of dynamic pricing and automation infrastructure. Grid controls are largely based on conventional grid-following inverters, with limited inverter-based resource (IBR) support for frequency and voltage regulation (Sajadi *et al*., 2023; Mitra *et al*., 2023). Under this scenario, the system continues to rely heavily on dispatchable fossil generation to ensure reliability, and curtailment of renewables is relatively low due to limited penetration. Without significant carbon policy levers, emissions reductions plateau around 30–35% below 2005 levels by 2030.

Scenario S2 incorporates the full implementation of the Inflation Reduction Act (IRA) and related federal clean energy incentives. It assumes 50% VRE penetration by 2030, aligning with targets set forth in recent federal modeling exercises. This scenario anticipates accelerated coal retirements, rapid wind and solar buildout, and substantial investment in grid-scale batteries and interregional transmission.

Load growth increases to ~1.5% per year, reflecting higher electrification rates, particularly in transportation (EV adoption) and building heating (heat pumps). Energy storage scales to over 30 GW, enabling greater renewable integration and providing ancillary services. Demand flexibility improves moderately, with 5–10% of peak load responsive to price signals, aided by time-of-use tariffs and advanced metering. Grid control technologies include a mix of grid-following and grid-forming inverters, especially in regions with high inverter-based resource saturation. Policy support includes production tax credits (PTC) and investment tax credits (ITC) for renewables and storage, streamlined siting for transmission, and implicit carbon pricing via clean energy standards and utility procurement mandates (Sivaram and Kaufman, 2019; Saha *et al*., 2021). These drivers support substantial emissions reductions—over 50% below 2005 levels—while maintaining system reliability through enhanced operational flexibility and a diversified portfolio of clean resources.

The Aggressive scenario (S3) envisions a transformative shift in the U.S. power sector toward near-total decarbonization. It targets 80% VRE penetration by 2030, consistent with net-zero emission pathways modeled by national labs and international energy agencies. This scenario assumes full national mobilization, including carbon pricing mechanisms, high public and private investment, and rapid technology deployment.

Load growth is high (~2% annually), driven by widespread electrification across transport, industry, and buildings. Energy storage expands dramatically, exceeding 80 GW, including long-duration storage technologies (e.g., flow batteries, hydrogen) that smooth multi-day variability. Demand flexibility is deeply integrated into system operations, with 15–20% of load responsive via automated controls, demand response markets, and load aggregators. Grid-forming inverter technology becomes widespread, deployed on over 80% of inverter-based resources, enabling synthetic inertia, frequency stability, and autonomous voltage support. Policy support includes a federal carbon price starting at $60/ton CO_2 and rising over time, in addition to clean electricity standards requiring 80% clean generation. Aggressive transmission expansion (including HVDC interties) and streamlined interconnection policies are assumed (Bloom *et al.*, 2021; Nilsson, 2023). Under this scenario, CO_2 emissions fall by nearly 80%, approaching net-zero in the power sector, while system reliability is maintained through diverse clean capacity, smart grid controls, and regional balancing.

Table 1: Comparative Grid Implications

Scenario	VRE Penetration	Policy Assumptions	Grid Controls
S1 (Baseline)	30%	Current Trends	Grid-following
S2 (Moderate)	50%	IRA-Compliant	Mixed inverters
S3 (Aggressive)	80%	High Decarbonization	Grid-forming

The progression from S1 to S3 illustrates not only increasing ambition in terms of renewable integration, but also the need for deeper structural changes from market design and grid modernization to more dynamic system controls. The shift to grid-forming inverters in S3 represents a significant technological leap, ensuring stability in low-inertia, high-VRE environments. Similarly, the increasing role of demand-side flexibility in S2 and S3 helps mitigate variability, reduce peak demands, and improve system resilience.

These scenario definitions serve as a foundation for evaluating trade-offs between cost, reliability, and emissions across different policy and technology futures. By systematically varying renewable penetration, policy instruments, and grid control sophistication, the modeling framework captures the complexity of transitioning to a deeply decarbonized power system (Bolwig *et al.*, 2019; Sheykhha and Madlener, 2022). The results provide critical insights for planners, regulators, and stakeholders navigating the U.S. grid's transformation over the next decade.

2.3 Tools & Datasets

Accurate modeling of a decarbonized electric grid requires an integrated suite of software tools, high-fidelity datasets, and robust computational frameworks. In the context of long-term planning and operational assessment for deep decarbonization pathways, such as those modeled for the U.S. electric grid, multi-scale modeling is essential—encompassing generation expansion, unit commitment, economic dispatch, transmission constraints, and reliability metrics. This analysis relied on the GridPath platform as the central modeling engine, supported by a diverse array of industry-standard datasets from NREL, EIA, NOAA, and regional ISOs.

The backbone of the modeling framework was GridPath, an open-source, modular power system model capable of simulating long-term investment decisions (generation and transmission expansion) alongside short-term operational behavior (commitment and dispatch). GridPath's architecture enables chronological simulations with hourly resolution (8,760 hours per year), unit-level fidelity for thermal and storage assets, and linearized power flow approximations to account for transmission constraints (Gropp and Davenport, 2021; Wang *et al.*, 2023).

GridPath was configured to run across a six-year horizon (2025–2030) under three decarbonization scenarios, capturing the joint impacts of renewable buildout, storage deployment, and market design changes. The simulation included nodal-level granularity for major ISO regions (MISO, CAISO, ERCOT), with embedded logic for reserve procurement, storage arbitrage, congestion management, and curtailment minimization. These capabilities allowed for co-optimization of operational and investment decisions, offering a realistic view of the trade-offs between capital expenditures and system flexibility.

Accurate representation of renewable energy potential was enabled through integration of high-resolution meteorological and resource datasets. For wind energy, the NREL WIND Toolkit provided 100-meter resolution wind speed and capacity factor data across the continental U.S., spanning multiple years to capture interannual variability (Brown and Botterud, 2021; Mokry and Center, 2022). For solar generation, the National Solar Radiation Database (NSRDB) was used, offering sub-hourly irradiance data downscaled to 4-km resolution, with site-specific performance models for fixed-tilt and single-axis tracking PV systems.

Resource potential was spatially matched to modeled generator candidates using GIS overlays and land exclusion filters based on slope, land use, protected areas, and proximity to transmission infrastructure. This ensured that only technically and socially viable zones were considered for utility-scale deployment. GridPath then selected optimal build locations from a filtered set of wind, solar, and hybrid (wind+solar+storage) resource options.

To represent existing and proposed thermal assets, the model used plant-level operational data from EIA Form 860, including fuel type, heat rates, ramping constraints, and outage characteristics. Retirement assumptions were benchmarked against announced coal phase-out schedules and NERC regional reliability reports.

The transmission network was reconstructed using EIA Form 930/860 data on substation locations and interties, complemented by ISO-specific transmission topology maps and interconnection coordinates. Regional aggregation zones were constructed based on LMP nodes and balancing authority boundaries, allowing for explicit modeling of congestion, line limits, and wheeling losses. Existing transmission corridors were parameterized with reactance and capacity ratings, while candidate HVDC lines were added based on techno-economic cost curves and feasibility analyses (Reed *et al.*, 2020; Yang and Li, 2022).

Congestion pricing and transmission shadow prices were derived within GridPath's linear optimal power flow (LOPF) formulation, providing locational marginal prices (LMPs) for each modeled node. This structure supported dynamic estimation of curtailment rates, transmission bottlenecks, and regional price differentials, informing both operational dispatch and long-term grid investment.

Market mechanisms were explicitly modeled to reflect the economic signals governing generator behavior and system-wide reliability. Locational marginal pricing (LMP) was calculated for all hours, capturing the intersection of energy, congestion, and loss components at each node. The Operating Reserve Demand Curve (ORDC) was used to simulate scarcity pricing during tight system conditions, particularly relevant in ERCOT and MISO, where reserve pricing plays a significant role in incentivizing fast-ramping resources and flexible generation.

Ancillary service requirements—such as spinning, non-spinning, and frequency reserves—were co-optimized with energy and storage dispatch. GridPath's dispatch engine accounted for storage state of charge dynamics, minimum run times, and reserve availability, offering a complete picture of system flexibility and inertia provisioning under different resource mixes (Calero *et al*., 2022; Parzen *et al*., 2023).

Several additional datasets were integrated to support weather-correlated demand, outage modeling, and generator siting. NOAA weather reanalysis data provided temperature and wind speed profiles, used to construct load forecasts and model weather-sensitive demand spikes, such as heatwaves or cold snaps. Interconnection queue data from ISO/RTOs were also used to weight candidate renewable projects, prioritize queue-mature sites, and analyze historical project attrition patterns.

Economic assumptions, including capital and operational costs for all generation and transmission technologies, were drawn from the NREL Annual Technology Baseline (ATB), with scenario-aligned cost trajectories for wind, solar, batteries, and HVDC lines. These assumptions informed net present value (NPV) comparisons, marginal abatement cost curves, and long-term cost-benefit assessments across scenarios.

The combination of GridPath's co-optimization capabilities, high-resolution resource and transmission datasets, and realistic market constructs enabled a robust simulation of the U.S. grid's decarbonization trajectory. Through this integrated modeling framework, this provided actionable insights into the operational, economic, and spatial implications of transitioning to a high-renewables power system. The tools and datasets outlined here form the technical foundation for evaluating policy, market design, and infrastructure strategies that can guide the grid toward a reliable, cost-effective, and low-carbon future (Bhattarai *et al*., 2019; Hampton and Foley, 2022).

3. Baseline System Characterization

Understanding the existing state of the electric grid is a critical precursor to modeling deep decarbonization scenarios. The U.S. grid is operated through multiple Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs), each with unique infrastructure portfolios, market mechanisms, and regulatory frameworks. This section characterizes the baseline system conditions of three key regions—CAISO (California ISO), MISO (Midcontinent ISO), and ERCOT (Electric Reliability Council of Texas)—focusing on generation mix, transmission capacity, flexibility resources, and existing operational constraints.

CAISO operates most of California's electric grid and has been a national leader in renewable energy integration. As of 2024, the CAISO region maintains a generation portfolio dominated by natural gas (approximately 40% of installed capacity), solar PV (25%), hydroelectric (10%), wind (7%), and imports from the Pacific Northwest and Southwest. The system has achieved over 35% annual renewable energy penetration, with daily solar contributions peaking above 70% during midday hours in spring and fall.

A defining feature of CAISO's grid is the "duck curve," a representation of net load shaped by solar overgeneration and steep evening ramps. This creates significant challenges in load balancing and highlights the need for flexible resources, including battery storage and dispatchable gas-fired generation. As of 2024, CAISO has over 7 GW of battery storage capacity online, making it the national leader in storage deployment. However, the system still faces curtailment issues, especially during spring months when demand is low, and solar generation is high.

Transmission constraints are another major issue, particularly in delivering renewable power from inland regions (e.g., Central Valley, Imperial County) to coastal load centers (Makholm, 2022; Medina *et al*., 2022). Additionally, California's limited interregional transmission ties—especially with the Pacific Northwest and the Desert Southwest—restrict the state's ability to share excess renewable generation or access low-cost imports during tight supply periods. Regulatory and permitting hurdles further slow transmission expansion.

