Pathways to Regional Electricity Integration for Atlantic Canada

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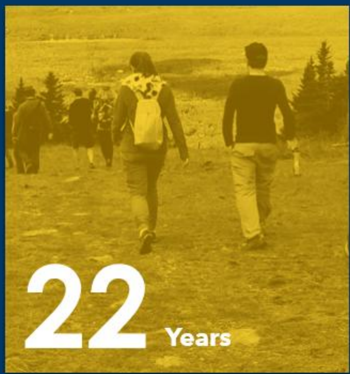
About Dunsky



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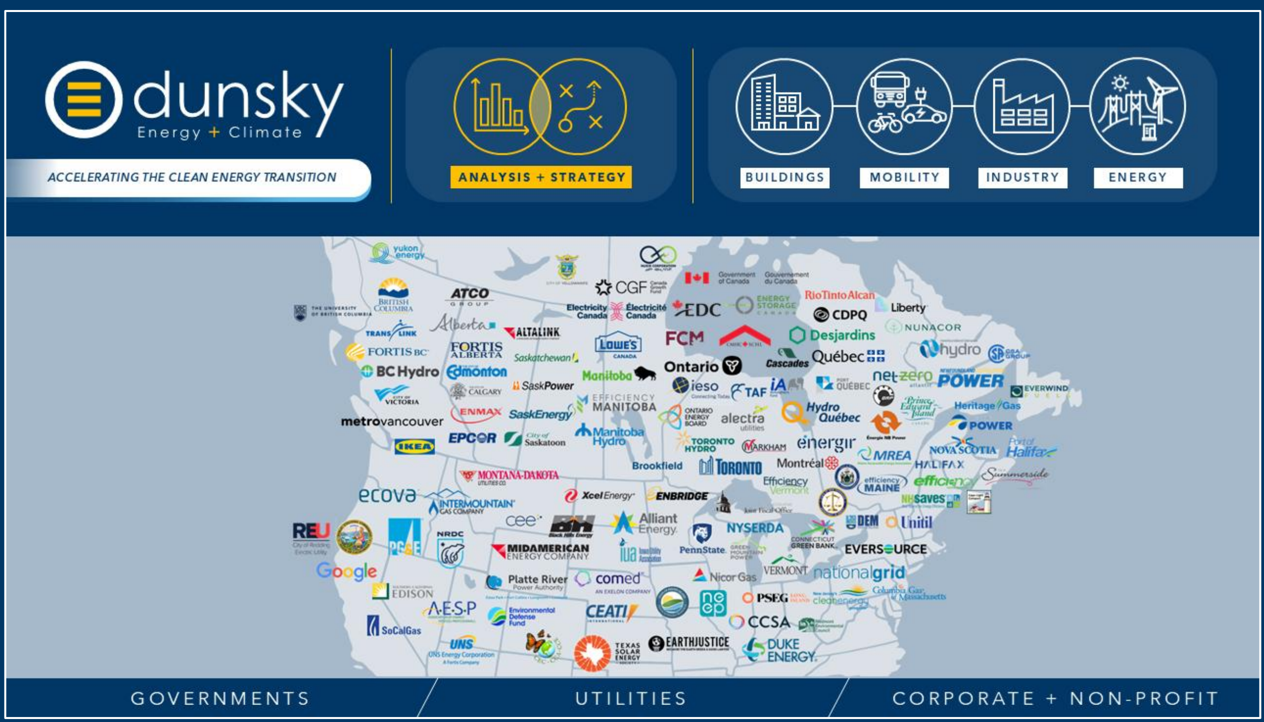

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Executive Summary

Electricity systems in Atlantic Canada are entering a period of rapid change. Provinces across the region are managing growing electricity demand driven by electrification, economic development and population growth. Utilities, system planners, and provincial policymakers face mounting concerns around reliability, affordability, and the scale of investments required over the coming decades. There is growing interest from regional governments and other stakeholders in addressing these challenges through greater coordination and integration of regional electricity systems.[1]

Regional integration can bring significant benefits, including lower costs, improved reliability and resilience, and faster renewable energy development. It also faces real challenges, most notably differing provincial priorities and energy security or economic development objectives. Deeper integration may also require new institutional arrangements, additional human and technical capacity, and clear decision-making processes.

This paper assesses potential opportunities, challenges, and pathways for further regional electricity system integration in Atlantic Canada, based on a review of U.S. regional transmission organizations, the broader integration literature, and discussions with electricity system experts.

> In this report, **regional integration** refers to increased coordination of electricity planning, operations, procurement, transmission development, and/or market activities across the geographic region of Atlantic Canada, meaning New Brunswick, Nova Scotia, Prince Edward Island, and Newfoundland and Labrador. This use of "regional" is distinct from formal electricity reliability or planning regions, such as the Northeast Power Coordinating Council (NPCC), which may cover different geographic boundaries

FORMS OF REGIONAL INTEGRATION

Atlantic Canada is already interconnected, but there are opportunities for more electricity system integration.

Current intertie capacity within Atlantic Canada is less than 1 GW[2], while external interconnection capacity to neighbouring regions is significantly larger. The planned Wasoqonatl reliability tie between Nova Scotia and New Brunswick, expected to enter service in 2028, will partially address this, but internal east-west transfer capacity remains limited.