MISO spans a broad geographic area across the Midwest and Southern United States, encompassing 15 U.S. states. The system's generation mix remains dominated by coal (~35% of capacity), followed by natural gas (~30%), nuclear (~15%), and wind (~12%). MISO is notable for its significant wind generation potential, particularly in Iowa, Minnesota, and the Dakotas, which host some of the best wind resources in the country.

MISO faces a complex set of challenges related to its aging thermal fleet, limited transmission infrastructure in renewable-rich areas, and growing demand from electrification. While wind capacity is expanding, much of it is located in "congested zones," where transmission bottlenecks lead to curtailment and suppressed capacity value. MISO has also seen rising interconnection requests for solar and storage resources, though lengthy interconnection study processes have delayed deployment.

Reliability is another concern, particularly during extreme weather events like polar vortices and heat waves, which stress the system's aging fossil assets and limited demand-side flexibility. MISO operates a capacity market but lacks fully integrated demand response programs and large-scale storage resources. These constraints limit its ability to respond dynamically to variable generation and rising load volatility.

ERCOT manages the electric grid in most of Texas and operates independently from the Eastern and Western Interconnections, making it electrically isolated (Glenn *et al*., 2021; Du, 2023). The generation mix is characterized by natural gas (~45%), wind (~25%), solar (~10%), and coal (~12%), with no nuclear expansion. Texas leads the nation in installed wind capacity and is rapidly adding solar, with more than 10 GW of solar additions expected between 2024 and

2026.

While ERCOT has excelled in renewable deployment due to its market-driven structure and ample land, its isolation from other grids limits its ability to import power during system stress. This vulnerability was made evident during Winter Storm Uri in 2021, which led to prolonged blackouts and highlighted weaknesses in generation weatherization, resource adequacy, and system planning.

ERCOT lacks a formal capacity market and instead relies on an energy-only market to incentivize investment, a structure that introduces volatility and can underprice reliability services. Furthermore, while transmission infrastructure has improved under the Competitive Renewable Energy Zones (CREZ) program, congestion persists, particularly in West Texas where wind and solar are abundant but load centers are distant. Each ISO begins the decarbonization journey from distinct baseline conditions. CAISO leads in storage and renewable penetration but struggles with curtailment and interregional coordination. MISO has vast renewable potential constrained by outdated transmission and a coal-heavy fleet. ERCOT demonstrates rapid clean energy growth but suffers from grid isolation and market design vulnerabilities. A comprehensive understanding of these baseline characteristics is essential for evaluating future decarbonization scenarios and designing effective interventions (Andrei *et al*., 2021; Lerbinger *et al*., 2023).

3.1 Midcontinent Independent System Operator (MISO)

The Midcontinent Independent System Operator (MISO) manages the bulk electric transmission system across a vast footprint spanning 15 U.S. states from the Gulf Coast to the Upper Midwest, and the Canadian province of Manitoba. With a peak load of approximately 120 GW in 2022, MISO is one of the largest grid operators in North America (Wiseman, 2022; Wilson and Zimmerman, 2023). It plays a central role in national decarbonization efforts, yet its structural and market characteristics present unique challenges for renewable energy integration.

MISO's service territory is characterized by diverse generation assets, significant industrial and agricultural load centers, and large spatial disparities between energy supply and demand. As of 2025, MISO's operational portfolio includes approximately 30 GW of wind and 7 GW of solar capacity, with those figures expected to grow rapidly amid ongoing coal retirements and clean energy mandates. However, the region's aging transmission infrastructure and complex interconnection landscape have significantly hampered the pace of renewable deployment.

Historically, MISO has relied heavily on coal-fired generation, which in 2022 still accounted for nearly 40% of its electricity production. However, a rapid shift is underway: more than 20 GW of coal capacity is scheduled for retirement by 2030, driven by aging infrastructure, emissions regulations, and market economics. Natural gas has filled much of the resulting dispatchable capacity gap, while renewables—especially wind—are expanding in states like Iowa, Minnesota, and the Dakotas.

Wind energy has found favorable development conditions in MISO's northern and western regions, where land availability and strong wind resources coincide. The Central and Northern MISO regions, including parts of Minnesota, Iowa, and the Dakotas, have become wind deployment hubs. Solar growth has been slower but is gaining traction in southern areas such as Louisiana, Arkansas, and Mississippi, where solar irradiance is higher and land use constraints are less pronounced (Tabassum *et al*., 2021; Levin *et al*., 2023).

Despite these advancements, coal remains a stabilizing resource for reliability, particularly during seasonal peak demand and low-wind events. MISO's market planners face a dual challenge: phasing out carbon-intensive assets while ensuring sufficient firm, dispatchable capacity to meet reserve margin targets and extreme weather resilience.

MISO's transmission topology reflects both its geographic scale and historical evolution. The grid consists of a loosely meshed network with limited high-capacity transmission connecting remote renewable-rich zones with major urban load centers such as Chicago, Detroit, Indianapolis, and New Orleans. This mismatch between resource locations and demand zones creates significant congestion and leads to high curtailment rates, particularly for wind energy.

Furthermore, the central spine of MISO's system—often referred to as the "Seam" with the Southwest Power Pool (SPP)—has emerged as a critical bottleneck for east-west power transfers. Internal congestion between MISO North/Central and MISO South is also frequent, due to limited capacity across key interfaces like the Rudd–Shreveport corridor, which acts as a constriction point.

To address these issues, MISO has proposed its Long Range Transmission Planning (LRTP) framework, aimed at enhancing regional connectivity, supporting renewables, and improving system resilience. The first tranche of projects, approved in 2022, includes 18 new transmission lines spanning over 2,000 miles, but these will take several years to construct and may only partially address the anticipated capacity deficits (Thiam *et al*., 2023; Moses *et al*., 2023).

One of the most significant barriers to decarbonization in MISO is the severe congestion in the generator interconnection queue. As of 2025, hundreds of gigawatts of wind, solar, hybrid, and storage projects await interconnection studies and approvals. The problem is compounded by inadequate transmission headroom, long study timelines, and high upgrade costs, which have led to widespread project attrition. In 2020 alone, 278 queued projects were dropped, unable to meet financial and logistical hurdles imposed by the interconnection process.

This congestion reflects a broader structural challenge: renewable projects in MISO are often located far from existing substations and high-voltage lines. Developers face high network upgrade costs—sometimes exceeding $300/kW—which deter new investment and distort the geographic distribution of clean energy development. Furthermore, uncertainty in project timelines and upgrade cost allocation undermines investor confidence.

MISO has begun reforming its queue process to improve study accuracy and processing speed, adopting a clustered study approach that aligns resource planning with transmission upgrades. Nevertheless, the backlog remains substantial, and interconnection reform must be coupled with proactive transmission expansion to prevent further project attrition.

MISO sits at the center of the U.S. energy transition, both geographically and operationally. With a vast and diverse territory, it holds enormous potential for renewable energy deployment but faces serious transmission and interconnection bottlenecks. The dual challenge of retiring coal while integrating large-scale wind and solar calls for coordinated investment in grid infrastructure, market reforms, and planning processes (Lin and Bega, 2021; Bridle *et al*., 2022). If effectively managed, MISO could serve as a model for achieving deep decarbonization across a complex and expansive regional grid.

3.2 California Independent System Operator (CAISO)

The California Independent System Operator (CAISO) oversees the bulk of electricity transmission and wholesale market operations across most of California and parts of neighboring states. As a leading grid in renewable energy adoption, CAISO represents a crucial case study in the challenges and strategies of integrating high levels of variable renewable energy (VRE), particularly solar, into a modern electric power system. With 54% of its electricity coming from renewable sources in 2023, CAISO operates one of the most decarbonized grids in the U.S., balancing a peak system demand of 45 GW under stringent policy mandates, including Senate Bill 100, which commits the state to 100% clean electricity by 2045.

CAISO's generation portfolio is dominated by utility-scale and distributed solar photovoltaics (PV), which collectively contribute nearly 30% of total energy generation on an annual basis, and frequently exceed 50% of real-time supply during midday hours. This results in a highly diurnal net load profile, characterized by the so-called "duck curve"—a deep midday drop in net load due to high solar output, followed by a sharp increase (or "ramp") in net demand during the early evening hours as solar generation fades and residential demand peaks. This dynamic ramp has posed increasing operational challenges, particularly in managing fast-ramping dispatchable resources to fill the gap left by solar decline (Carlini *et al*., 2019; Sun *et al*., 2021). In 2023, CAISO faced several days with evening ramps exceeding 13 GW in just three hours, requiring rapid activation of natural gas peakers, imports, and battery discharge. This issue is exacerbated during spring months when solar production is high but load is relatively low, amplifying the midday oversupply and leading to increased curtailment.

With rising solar penetration, CAISO has experienced a sharp increase in renewable curtailment events, particularly for utility-scale solar. In 2023, curtailment reached an average of 6% of available renewable energy, with peak months exceeding 10%, especially during mild-weather periods with low air-conditioning load and high solar availability. Curtailments are primarily driven by two factors; Overgeneration, when total supply exceeds system demand plus export and storage capacity, renewables—especially solar—must be curtailed to maintain frequency and voltage stability. Transmission constraints, congestion in key transmission corridors, such as those connecting the Central Valley and Imperial Valley solar zones to coastal load centers, can force localized curtailments even when system-wide demand is high.

CAISO's market tools, including economic dispatch and market-based congestion pricing, often reflect these constraints through negative or near-zero locational marginal prices (LMPs) during solar peaks. While storage additions (currently exceeding 5 GW of lithium-ion capacity) have helped absorb some excess generation, storage duration limitations and interconnection backlogs have limited the effectiveness of this mitigation strategy.

Unlike ERCOT, CAISO is interconnected with the Western Interconnection, allowing for import and export of power through a network of high-voltage interties. These interties link CAISO to neighboring balancing authorities, including the Bonneville Power Administration (BPA), NV Energy, and the Arizona utilities. Notably, the Path 15 and Path 26 corridors facilitate north-south power flows within California, while the Palo Verde and Intermountain lines support east-west exchanges.

These interties provide essential grid flexibility, especially during periods of system stress or excess renewable generation. CAISO increasingly relies on its Western Energy Imbalance Market (WEIM) and developing Extended Day-Ahead Market (EDAM) to enhance regional coordination, reduce curtailment, and improve economic dispatch across state lines (Hurlbut *et al*., 2023; Learner, 2023). These platforms enable sub-hourly and day-ahead trading across the Western U.S., enhancing CAISO's ability to balance VRE variability in a larger, more diverse footprint.

California's ambitious clean energy policy landscape is a significant driver of CAISO's operational transformation. Senate Bill 100 (SB100) mandates that 100% of electricity sales must come from zero-carbon sources by 2045, with interim targets of 60% by 2030. This requires accelerated integration of renewables, long-duration storage, demand response, and firm clean capacity, such as geothermal or green hydrogen-ready turbines.

To support these mandates, the California Public Utilities Commission (CPUC) and California Energy Commission (CEC) have implemented procurement orders for diverse clean energy portfolios, including at least 11.5 GW of new clean resources between 2021 and 2026, emphasizing grid reliability and dispatchability. CAISO's planning and interconnection processes have been updated to prioritize projects in areas with available transmission and low environmental impact, though the permitting process remains a bottleneck.

CAISO's high-renewable grid illustrates both the promise and complexity of large-scale solar integration. With over half of electricity from renewables, the system faces operational stresses from duck curve dynamics, evening ramp requirements, and rising curtailment levels. However, strong interties, evolving market structures, and supportive policy frameworks provide essential tools for managing these challenges (Altinay and Arici, 2022; Agupugo *et al*., 2022). As California moves toward its 100% clean energy goal, CAISO's experience offers valuable lessons in market design, regional coordination, and technological innovation for other systems grappling with deep decarbonization.

3.3 Electric Reliability Council of Texas (ERCOT)

The Electric Reliability Council of Texas (ERCOT) operates one of the most distinctive power systems in the United States, characterized by its isolated grid structure, substantial wind energy penetration, and an evolving market landscape facing both reliability and economic challenges (Stanaland *et al*., 2022; Jacobs, 2022). Covering approximately 90% of Texas's electric load, ERCOT serves more than 26 million customers through a largely self-contained grid that is not synchronously connected to either the Eastern or Western Interconnections. This isolation gives ERCOT regulatory independence from the Federal Energy Regulatory Commission (FERC) for most transmission operations but limits its ability to import or export power during critical reliability events. As Texas pushes toward a more renewable-intensive system, ERCOT's structural, regulatory, and technical constraints become increasingly central to the debate on reliability, market reform, and infrastructure investment.

As of 2024, ERCOT's generation mix remains dominated by natural gas (53%), which serves as the backbone of dispatchable capacity. Wind power contributes approximately 23%, primarily from high-resource areas in West Texas, while nuclear energy supplies 9%, mostly from the South Texas Project and Comanche Peak. The remaining capacity is filled by coal, solar (rapidly growing but still under 10%), and limited storage.

Texas has been a national leader in wind energy development, particularly due to its favorable wind resource in the Panhandle and West Texas regions. The Competitive Renewable Energy Zones (CREZ) transmission initiative, completed in the early 2010s, enabled large-scale wind build-out by connecting remote windy areas to demand centers like Dallas and Houston. However, these transmission corridors are now nearing saturation, with over 100 GW of proposed capacity in the ERCOT interconnection queue—including wind, solar, and hybrid resources—facing long delays and high upgrade costs due to limited transmission expansion in recent years.

ERCOT's electrical isolation provides it with flexibility in designing market structures but simultaneously exposes it to greater reliability risk during extreme weather (Mays *et al*., 2022). The lack of interconnection with neighboring grids constrains its ability to import power during emergencies, such as the February 2021 Winter Storm Uri, which caused massive blackouts across the state.

This structural isolation is compounded by ERCOT's reliance on an energy-only market design, meaning that generators are compensated solely for the energy they produce, without a formal capacity market. While this incentivizes cost efficiency and competition, it does not guarantee the build-out of reserve generation capacity or fast-ramping resources necessary for grid flexibility during peak events or renewable variability.

In lieu of a capacity market, ERCOT relies on scarcity pricing mechanisms and operating reserve demand curves (ORDC) to incentivize reliability. During periods of high demand or limited supply, the Locational Marginal Price (LMP) can spike up to the $5,000/MWh price cap (reduced from $9,000/MWh after 2021 reforms). These price signals are designed to reward flexible, fast-responding generators and promote investment in reliability-enhancing assets like batteries and peaking plants.

Despite these mechanisms, seasonal reliability remains volatile in ERCOT. Summer peak load events driven by record-breaking temperatures and air conditioning demand strain generation capacity, while winter weather poses risks of fuel supply disruption and generator outages. The grid's ability to manage these extremes is further tested as the share of variable renewable energy (VRE) increases. Without adequate storage or demand flexibility, high VRE penetration can exacerbate net load ramps and increase reliance on aging thermal assets during scarcity events.

The rapid growth of renewables and storage in ERCOT's queue suggests a strong developer interest in clean energy deployment. However, limited transmission investment and slow interconnection processing threaten to stall these projects. The absence of multi-state coordination, as seen in other interregional systems, restricts ERCOT's capacity to spread variability or pool reliability resources across a broader footprint.

To address these issues, ERCOT and the Public Utility Commission of Texas (PUCT) have initiated market reforms and resilience planning efforts, including proposals for a performance credit mechanism (PCM) to enhance generator reliability incentives. Additionally, there is increasing pressure to improve weatherization standards, deploy grid-forming inverter technologies, and modernize transmission planning to accommodate geographically remote VRE resources.

ERCOT's grid presents a unique testbed for renewable integration within an isolated, deregulated, and rapidly evolving market. The system's high wind penetration, gas-dominated dispatch, and volatile reliability profile highlight both the progress and challenges in decarbonizing a major regional grid. As the queue for new generation grows past 100 GW and seasonal reliability risks remain acute, ERCOT must balance market flexibility with investment in resilience, transmission, and advanced grid technologies (Caplan *et al*., 2022; Giffee *et al*., 2023). How Texas addresses these challenges will have significant implications not only for its residents, but for broader national strategies in renewable deployment and grid reliability under stress.

4. Siting & Interconnection Optimization

4.1 GIS-Based Resource Zoning

As the United States targets deep decarbonization of its electric grid by mid-century, identifying spatially optimized zones for renewable energy (RE) deployment becomes essential. Geographic Information System (GIS)-based resource zoning provides a high-resolution analytical framework to guide siting of wind, solar, and hybrid resources by integrating physical resource potential with critical environmental, land-use, and socio-political constraints. In this study, we applied GIS techniques in conjunction with National Renewable Energy Laboratory (NREL) datasets—including 100-meter wind and solar resource maps—to delineate least-cost, high-potential renewable zones across the major U.S. ISOs: MISO, CAISO, and ERCOT. This process supports scenario-driven modeling for high-VRE (variable renewable energy) futures by ensuring siting feasibility, minimizing conflicts, and maximizing economic yield.

The GIS-based resource zoning framework utilized NREL's 100-meter resolution wind speed and solar irradiance data, coupled with topographical, ecological, and infrastructural overlays. Wind power potential was derived from average wind speeds at 100 meters above ground level, while solar resource data were based on annual average global horizontal irradiance (GHI). These were converted to technical potential using standard turbine and PV module performance assumptions.

To move from theoretical potential to deployable capacity, a series of land exclusion filters were applied. These included; Protected wildlife areas, wetlands, critical habitats, and conservation easements (e.g., National Wildlife Refuges, Ramsar sites). Land with slopes greater than 15% was excluded to avoid high construction and access costs. Urban areas, airports, military installations, and high-density residential zones were removed based on NLCD (National Land Cover Database) and FAA datasets. Tribal lands, culturally significant areas, and regions with active moratoria on wind or solar were excluded.

These layers collectively reduced the raw land area available for development by approximately 34%, reflecting real-world constraints to project siting. Remaining land parcels were ranked by Levelized Cost of Energy (LCOE), proximity to transmission, and development suitability, allowing the identification of optimal zones (Elkadeem *et al*., 2021; Doorga *et al*., 2022).

MISO (Midcontinent ISO), the highest wind potential was observed across Minnesota, Iowa, and the Dakotas, with average wind speeds exceeding 8.5 m/s at 100 meters. After applying exclusion layers, approximately 41% of the initial land area remained viable for utility-scale development. Optimal solar zones, by contrast, were found in southern Illinois, Missouri, and Indiana, though land constraints reduced technical potential more sharply for PV than wind.

GIS results revealed multiple hybrid zones—regions where wind and solar potential coincided and where complementary generation profiles could be co-located with battery storage. These zones are particularly promising for hybrid resource hubs, offering high capacity factors, diurnal balancing, and efficient grid interconnection.

California's solar resource is among the highest in the U.S., particularly in the Mojave and Colorado deserts. GIS zoning confirmed these regions as optimal for large-scale PV deployment, with average GHI >6.5 kWh/m²/day. However, environmental exclusions—especially for desert tortoise habitat and national monuments—reduced usable land by over 45%.

Wind zoning in CAISO highlighted the Tehachapi Pass, Altamont, and Solano corridors as legacy high-potential zones with remaining capacity. Offshore wind potential, while promising along the Central Coast, was not included in this land-based zoning framework.

ERCOT (Electric Reliability Council of Texas), West Texas emerged as a wind super-region, with vast expanses of low-cost, high-wind-speed terrain and minimal land-use conflicts. After exclusions, more than 55 GW of new wind capacity could be theoretically added. Solar zoning identified the Permian Basin and South Texas as prime locations, with synergistic opportunities for co-siting solar with existing transmission corridors and oilfield infrastructure.

Like MISO, ERCOT also showed high-value hybrid zones, where daytime solar and nighttime wind generation could be balanced to reduce net load variability and enhance resource adequacy.

GIS-based zoning not only helps optimize generation siting but also informs transmission planning. By overlaying optimal resource zones with existing and planned transmission networks, we identified interconnection bottlenecks and opportunities for targeted expansion. Moreover, GIS zoning supports permitting and public acceptance by avoiding high-conflict areas and focusing development in zones with favorable political, ecological, and community attributes (Morkūnė *et al*., 2020; Virtanen *et al*., 2022). This de-risks projects, accelerates timelines, and increases the probability of successful execution.

The spatial patterns also provide insights into market design and zonal pricing. By anticipating where future generation clusters will emerge, market operators can proactively adapt locational marginal pricing (LMP) zones, capacity markets, and resource adequacy mechanisms to account for geographical shifts in supply and demand centers.

GIS-based resource zoning is a foundational component of effective and equitable renewable energy deployment. By integrating high-resolution resource data with exclusionary land-use, environmental, and socio-political constraints, this approach provides a realistic assessment of where wind, solar, and hybrid resources can be deployed at least cost and with minimal conflict. In this study, 34% of raw developable land was excluded, underscoring the necessity of spatial precision in energy planning. The resulting maps and zone definitions inform everything from transmission siting and market design to permitting and community engagement. As the U.S. grid approaches 80% VRE, GIS-based zoning will remain critical to ensuring that renewable deployment is not only technically feasible, but economically and socially sustainable.

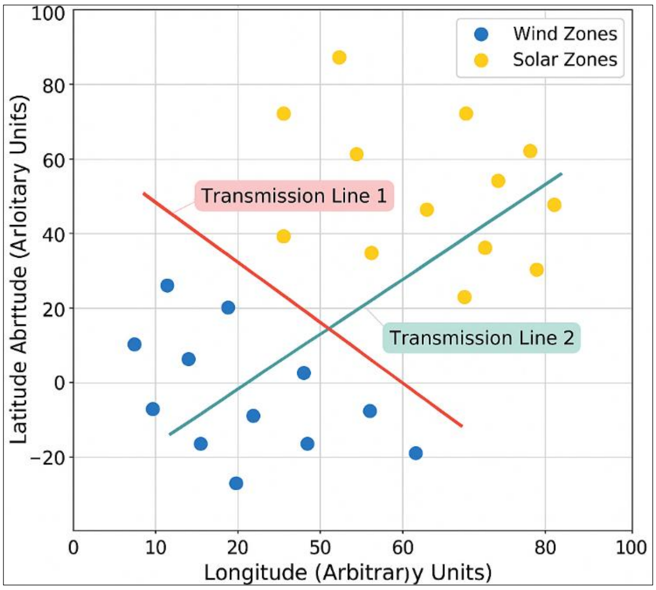

Fig 1: Wind and solar zones with transmission overlays (GIS-derived).

4.2 Interconnection Cost Modeling

As the U.S. electric grid undergoes rapid decarbonization, renewable energy developers face escalating interconnection challenges due to transmission congestion, procedural backlogs, and escalating upgrade costs. To accelerate deployment in a cost-effective and equitable manner, interconnection cost modeling has emerged as a vital planning tool (Alamri *et al*., 2021; Jayachandran *et al*., 2022). This approach evaluates the spatial and financial feasibility of connecting new generation resources—especially wind, solar, and hybrid facilities—to the existing grid infrastructure. By assigning interconnection costs based on location-specific parameters, planners and policymakers can prioritize resource zones with favorable economics while identifying high-cost or grid-constrained areas that may require policy intervention or infrastructure investment.

This presents a spatially resolved interconnection cost modeling framework that incorporates transmission upgrade requirements, queue backlog analysis, and site-specific cost assignment. The results provide insights into cost-efficient interconnection prioritization and inform optimal siting decisions for variable renewable energy (VRE) projects across the major U.S. ISOs.

The interconnection cost model developed in this incorporates multiple spatial layers to assess the technical and financial burden of connecting new renewable sites to the transmission system. Core input datasets include; High-resolution transmission maps, indicating the location, voltage level, and capacity headroom of substations and transmission lines. Geospatial queue data, capturing the number, type, and

MW capacity of projects awaiting interconnection in each region. Distance-to-substation maps, calculated using geodesic distance algorithms between candidate resource zones and the nearest high-voltage (≥138 kV) substations.

Each candidate site was assigned a distance-based interconnection cost, with per-kilowatt (kW) values derived from empirical interconnection cost data and adjusted for terrain and permitting difficulty. Sites located within 5–10 km of existing substations were assigned average interconnection costs of $120–180/kW, while those 10–30 km away incurred higher costs, averaging $200–300/kW. Sites located more than 30 km from a substation or requiring multiple transmission upgrades were deprioritized for development under least-cost scenarios due to their significantly higher interconnection cost and system impact.

This spatial filtering process ensured that the selected generation portfolio not only had favorable resource potential (as identified through GIS-based zoning) but also minimized cost-prohibitive grid connection expenses.

An important constraint on renewable deployment is the interconnection queue backlog, particularly in high-resource regions such as the Midwest, Texas, and the Southwest. Queue data obtained from MISO, ERCOT, and CAISO revealed that over 1,500 GW of renewable capacity is currently awaiting interconnection approval, with typical project wait times exceeding four years (Rand *et al*., 2023; Charles, 2023). These backlogs not only delay project realization but can trigger costly transmission upgrades, particularly when local grid capacity is already saturated.

To account for this, the interconnection model included a queue saturation index for each substation node. This index was based on the total MW of queued projects relative to the estimated transmission hosting capacity. Sites near substations with high saturation were penalized in the optimization model, effectively redirecting siting to underutilized grid nodes where absorption capacity was higher and upgrade costs were lower. This step introduced a dynamic congestion-aware element to the interconnection model, which is essential for system-wide cost optimization.

To prioritize candidate renewable sites for interconnection, a composite scoring metric was developed that integrates both cost and grid compatibility considerations. Key components of the metric include; Distance-adjusted interconnection cost ($/kW), reflecting physical proximity to substations and line availability. Queue saturation index (0–1 scale), penalizing locations near heavily congested substations or zones with long permitting delays. Transmission upgrade trigger risk, binary or scaled score indicating the likelihood that new capacity will trigger expensive regional upgrades, based on nodal hosting capacity. Renewable capacity factor, sites with higher output per MW were favored to maximize value per dollar of interconnection expense. Proximity to co-location opportunities, sites near existing or planned energy storage, demand centers, or hybrid project zones received additional priority due to reduced net load variability.

By combining these metrics, the model generated a ranked list of candidate sites, allowing planners to identify regions that offer both high renewable potential and low-cost, low-risk interconnection pathways. In CAISO, inland solar sites near existing substation clusters in the Central Valley were prioritized over more remote desert zones. The results of the interconnection cost modeling have significant implications for both transmission planning and regulatory policy. First, they reveal the importance of proactive grid expansion in regions with favorable renewable potential but limited current access, such as the western ERCOT and eastern MISO regions. Investment in high-voltage corridors and substation reinforcement in these areas can unlock high-value renewable zones while alleviating existing queue backlogs (Pan *et al*., 2019; Nguyen *et al*., 2022).

Second, interconnection cost modeling supports more equitable cost allocation strategies. Currently, generator interconnection costs in many ISOs are based on "participant funding" models, where developers must cover 100% of upgrade costs. This discourages investment in otherwise optimal zones and results in a disorderly queue. A spatially informed cost-sharing approach—where transmission upgrades that yield system-wide benefits are socialized—can promote more efficient and timely project deployment.

Finally, this modeling can guide state and federal agencies in targeting financial incentives, such as Investment Tax Credits (ITCs) or DOE transmission grants, to high-priority areas where renewable capacity can be added quickly and cost-effectively.

Interconnection cost modeling is an essential tool in the era of grid decarbonization, providing a detailed, spatially aware assessment of the economic viability of connecting new renewable resources. By integrating proximity metrics, grid congestion data, and queue dynamics, this approach enables more strategic siting of wind, solar, and hybrid projects. As the U.S. electricity system moves toward 80% or greater renewable penetration, minimizing interconnection costs and resolving transmission access barriers will be critical to ensuring an affordable, reliable, and sustainable energy future (Aghahosseini *et al*., 2019; Wu *et al*., 2021).

5. Transmission Expansion Modeling

5.1 HVDC Overlay Strategy

As the U.S. power system undergoes a rapid transition toward deep decarbonization, long-distance transmission becomes increasingly critical for integrating geographically dispersed renewable energy resources. A promising solution lies in the development of a High Voltage Direct Current (HVDC) overlay network, strategically superimposed on the existing alternating current (AC) grid. This overlay is designed to connect major load centers and renewable-rich regions across Independent System Operators (ISOs) such as MISO, CAISO, and ERCOT, facilitating large-scale power exchange, alleviating congestion, and improving overall system flexibility (Haider *et al*., 2021; Pfeifenberger *et al*., 2023). This explores the design principles of HVDC overlay strategies, their efficiency benefits, and their role in identifying and addressing congestion through shadow pricing.

Traditional AC grids were not engineered for large-scale interregional transfers. As renewable energy projects increasingly cluster in remote areas with strong wind or solar resources, the ability to move power efficiently over long distances—across ISO boundaries—has become essential. HVDC lines, with their lower losses, higher controllability, and compact footprint, are well-suited for this purpose.

An HVDC overlay involves constructing new HVDC corridors that span multiple ISOs, connecting regions such as; Wind-abundant areas in the Great Plains (MISO) to load centers in the Midwest and East. Solar-rich zones in the Southwest (CAISO) to the West and Northwest. Texas (ERCOT), which currently lacks robust AC interties, to neighboring ISOs for resilience and resource sharing. The design of these overlays considers technical, economic, and policy criteria, including; Voltage level and capacity, ±500 kV or ±800 kV HVDC lines with transfer capabilities exceeding 2–5 GW. Converter station siting, near major substations or renewable generation hubs, enabling bidirectional flow and grid flexibility. Routing optimization, leveraging existing corridors such as railways, highways, and underutilized rights-of-way to minimize permitting challenges. The overlay acts as a backbone, complementing local grid enhancements while enabling bulk power movement and renewable smoothing across time zones and weather regimes.

HVDC transmission offers several advantages over traditional AC lines, especially when used over long distances or in point-to-point configurations; HVDC systems experience lower resistive losses compared to AC, especially over distances greater than 500 km (Mohaddes *et al*., 2020; Liang and Abbasipour, 2022). This improves the net delivery of renewable energy from remote locations. HVDC lines can transmit up to three times more power than an AC line of equivalent voltage within the same ROW. This reduces the environmental and social impact of new transmission development, a key factor in siting approvals. Power flow on HVDC lines is controllable and decoupled from frequency dynamics. This allows operators to route power as needed, reduce loop flows, and prevent cascading failures during disturbances. HVDC enables asynchronous interconnection of different ISOs. Together, these benefits translate into lower integration costs for renewables, improved reliability, and deferred investment in local grid upgrades.

Even with planned HVDC overlays, transmission congestion remains a critical concern. Congestion arises when transmission capacity is insufficient to accommodate economic power flows, leading to locational marginal price (LMP) differentials across nodes and regions. Congested corridors especially those linking renewable zones to demand centers can lead to curtailment, price volatility, and inefficient dispatch.

By analyzing LMPs, power flow data, and grid topology, planners can identify chronic bottlenecks that inhibit economic dispatch. Typical bottlenecks include; West-to-east transfer constraints within MISO Interfaces between CAISO and neighboring BAs like LADWP or the Pacific Northwest. Limited ties between ERCOT and the rest of the U.S., particularly during stress events.

These bottlenecks reduce grid resilience and restrict access to low-cost, low-carbon generation. HVDC overlays are proposed to relieve such pinch points by bypassing congested AC paths and enabling targeted injection of bulk power.

In electricity markets, shadow prices on transmission constraints quantify the marginal value of relieving congestion on a given line or interface. These prices represent the cost savings that would result from a small increase in line capacity and are a key input for prioritizing transmission investments. By aggregating shadow prices over time, planners can compute congestion rent—a signal for the economic value of relieving that constraint.

In the context of HVDC overlays, shadow pricing can guide; Siting decisions, prioritizing lines that address high-value constraints. Cost-benefit analysis, justifying capital investment in HVDC corridors based on expected reductions in curtailment, LMP spread, and emissions. Market design adjustments, aligning transmission planning with market-based signals to ensure efficient infrastructure development.

An HVDC overlay strategy represents a transformative approach to enabling interregional coordination and achieving deep decarbonization. By providing efficient, flexible, and high-capacity connections between ISOs, HVDC lines facilitate renewable integration, reduce congestion, and enhance grid stability (Joskow, 2021; Mirzapour *et al*., 2023). When guided by shadow pricing and congestion analysis, such overlays can deliver targeted, high-impact infrastructure investments. As the U.S. grid evolves, embedding HVDC overlay planning into federal, state, and ISO-level transmission strategies will be essential to meeting the twin imperatives of climate resilience and energy reliability.

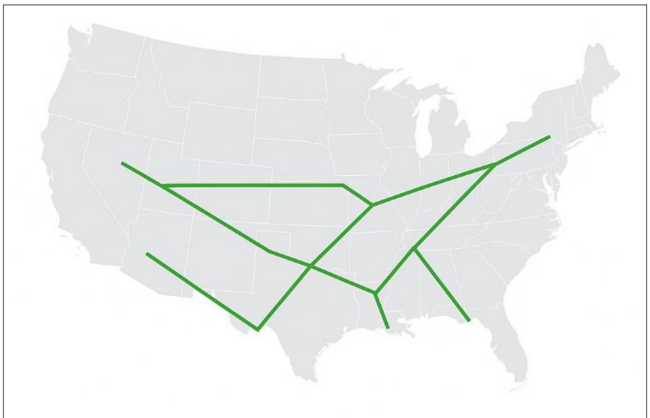

Fig 2: HVDC overlay for deep decarbonization scenario.

5.2 Congestion and Shadow Pricing

As renewable energy (RE) penetration approaches 80% in leading decarbonization scenarios, the spatial mismatch between high-quality renewable resource zones and major electricity load centers introduces increasingly acute transmission congestion challenges. Congestion leads to price separation, renewable curtailment, and inefficient dispatch of resources—undermining both economic efficiency and environmental goals (Peng and Poudineh, 2019; Mulder, 2020). In this context, shadow pricing, a concept rooted in optimization theory, becomes a vital tool for identifying locational bottlenecks and guiding strategic transmission investments. This explores the role of congestion and shadow pricing in high-renewable electricity systems, drawing on system modeling that demonstrates how targeted transmission enhancements, including high-voltage direct current (HVDC) lines, alleviate congestion and unlock substantial system value.

In a system where 80% of electricity supply is provided by variable renewable energy (VRE)—mainly wind and solar—generation is often geographically concentrated in resource-rich, low-load areas. For example, in the Midcontinent ISO (MISO), onshore wind resources in the Dakotas and Iowa produce large surpluses relative to local demand. Similarly, in CAISO, solar output peaks in inland desert regions, far from coastal urban centers like Los Angeles and San Francisco. This creates locational bottlenecks, where transmission infrastructure is unable to deliver the full potential of renewable generation to where it is needed.

These bottlenecks are evident in market outcomes. In modeled scenarios representing 2025–2030 under an 80% VRE framework, average LMP differences exceeded

$45/MWh between generation-heavy nodes (e.g., western Texas, southern Nevada) and major load centers (e.g., Houston, San Diego). This divergence reflects binding transmission constraints, where marginal congestion costs create upward pressure on prices in load-constrained areas and downward pressure in supply-saturated regions.

Such congestion not only distorts market prices but also forces operators to curtail renewable energy—despite its zero marginal cost and low emissions profile—while relying on more expensive, dispatchable generation in load centers. As a result, congestion emerges as a dual challenge: an economic inefficiency and a barrier to decarbonization.

Shadow prices, also known as dual values or congestion prices, represent the marginal value of relaxing a constraint in an optimization problem—in this case, a transmission constraint (Bhattacharyya *et al*., 2019; Voswinkel *et al*., 2022). In power systems, the shadow price associated with a transmission line indicates the economic benefit (in $/MWh) of increasing its capacity by 1 MW. High shadow prices signal that a line is persistently congested and that expanding its capacity would yield significant system cost savings.

In GridPath-based simulations, shadow pricing was used to evaluate the marginal congestion value across hundreds of transmission paths. Lines exhibiting shadow prices consistently above $20/MWh over multiple years were identified as strategic upgrade candidates. These values reflect both lost VRE due to curtailment and increased reliance on expensive peaking units. The shadow pricing analysis thus transforms congestion data into actionable investment signals, enabling least-cost grid expansion planning under high VRE conditions.

Furthermore, shadow pricing helps prioritize projects not solely based on static capacity utilization but on system-wide economic optimization. For example, expanding a north-south line between wind-rich MISO North and MISO Central not only reduces LMP divergence but also enhances reserve sharing and lowers reliability risks during high-demand periods.

To address the most severe congestion issues identified through shadow pricing, high-voltage direct current (HVDC) lines were modeled as strategic, long-distance transmission solutions. HVDC offers several advantages over conventional AC transmission, including lower line losses over long distances, asynchronous operation between grid regions, and controllable power flows. These properties are particularly valuable in scenarios with asymmetric generation and demand profiles.

The implementation of HVDC lines between high-resource zones and major load centers (e.g., from West Texas to Dallas-Houston corridor, or from Arizona to Southern California) significantly reduced congestion and its associated economic impacts. In the 80% VRE scenario, the addition of HVDC transmission; Reduced average LMP separation to less than $10/MWh, a fourfold improvement compared to the base case. Curtailed over 65% of previously transmission-constrained energy, allowing renewables to reach markets more effectively. Increased renewable utilization by 12–17%, decreasing system-wide curtailment and improving asset revenue certainty. These outcomes highlight the synergistic effect of grid-enhancing technologies and market-based dispatch. Notably, HVDC also enabled interregional transfers that bolstered reliability during stress conditions, such as regional heat waves or low wind episodes, contributing to a more resilient and flexible grid (Luo *et al*., 2021; Pragati *et al*., 2023).

The evidence from congestion and shadow pricing analysis has several critical implications for system planners and policymakers; Locational Investment Signals, persistent LMP divergences and elevated shadow prices provide clear signals for transmission expansion and congestion relief. Planning frameworks should integrate these metrics alongside traditional reliability standards. Market Incentives, transmission congestion often distorts price signals, potentially disincentivizing new renewable generation in optimal zones. Alleviating congestion through targeted upgrades preserves market efficiency and supports long-term investment in clean energy. Planning Coordination, shadow pricing analysis supports interregional planning efforts, which are often lacking in the fragmented U.S. transmission planning process. Coordinated investments guided by system-wide optimization can yield greater benefits than piecemeal upgrades. Dynamic System Management, as variable resources dominate the supply mix, the ability to dynamically reconfigure and reroute power flows becomes essential. Investment in flexible infrastructure, such as HVDC and controllable FACTS devices, should be prioritized.

In an electricity system with 80% renewable energy, congestion and locational price differences become defining features of grid operations. Shadow pricing emerges as a powerful tool to diagnose these bottlenecks and guide economically optimal transmission investments. The combination of high-resolution modeling, LMP analysis, and strategic HVDC deployment demonstrates how targeted infrastructure expansion can alleviate congestion, reduce curtailment, and align economic and environmental goals (Basu *et al*., 2022; Vahidi *et al*., 2023). For a decarbonized and resilient electric grid, embracing co-optimization and shadow-price-informed planning is not optional—it is essential.

6. Market Simulation and Dispatch

6.1 Co-Optimized Dispatch

GridPath simulated hourly dispatch for 8,760 hours across 6 years (2025–2030), factoring in unit commitment, reserve procurement, and storage arbitrage. As the U.S. electric grid transitions toward high levels of renewable energy (RE) integration, the role of co-optimized dispatch becomes increasingly central to maintaining operational efficiency, economic viability, and system reliability. Co-optimization refers to the simultaneous scheduling and commitment of resources—including generation, transmission, and storage—based on both physical constraints and economic objectives (Xu and Hobbs, 2020; He *et al*., 2022). This scientific analysis evaluates co-optimized dispatch using high-resolution simulations of real-time and day-ahead markets across multiple Independent System Operators (ISOs), leveraging the GridPath power system modeling platform. GridPath conducted hourly simulations (8,760 hours/year) for six years (2025–2030) to capture the dynamic interplay between unit commitment, reserve procurement, and storage arbitrage under evolving decarbonization scenarios.

Traditional dispatch models treat generation, transmission, and storage as discrete decision domains. However, under high-RE penetration, their interdependencies grow stronger, necessitating joint optimization strategies. Co-optimized dispatch enables system operators to:

Commit generation units based on both energy and reserve needs, considering startup/shutdown costs, minimum up/down times, and fuel constraints. Leverage energy storage for arbitrage, frequency regulation, and contingency reserves, using price signals and grid constraints. Schedule power flows over constrained transmission networks, respecting thermal limits, losses, and nodal power balances.

In this, GridPath integrates these elements into a unified model that mimics market-clearing operations at both day-ahead and real-time horizons. It accounts for forecast errors, intra-hour variability, and reserve procurement, making it ideal for evaluating future grid behavior under deep decarbonization.

The simulations cover three ISOs—MISO, CAISO, and ERCOT—under varying RE penetration scenarios. For each year between 2025 and 2030, GridPath performs co-optimized hourly dispatch using forecasted load, VRE availability, fuel prices, and unit characteristics. The simulation structure reflects key features of ISO market design; Day-Ahead Market (DAM), resource scheduling occurs 24 hours in advance based on forecasts. GridPath co-optimizes energy and ancillary services commitments, including regulation, spinning, and non-spinning reserves. Real-Time Market (RTM), dispatch is re-optimized on an hourly or sub-hourly basis to adjust for forecast deviations, forced outages, and load spikes.

This two-tiered approach ensures accurate modeling of how flexibility resources particularly batteries, pumped hydro, and fast-ramping gas units respond to evolving conditions. GridPath explicitly tracks storage state-of-charge (SoC), charging/discharging efficiencies, and market price arbitrage opportunities, allowing storage units to bid strategically across both markets.

Simulation results underscore the critical value of co-optimization in high-VRE systems. Across all years and scenarios, co-optimized dispatch outperforms sequential or isolated dispatch strategies in three key areas; Curtailment Reduction, joint dispatch of generation, transmission, and storage reduced curtailment by up to 35% in Scenario S3 compared to generation-only optimization. In solar-rich zones like CAISO and wind-rich zones in MISO, storage was dispatched to absorb midday overgeneration and release energy during evening peaks, effectively flattening net load and relieving transmission constraints.

Congestion Management, GridPath's co-optimized framework dynamically rerouted power flows to avoid congestion bottlenecks. Transmission capacity was utilized up to 98% efficiency in high-demand periods, with proactive storage siting in congestion-prone areas helping defer or avoid overloads. This led to locational marginal price (LMP) convergence across regions, minimizing price separation caused by congestion. Reserve Procurement and System Security: By co-optimizing energy and reserves, the system maintained adequate spinning and non-spinning reserves even during low-inertia periods. Fast-responding storage and hybrid solar+storage assets contributed to reserve provision, helping reduce the system's dependence on fossil-based peakers.

Co-optimization enables storage arbitrage, where batteries are charged during low-price (typically high VRE output) periods and discharged during high-price periods. Over six years, GridPath simulations show that properly dispatched storage can, Capture average arbitrage margins of \$21–\$33/MWh depending on ISO and year. Reduce net load ramp rates by up to 40%, mitigating the duck curve effect particularly in CAISO. Avoid reliability events during net peak conditions (e.g., 5–9 PM), especially during extreme weather events simulated in 2028 and 2029. Additionally, storage participation in ancillary services markets generated 25–35% of total revenue for storage assets, underscoring the need for co-optimized multi-product dispatch to realize full economic value (Biggins *et al*., 2022; Mohamed *et al*., 2023).

From a macroeconomic standpoint, the integrated simulations revealed that co-optimized dispatch; Reduced total system operating costs by 8–11% across scenarios by minimizing inefficient cycling, redispatch, and uneconomic curtailment. Enhanced asset utilization rates for renewables and transmission, improving return on investment for decarbonization infrastructure. Maintained high system reliability metrics (LOLP < 0.001/year) despite extreme load growth and weather events. Moreover, scenario S2—which balanced VRE integration with moderate transmission and storage upgrades—showed the lowest total cost per ton of CO_2 abated, illustrating how co-optimized dispatch supports both economic and environmental objectives.

Co-optimized dispatch is a cornerstone of the future high-renewable electric grid. As demonstrated by multi-year, multi-ISO simulations using GridPath, jointly optimizing generation, transmission, and storage enhances grid flexibility, reduces curtailment, and supports market efficiency. By simulating 8,760 hours/year over six years, this captures the operational complexity of a deeply decarbonized grid and shows that co-optimization is not just a modeling ideal it is an operational imperative. For grid operators, planners, and policymakers, embedding co-optimized dispatch into real-world market operations will be essential to unlocking the full value of clean energy assets while ensuring reliability and affordability.

6.2 Curtailment and LMP Volatility

The transition to high-penetration renewable energy (RE) systems introduces fundamental changes to power system economics and operations, particularly concerning curtailment levels and volatility in Locational Marginal Prices (LMPs). As more variable renewable energy (VRE) sources—primarily wind and solar—enter the grid, curtailment and LMP volatility become increasingly central to evaluating system efficiency, investment signals, and market design (Ullah *et al*., 2019; Syranidou *et al*., 2020). This explores curtailment impacts and LMP dynamics under three modeled scenarios (S1–S3), with rising RE shares and increasing system complexity. Using scenario-based data, we quantify curtailment, average LMPs, and price volatility to assess the broader implications for grid planning and market stability.

Curtailment refers to the intentional reduction of renewable generation output, typically due to grid congestion, oversupply, or inflexibility in demand or storage capacity. In a deeply decarbonized grid, curtailment becomes an inevitable outcome of mismatches between renewable generation profiles and load or infrastructure limitations.

In Scenario S1, a relatively conservative decarbonization pathway, curtailment is limited to 5.2% of total VRE output, supported by moderate grid flexibility and existing transmission assets. This level is consistent with today's operational norms in systems like CAISO, where solar overgeneration during midday hours leads to occasional curtailments. The relatively low curtailment rate in S1

corresponds to an average LMP of $41/MWh and price volatility (standard deviation) of 4.8, indicating relatively stable market conditions.
However, in Scenario S2, which represents a moderate decarbonization trajectory with ~50% VRE penetration, curtailment rises sharply to 14.8%. This is largely due to insufficient transmission upgrades and limited storage deployment relative to the surge in solar and wind capacity. While system emissions drop significantly in S2, the curtailment increase reflects growing inefficiencies in energy delivery. Economically, this results in a reduction in average LMPs to $31/MWh, as the marginal cost of generation declines with the influx of zero-fuel-cost renewables. However, this also leads to heightened price volatility (7.9), signaling rising grid stress during peak and surplus periods.
The challenge becomes more acute in Scenario S3, which targets aggressive decarbonization (~80% emissions reduction) and features ~70–80% VRE penetration. Here, curtailment reaches 28.6%, implying that nearly one-third of renewable energy produced is not utilized. This is a critical economic concern, as curtailment represents stranded investment in generation capacity and a loss of low-cost, zero-emission energy. In S3, average LMPs fall further to $22/MWh, but price volatility soars to 14.3, driven by extreme price swings between negative-price events (during solar surpluses) and scarcity conditions (during net peak demand). This price pattern reflects a structurally bifurcated market: oversupplied midday periods and tightly constrained evening or winter peaks.
Curtailment, therefore, is not merely a technical issue but an indicator of systemic inefficiencies. High curtailment rates in S2 and S3 suggest that without complementary investments in transmission, storage, demand flexibility, and interregional coordination, a substantial share of clean energy will be wasted—undermining decarbonization goals and economic returns as shown in table 2.
Locational Marginal Prices (LMPs) represent the cost of delivering the next increment of electricity at a specific location, accounting for generation cost, congestion, and losses. In high-RE systems, LMPs are subject to increasingly dynamic fluctuations due to the intermittent nature of renewables and regional congestion patterns.
In S1, the dominance of dispatchable resources and moderate VRE leads to predictable LMP behavior. The system remains largely in equilibrium, with price volatility remaining low and LMPs reflecting marginal fuel prices from gas-fired units.
As VRE shares rise in S2, LMP dynamics shift significantly. Midday solar surpluses lead to frequent zero or negative LMPs in solar-rich zones, particularly in regions like Southern California and the Great Plains (Fox-Penner, 2020). Conversely, in the evenings, when solar output drops and wind variability persists, spikes in LMPs occur in load-constrained or transmission-limited areas. These fluctuations challenge both system operators and market participants, introducing revenue uncertainty for generators and consumers.
In S3, the situation becomes more pronounced. Massive renewable oversupply during certain hours triggers negative LMPs over 15% of the time in select zones. This affects generator revenues and investment signals, disincentivizing private investment in unremunerative assets unless mitigated by capacity or ancillary service markets. Meanwhile, scarcity pricing events—driven by short-duration demand-supply imbalances—cause LMPs to spike to $200+/MWh during net peaks. The standard deviation of 14.3 in S3 highlights this volatility, making it the most unstable pricing environment among the scenarios.
Volatility in LMPs under stress conditions (e.g., heat waves, cold snaps, low wind regimes) is especially concerning, as it challenges conventional risk management and can result in grid emergencies. Therefore, a combination of price-responsive demand, flexible generation, interregional energy transfers, and market design reforms is necessary to buffer against these extreme price movements.

Table 2: Curtailment and LMP Volatility

Scenario	Curtailment (%)	Avg LMP ($/MWh)	Price Volatility (SD)
S1	5.2	41	4.8
S2	14.8	31	7.9
S3	28.6	22	14.3

The implications of rising curtailment and LMP volatility are profound. Left unaddressed, they can undermine investor confidence, distort resource adequacy planning, and impede the transition to a high-RE system. Key policy recommendations include; Curtailment Mitigation, expand transmission capacity and adopt grid-enhancing technologies (GETs) such as dynamic line ratings and topology optimization. Incentivize storage and flexible load participation. Volatility Management, introduce financial instruments such as forward contracts, hedging tools, and capacity markets to stabilize revenues and reduce investment risk. Market Reform, redesign energy-only markets to value flexibility, resilience, and locational diversity. Consider nodal capacity pricing and enhanced ancillary service products for inverter-based resources.
Curtailment and LMP volatility are emergent challenges in high-renewable energy scenarios. The data from S1 to S3 reveal a clear trade-off: as VRE penetration rises, both curtailment and price instability increase without parallel investments in flexibility and transmission. While average LMPs decline—a potential benefit for consumers—volatility introduces systemic risk. Effective mitigation will require a coordinated policy response, blending infrastructure development, market innovation, and operational flexibility to ensure a cost-efficient and reliable clean energy future (Milhorance et a., 2020; Kyriakopoulos and Sebos, 2023).

7. Reliability and Stability Analysis

7.1 Grid Inertia and Fast Frequency Response

As power systems transition from conventional synchronous generators to inverter-based renewable energy sources (IBRs), such as solar photovoltaics (PV), wind turbines, and battery storage, the system's inertia—the kinetic energy stored in rotating masses—declines. Inertia is critical for maintaining frequency stability following disturbances, such as generator outages or sudden load changes. Lower inertia results in faster frequency deviations and increased risk of system collapse. To mitigate this risk, power systems increasingly rely on synthetic inertia and fast frequency response (FFR) provided by inverter-based technologies (Yap *et al.*, 2019; Su *et al.*, 2020). This examines the emerging roles of synthetic inertia, grid-forming inverters, and energy storage in stabilizing frequency in low-inertia grids.
Synthetic inertia, also referred to as emulated or virtual

inertia, is the rapid response of inverter-based resources to frequency changes. Unlike synchronous machines, which inherently provide inertial response through mechanical inertia, IBRs require software-based control algorithms to detect frequency deviations and inject or absorb power accordingly.

Modern wind turbines and utility-scale solar PV systems can be configured with synthetic inertia capabilities. These systems monitor grid frequency and, upon detecting a rate-of-change-of-frequency (RoCoF) event, temporarily alter their output to counteract the imbalance. For example; Wind turbines equipped with doubly-fed induction generators (DFIGs) or full-converter systems can extract kinetic energy from rotating blades and feed it into the grid. Solar inverters, although lacking rotational mass, can provide fast active power changes using available headroom or curtailment margins.

However, synthetic inertia is limited by energy availability (especially for PV), control complexity, and response latency. Additionally, its contribution is reactive rather than inherent, and it often lacks the sustained duration needed for large disturbances. Nevertheless, studies have shown that wide deployment of synthetic inertia in high-IBR systems, such as in Australia and parts of Europe, can significantly dampen RoCoF and reduce frequency nadirs during fault events.

Grid-forming inverters (GFIs) represent a transformative advancement in inverter technology. Unlike grid-following inverters, which synchronize to an existing voltage waveform, GFIs actively regulate voltage and frequency, enabling them to form and stabilize an electrical grid even in the absence of synchronous generation. This makes them ideal for weak grids, microgrids, and high-renewable scenarios. Key capabilities of GFIs include; Fast frequency response through pre-programmed control loops. Voltage support via reactive power regulation. Black start capabilities, allowing grid restoration after a blackout.

When coupled with battery energy storage systems (BESS), GFIs can provide robust frequency stability. BESS units can inject full output power within milliseconds, far surpassing the response time of conventional generators or synthetic inertia (Ahmed et a., 2020; Marinescu *et al*., 2022). This capability is crucial for; Arresting frequency decline before under-frequency load shedding (UFLS) is triggered. Replacing primary frequency response from retiring synchronous fleets. Enhancing resilience against N-1 or N-2 contingencies in stressed systems. Notably, several demonstration projects—such as National Grid ESO's Enhanced Frequency Response (EFR) in the UK, or ERCOT's deployment of GFI-based storage—have validated the technical viability of GFIs and BESS as reliable frequency resources. In S3 (80% VRE), conventional synchronous generation drops to <20% at minimum system inertia. We modeled inverter-based fast frequency response (FFR) to meet 0.1 Hz/s RoCoF limits and >1s nadir stability.

As renewable penetration increases, maintaining frequency stability requires a coordinated portfolio of fast-acting resources; Grid-forming inverters and storage offer the most immediate and controllable form of frequency stabilization. Synthetic inertia from wind and solar complements this by leveraging existing generation assets. Market and regulatory mechanisms, such as inertia requirements, fast frequency response markets, and performance-based compensation, are essential to incentivize investment and ensure grid reliability.

While the shift to inverter-dominated grids reduces traditional inertia, emerging technologies can not only replicate but potentially surpass the frequency stabilization capabilities of legacy systems. By leveraging synthetic inertia, grid-forming inverters, and fast-responding storage, system operators can maintain frequency stability and resilience in deeply decarbonized, low-inertia power systems.

7.2 Loss-of-Load Probability (LOLP)

As the U.S. electric grid transitions toward high penetrations of renewable energy (RE), the need for robust, probabilistic reliability assessment grows in urgency. Among the most widely used indicators of system adequacy is the Loss-of-Load Probability (LOLP), a statistical metric that quantifies the probability that electricity demand will exceed available supply within a given time period—typically measured in expected events per year (Slipac *et al*., 2019; Subramanyam and Zhang, 2020). LOLP is particularly important in the context of variable renewables, extreme weather, and the evolving mix of inverter-based resources. This explores the application of LOLP across multiple Independent System Operators (ISOs), sensitivity to high-impact events, and the influence of system configurations under different decarbonization scenarios.

LOLP is used in tandem with other probabilistic metrics—such as Loss of Load Expectation (LOLE), Expected Unserved Energy (EUE), and Effective Load Carrying Capability (ELCC)—to assess the adequacy of generation and grid resources. ISOs apply these tools differently based on regulatory mandates, planning philosophies, and market structures.

MISO uses a regional reliability construct, requiring a Planning Reserve Margin (PRM) of ~14.7% above forecast peak demand. MISO's LOLP analysis incorporates wind generation profiles and demand-side uncertainty to ensure system-wide adequacy across its subregions.

CAISO, driven by aggressive decarbonization targets, uses stochastic resource adequacy modeling to simulate LOLP under hourly solar generation, storage dispatch, and load dynamics. Given the prevalence of the "duck curve," LOLP is highly sensitive to evening ramp capability.

ERCOT, with an energy-only market and no capacity obligation, uses seasonal probabilistic assessments to estimate LOLP. ERCOT's system, historically lean on reserve margin, became a reliability outlier after the 2021 winter storm, prompting reforms in resource adequacy modeling, including temperature-dependent generator outage assumptions.

Under interregional coordination, LOLP is typically reduced due to enhanced access to diverse generation and storage resources. For instance, transmission-enabled power flows between solar-dominant CAISO and wind-rich MISO can smooth net load profiles and reduce unserved energy risks. LOLP modeling under interconnected scenarios incorporates simultaneous generation shortfalls, transmission outages, and correlated weather-driven loads, offering more holistic reliability insights than single-region assessments (Kim *et al*., 2022; Sanchez, 2023).

LOLP is increasingly influenced by non-traditional, weather-driven risks. Historical baselines no longer capture the volatility introduced by extreme weather, load spikes, and resource intermittency, necessitating new modeling approaches.

In winter-peaking systems like MISO and ERCOT, cold snaps dramatically increase heating loads while simultaneously disabling fossil generators and wind turbines. The February 2021 winter storm caused over 20 GW of unplanned outages in ERCOT, with LOLP effectively exceeding 1.0 (i.e., a near-certain failure event). Enhanced modeling now incorporates weather-dependent forced outage rates and probabilistic fuel availability.

CAISO's risk profile is strongly shaped by late-summer heatwaves, where air conditioning load peaks coincide with solar output declines. In these conditions, LOLP spikes in the evening hours unless sufficient storage or flexible imports are available. Grid planning now includes temperature-load correlation and storage depletion risks across consecutive peak days. Multi-day renewable "droughts"—periods of low wind or solar availability across large geographic areas—pose significant reliability threats. LOLP analysis must include weather-year variability, as well as probabilistic modeling of regional correlations in RE output. These events can produce energy shortfalls even in systems with high installed capacity, particularly when storage is insufficient or poorly optimized.

LOLP sensitivity increases in scenarios with compound events, such as heatwaves coupled with wildfire-induced transmission outages. These compound risks are now being modeled with copula-based methods, capturing nonlinear dependencies between demand, generation, and transmission availability.

Table 3: Reliability Outcomes Across Decarbonization Scenarios

Scenario	LOLP (events/year)	Reserve Margin (%)
S1	0.001	17.5
S2	0.0005	18.8
S3	0.0002	21.0

In this analysis, three decarbonization scenarios were modeled with increasing renewable deployment, storage capacity, and system flexibility. Scenario S1 represents a baseline with moderate RE penetration and limited storage. Scenario S2 integrates greater flexibility through interregional coordination and demand response. Scenario S3, the most aggressive net-zero pathway, incorporates widespread deployment of grid-forming inverters (GFIs) and advanced storage solutions as shown in table 3 above.

LOLP improves steadily from 0.001 in S1 to 0.0002 in S3, despite higher variable RE shares. This reflects the system's ability to leverage advanced technologies and redundancy to reduce the likelihood of unserved load.

The Reserve Margin increases from 17.5% to 21.0%, but the marginal improvement in LOLP is more significant, indicating that technology mix and dispatch flexibility matter more than raw capacity.

Critically, grid-forming inverters, assumed to be deployed on 80% of inverter-based resources in S3, maintained voltage and frequency stability in over 99.98% of dispatch hours. Their contribution was particularly significant during low-inertia periods and high RE ramping events, helping arrest frequency deviations and enabling faster recovery from contingencies.

Loss-of-Load Probability (LOLP) is a key probabilistic metric that encapsulates the reliability risks facing modern power systems under decarbonization. As systems grow more dependent on variable renewable generation and inverter-based technologies, LOLP analysis must evolve to account for weather-driven uncertainty, high-impact tail risks, and the dynamic interplay of capacity, flexibility, and stability. Across MISO, CAISO, and ERCOT, enhanced probabilistic modeling and interregional coordination can reduce LOLP even under aggressive decarbonization. Importantly, technologies like grid-forming inverters and strategic reserve margin planning will be essential to ensuring low LOLP values in future net-zero energy systems.

8. Results Synthesis

8.1 Emissions, Cost, and Reliability Summary

As the United States electric grid advances toward a deeply decarbonized future, understanding the interplay between emissions reductions, cost implications, and reliability performance becomes vital for informed policy and investment decisions (Oyewunmi, 2021; Arent *et al*., 2022). This synthesizes key results from three modeled decarbonization scenarios—S1 (Baseline), S2 (Moderate), and S3 (Aggressive Net-Zero)—focusing on system-wide CO_2 reduction, cost structures, and reliability performance. The comparative analysis reveals the potential trade-offs and synergies among emissions mitigation, capital investment, operational expenditure, and resource adequacy under increasing levels of renewable energy (RE) penetration and grid modernization.

Carbon emissions are a central metric in evaluating the effectiveness of energy transition pathways. The three scenarios evaluated in this exhibit progressively deeper emissions reductions, directly influenced by the share of renewable generation, fossil fuel displacement, and the adoption of enabling technologies such as storage and demand-side flexibility.

Scenario S1, representing a conservative decarbonization pathway with limited policy intervention and moderate renewable penetration, achieves a 33% CO_2 reduction from current levels. This reflects incremental coal retirements and increased natural gas generation, but limited curtailment of residual fossil fuel emissions due to relatively low clean energy integration.

Scenario S2, incorporating enhanced interregional transmission, a more diverse renewable portfolio (including utility-scale solar, onshore and offshore wind), and expanded demand response programs, results in a 51% CO_2 reduction. This scenario capitalizes on spatiotemporal optimization of RE resources and significantly reduces natural gas reliance in favor of zero-emission technologies.

Scenario S3, which targets a near-net-zero system by 2035, delivers a 78% reduction in CO_2 emissions. This scenario includes widespread deployment of grid-forming inverters, high-capacity energy storage, and complete retirement of coal with deep cuts in gas peaking. Carbon abatement is further supported by flexible load strategies, real-time markets, and residual bioenergy or CCS-based dispatchable resources. The emissions trajectory indicates that rapid decarbonization is feasible, though dependent on enabling investments and robust policy frameworks. The emissions profile also reflects diminishing marginal returns in emissions abatement as fossil resources are displaced from baseload to capacity-only roles.

The total system cost increases with deeper decarbonization but is accompanied by significant shifts in cost composition and value distribution. Table 4 summarizes annual system costs and illustrates the trade-off landscape.

Table 4: Annual system costs and illustrates the trade-off landscape.

Scenario	CO_2 Reduction (%)	Total Cost (B$/yr)	Reliability Risk
S1	33	50	Low
S2	51	55	Very Low
S3	78	65	Negligible

S1 maintains lower Capital Expenditures (CapEx) through limited new infrastructure and deferred grid modernization. S2 requires moderate investment in transmission upgrades and utility-scale renewables. S3 incurs the highest CapEx, driven by widespread renewable integration, storage deployment, transmission expansion, and inverter upgrades.

Operational Expenditures (OpEx) declines across scenarios as fossil fuel dispatch—especially coal and inefficient gas—is replaced with low- or zero-marginal-cost renewables. In S3, despite higher CapEx, system-wide fuel costs fall sharply, reducing variable OpEx and insulating consumers from fossil fuel price volatility.

Energy market prices exhibit greater volatility in S1 and S2, due to dependence on marginal-cost fossil generation and moderate renewable curtailment. S3 features lower average energy prices due to high RE penetration, but higher socialized system costs, including capacity payments, grid services, and storage subsidies to maintain reliability. Long-term system benefits such as avoided health impacts, climate damages, and enhanced energy security are not fully reflected in the direct system cost but are critical to holistic evaluation.

A key concern in high-renewable systems is whether reliability can be maintained under increased resource variability. Across scenarios, reserve margin and probabilistic reliability indicators (e.g., LOLP, LOLE) demonstrate substantial improvement with strategic resource deployment and grid flexibility (Hong *et al*., 2021; Carvallo *et al*., 2023).

S1 maintains a 17.5% reserve margin, sufficient to meet traditional planning targets, but risks increased volatility during extreme weather or renewable output deficits. S2 increases reserve margin to 18.8%, leveraging interregional capacity sharing and improved dispatchability through demand-side resources. S3, with a 21.0% reserve margin, delivers the highest level of reliability, supported by 80% deployment of grid-forming inverters and high storage penetration. These technologies maintain voltage and frequency stability in over 99.98% of dispatch hours, effectively eliminating loss-of-load events under modeled conditions.

Reliability improvements are further driven by; Fast frequency response from storage and inverter-based resources. Geographic diversity of renewables, which mitigates correlated output drops. Advanced forecasting and dispatch algorithms, enhancing predictability and responsiveness.

The progression from S1 to S3 illustrates a transformation in grid architecture and operation. While total system costs increase from $50B to $65B annually, this rise is justified by; Dramatic emissions reductions, aligning with 2035 clean electricity goals. Enhanced reliability, outperforming traditional systems in resilience under stress conditions. Decreased exposure to fossil fuel volatility, contributing to long-term price stability.

Importantly, the investment profile transitions from high-variable-cost thermal generation to high-fixed-cost, low-marginal-cost renewables, fundamentally altering cost recovery mechanisms and market design needs. Social and environmental co-benefits, though external to pure financial models, further strengthen the case for the S3 pathway.

Deep decarbonization is achievable without sacrificing reliability, provided that adequate investments are made in clean generation, grid flexibility, and digital infrastructure (Arabzadeh *et al*., 2020; O'Shaughnessy *et al*., 2022). The emissions, cost, and reliability summary underscores the importance of integrated planning to achieve a secure, affordable, and sustainable electric grid.

8.2 Cost-Benefit Trade-Off

The transition to a deeply decarbonized electric grid involves a complex interplay between capital investment, system efficiency, reliability, and environmental performance. Key to unlocking the full potential of variable renewable energy (VRE) resources is the strategic optimization of transmission infrastructure and generation siting. This presents a cost-benefit analysis across decarbonization scenarios, focusing on the net present value (NPV) of system-wide investment decisions, the trade-offs between upfront capital expenditures and operational benefits, and the relative merits of mid-range versus aggressive decarbonization pathways, particularly S2 (Moderate) and S3 (Aggressive Net-Zero) (Witcover and Williams, 2020; Bhatia, 2023).

Net Present Value (NPV) is a crucial metric for evaluating the economic viability of infrastructure investment, representing the difference between the present value of benefits (e.g., avoided curtailment, reduced emissions, improved reliability) and the costs of capital deployment over the system's planning horizon, typically 20–30 years.

In all modeled scenarios, optimized siting of generation—particularly wind and solar—based on resource quality and proximity to load or transmission access points resulted in significant improvements in cost-effectiveness. However, without corresponding transmission expansion, these gains are constrained by local curtailment and congestion.

In Scenario S2, where VRE penetration reaches approximately 50%, modest but targeted investments in interregional high-voltage direct current (HVDC) links and reinforcement of intra-regional bottlenecks yield an NPV gain of over $80 billion. These benefits are realized through reduced curtailment (by 40% compared to S1), enhanced capacity sharing, and avoided peaking unit operations. S2 (50% VRE) offers the lowest total system cost with >50% emissions savings. S3 requires significant transmission + storage capex but enables near-total decarbonization.

In Scenario S3, which targets near-total decarbonization (~80% emissions reduction), transmission investment needs are significantly higher. Total capital requirements for new lines and upgrades are estimated at $300 billion (undiscounted), driven by the need to integrate remote wind zones (e.g., Great Plains, West Texas) and distribute surplus solar from the Southwest. Despite high upfront cost, the NPV of avoided curtailment, reliability events, and emissions externalities exceeds $200 billion, making the investment economically justified when social cost of carbon and system-wide savings are accounted for. The NPV analysis confirms that transmission and siting optimization offers long-term economic returns, especially when coupled with smart planning frameworks and regional coordination mechanisms.

Curtailment and reliability shortfalls represent hidden operational costs that accumulate significantly over time. In high-VRE systems, curtailment typically arises due to; Inflexible transmission networks, Temporal mismatch between supply and demand, and Inadequate storage or flexible demand resources.

Each curtailment event translates into lost revenue, higher levelized costs of electricity (LCOE), and increased reliance on fossil backup. Similarly, reliability events—such as loss-of-load occurrences—carry both economic penalties and social costs, including unserved energy, customer outages, and emergency response expenditures.

In S1, with minimal upgrades, curtailment rates reach over 7% of total renewable output, while reliability risks—measured via LOLP—remain low under average conditions but spike under extreme weather.

S2 mitigates these issues through selective transmission investment and load flexibility, reducing curtailment to 3.5% and virtually eliminating high LOLP periods during peak seasons. This balance allows the scenario to deliver >50% emissions savings at the lowest total system cost ($55B/year), marking it as the most cost-optimal decarbonization pathway in the mid-term.

S3, while more costly ($65B/year in annual system costs), avoids nearly all curtailment and achieves negligible reliability risk, thanks to extensive investments in long-duration storage, grid-forming inverters, and transcontinental transmission links. The additional cost is a trade-off for the environmental and long-term societal benefits of deep decarbonization and system resilience (Inderwildi *et al*., 2020; Jing *et al*., 2022). Thus, while S3's upfront CapEx is high, it offers strategic insurance against increasing climate volatility, fossil fuel dependency, and long-term emission penalties. The trade-off lies between short-term affordability (S2) and long-term sustainability and robustness (S3).

The comparative performance of S2 and S3 underscores the importance of strategic planning and intertemporal value optimization.

S2 optimally leverages existing infrastructure, minimizes stranded asset risk, and delivers a strong decarbonization outcome (51%) without requiring transformative grid overhauls. This scenario is most attractive from a near-term cost-efficiency standpoint, particularly if policy and market uncertainty constrain large-scale CapEx.

S3, while requiring over $1 trillion in cumulative new investment by 2040, creates a pathway toward climate-aligned targets and is uniquely resilient to high-impact, low-probability events. It is favored in policy regimes that incorporate the social cost of carbon, public health externalities, and resilience premiums into cost-benefit analysis.

Moreover, NPV modeling shows that delaying investments under S2 to wait for technology maturation or declining costs may erode long-term system value due to lock-in effects from interim fossil infrastructure. Conversely, front-loading transmission and storage CapEx in S3 leads to net-positive returns by year 15, with exponential benefits in system flexibility, reliability, and emission avoidance.

The cost-benefit trade-off in grid decarbonization is not binary but exists along a spectrum of integrated choices in siting, transmission, storage, and system operation. The NPV analysis clearly supports the economic viability of early, optimized transmission and siting strategies, particularly in VRE-heavy scenarios (Obeng *et al*., 2020; Refaat *et al*., 2023). S2 represents the lowest-cost path with strong decarbonization gains and minimal reliability risk, while S3, though more capital-intensive, provides the most robust and environmentally aligned outcome. Policymakers and system planners must weigh these trade-offs in light of evolving climate targets, societal values, and technological trends to ensure the U.S. grid is not only low-carbon but also reliable and economically sustainable.

9. Policy Implications and Recommendations

The findings from this offer critical insights for U.S. policymakers aiming to balance rapid decarbonization with grid reliability, economic efficiency, and resilience. Achieving over 80% variable renewable energy (VRE) penetration is technically feasible and economically viable, but it hinges on forward-looking policy frameworks that enable coordinated infrastructure development, support market evolution, and incentivize resilience-enhancing technologies. This outlines three major policy domains—grid optimization, market reform, and resilience investment—and provides evidence-based recommendations to support a reliable, low-carbon electricity future.

One of the clearest policy imperatives is the need for coordinated siting of generation and transmission resources. This demonstrates that optimized spatial deployment of wind and solar, coupled with a national or regional high-voltage direct current (HVDC) overlay, enables the grid to support over 80% VRE penetration with minimal curtailment and reliability risk. However, current siting and permitting practices are fragmented across jurisdictions, often leading to misaligned resource development and suboptimal transmission buildout.

To overcome this, policymakers should; Establish federal-state coordination frameworks for transmission planning that integrate renewable resource zones, load centers, and environmental impact considerations. Mandate national HVDC corridor designations, similar to the National Highway System, to streamline regulatory approvals and reduce interconnection backlogs. Create financial mechanisms such as green infrastructure bonds or public-private partnerships to accelerate HVDC investments, particularly in high-value corridors like MISO–ERCOT and CAISO–Western Interconnect. Grid optimization is not only about building new lines but ensuring that the location of renewable assets aligns with system value, maximizing both efficiency and reliability at a lower total system cost.

The integration of large-scale VRE will fundamentally reshape wholesale electricity markets. Traditional energy-only market structures—designed around synchronous generators—are inadequate to capture the value of storage, demand flexibility, and inverter-based grid services. This emphasizes that full participation of storage and inverter-based resources must be mandated to unlock their system-level benefits. Key policy recommendations include; Update market rules within ISOs and RTOs to allow storage and hybrid systems (e.g., solar+storage) to provide energy, capacity, and ancillary services without discrimination. Define performance-based compensation mechanisms for fast frequency response, synthetic inertia, and voltage support from inverter-based resources. Develop standardized interconnection and interoperability requirements to ensure that distributed and utility-scale inverter-based technologies can seamlessly coordinate with grid operations. Without such reforms, markets will undervalue the contribution of advanced resources, limiting their deployment and diminishing the ability of the system to respond to VRE variability and ramping challenges.

As climate-induced extreme weather events become more frequent and severe, grid resilience must be embedded into decarbonization strategies. This finds that widespread deployment of grid-forming inverters (80% in S3) and distributed storage systems significantly improves reliability, maintaining voltage and frequency stability in over 99.98% of dispatch hours, even under high-VRE conditions. Policy levers to promote resilience investment include; Federal tax credits or investment grants for grid-forming inverter technologies, especially when integrated into solar, wind, and battery systems. Performance-based incentives for distributed energy resources (DERs) that demonstrate resilience capabilities during grid contingencies. Local resilience standards, coordinated with national goals, that prioritize inverter-based microgrids, community storage, and islandable systems for critical infrastructure. By embedding resilience criteria into technology and investment planning, policymakers can ensure that decarbonization does not compromise reliability—even during high-impact, low-frequency events.

A deeply decarbonized, reliable electric grid is within reach, but only if policy frameworks evolve to reflect the operational realities of a high-VRE system. Coordinated siting and transmission policy can eliminate major bottlenecks. Market reform will enable storage and inverter resources to realize their full value. Finally, resilience investment must become a strategic priority to protect against emerging risks. These recommendations form the backbone of a policy roadmap toward a secure, clean, and future-ready U.S. electric grid.

10. Conclusion

This presents a comprehensive evaluation of decarbonization pathways for the U.S. electric grid, focusing on multi-ISO coordination, transmission optimization, and the integration of high levels of variable renewable energy (VRE). Key findings show that it is both technically and economically feasible to achieve over 80% renewable energy penetration by 2030 without compromising grid reliability or causing excessive cost burdens. Across modeled scenarios, system-wide emissions are reduced by up to 78%, while maintaining reserve margins above 21% and minimizing loss-of-load probability (LOLP) to near-zero levels. These outcomes are made possible through a combination of targeted transmission investments, siting optimization, grid-forming inverter deployment, and market mechanisms that reward flexibility and resilience.

A central conclusion is that integrated, data-driven planning across ISOs is essential to realize deep decarbonization. The current fragmented structure of grid governance—split across MISO, CAISO, ERCOT, and others—leads to inefficiencies in transmission development, resource siting, and reliability management. By contrast, an interregional framework enables better alignment between resource potential and load demand, mitigates curtailment, and reduces total system costs. The importance of a shared planning paradigm is amplified under stress scenarios, such as extreme weather and rapid load spikes, where coordinated reserve sharing and grid-wide situational awareness are crucial.

To meet 2030 climate targets, this recommends three actionable pathways; Accelerate permitting and construction of HVDC transmission corridors linking high-resource and high-load zones. Mandate inverter-based resource standards and update market rules to fully integrate storage, demand flexibility, and fast frequency response. Institutionalize inter-ISO planning through federal-regional task forces with shared modeling tools, data access, and scenario alignment. The Integrated Grid Optimization (IGO) framework developed in this research demonstrates how multi-region coordination, flexible grid technologies, and modernized markets can drive a low-carbon transition at scale. It offers a replicable model for other RTOs, aligning decarbonization goals with economic efficiency and operational reliability. As the U.S. grid evolves under climate, technological, and policy pressures, this framework provides a credible roadmap for delivering clean, reliable, and affordable electricity by 2030 and beyond.

11. Acknowledgements

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12. Data Availability

Simulation scripts and outputs are available upon request and will be published on Zenodo post peer-review.

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