Despite increasing physical integration, planning and operations remain largely focused within provincial boundaries. Several trends are increasing the value of regional coordination: growing electricity demand and winter peaks, driven by heating electrification; rising ratepayer costs and affordability pressures; and the transition towards renewable and

[1] Crux Energy Consulting and Atlantic Energy Collective. 2026. *An Atlantic Canadian Energy Future*; Government of New Brunswick. 2026. *Fit for the Future – A Comprehensive Review of NB Power*; Atlantic Electricity Cooperation Initiative. Accessed June 12, 2026.
[2] Includes roughly 350 MW between NS and NB, 300 MW between NB and PEI, and 500 MW between NS and NL.

low-carbon generation. Emerging resources such as offshore wind and battery storage could also reshape regional electricity flows and system needs.

While regional integration is commonly assumed to mean a regional wholesale market or a centralized system operator, our research shows that regional integration is often approached incrementally across three broad functional areas:

1. **Planning** (coordinating system planning and infrastructure build-out).
2. **Procurement and markets** (coordinating investment, procurement, and electricity trading).
3. **Operations** (coordinating system operations to improve reliability and efficiency).

Experience from other jurisdictions – including ISO-New England, CAISO's Western Energy Imbalance Market, and the Southwest Power Pool – shows that regions often begin with bilateral trading, reserve sharing, or coordinated planning before moving toward more formal structures. Atlantic Canada is not starting from scratch, with prior experience of regional transmission planning, reserve sharing, and joint dispatch. However, many of these efforts have been ad hoc, bilateral, or time-limited.

THE PATH FORWARD FOR ATLANTIC CANADA

For Atlantic Canada, the right approach is provincially led, grounded in clear mutual benefits, and should begin with practical near-term opportunities that provide genuine system value.

An immediate priority includes aligning on provincial energy plans and policies – and the role of electricity integration within those. Beyond that, it will be important to develop equitable and transparent approaches to allocating costs and benefits, and ensure near-term institutional and infrastructure decisions preserve optionality for future deeper integration.

Near-term priorities fall across all three functional areas (Figure ES1):

1. **Planning:** Coordinated resource adequacy and transmission planning – including shared load forecasts, regional reliability assessments, and joint modelling of capacity needs – could help identify whether provinces can avoid duplicative investments and make better use of regional resources. Joint regional studies provide a practical starting point without requiring a permanent new institution.
2. **Procurement and markets:** Aligning procurement timelines, sharing information on planned resource additions, and developing capacity coordination agreements could improve competition, reduce duplication, and create greater investment certainty for developers and utilities alike.
3. **Operations:** Expanded reserve sharing and coordinated maintenance planning build on existing arrangements between Nova Scotia and New Brunswick, and NB Power's role in serving PEI and Northern Maine. The Wasoqonatl tie creates a timely opportunity to revisit and expand these arrangements.

Figure ES1. Options for regional electricity integration in Atlantic Canada

Less → More

	Planning	Procurement & Markets	Operations
Tier 1 – Near Term	• Coordinated resource adequacy planning • Coordinated transmission planning	• Align procurement timelines & processes • Capacity coordination agreements	• Expand reserve sharing • Coordinated maintenance planning
Tier 2 – Explore Further	• Regional Integrated Resource Planning	• Joint capacity procurement	• Joint economic dispatch
Tier 3 – Monitor	• Regional planning authority	• Regional wholesale electricity market	• Central regional system operator

Options warranting further exploration include regional integrated resource planning, joint capacity procurement, and joint economic dispatch. These could provide meaningful benefits but require more detailed analysis of governance, cost allocation, and implementation requirements. Longer-term options such as a regional planning authority, wholesale electricity market, or centralized system operator may provide value in the future but currently face greater political, institutional, and market barriers (although there is increasing momentum towards a regional ISO).

MOVING FROM CONCEPT TO ACTION

Greater regional electricity integration can provide tangible benefits to Atlantic Canada, particularly in relation to cost containment, reliability and resilience, and renewable energy integration.

The immediate priority is not to decide whether Atlantic Canada should create a full regional electricity market or RTO. Rather, it is to identify functions where coordination can create near-term value, build trust among jurisdictions, and avoid decisions that foreclose future options. Coordinated planning, expanded reserve sharing, aligned procurement, and stronger transmission coordination provide a practical foundation for that next stage of regional collaboration.

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1. Introduction and Context

Electricity systems in Atlantic Canada are entering a period of rapid change. Provinces across the region are managing growing electricity demand largely driven by electrification, while adding new generation sources and pursuing decarbonization targets. At the same time, utilities, system planners and provincial policymakers face increasing concerns around reliability, system costs, and the scale of new infrastructure investment required over the coming decades.

Historically, electricity systems in the region have been planned and operated at the provincial level. While provinces are interconnected and already trade electricity, coordination remains relatively limited compared with many larger regional electricity systems. As system needs evolve, policymakers, utilities, and other stakeholders are increasingly examining whether greater regional electricity integration (between provinces and/or balancing authorities) could improve system efficiency, lower costs, support renewable energy development, and enhance reliability.

Given the close economic, geographic, and energy system ties between Atlantic provinces, deeper collaboration could also support prosperity for Atlantic Canada more broadly by enabling more efficient infrastructure development and better utilization of diverse energy resources.

This paper assesses the potential opportunities, challenges and pathways to further regional electricity system integration in Atlantic Canada, based on a review of U.S. case studies, the broader regional integration literature, and discussions with electricity system experts.

The following section provides a brief overview of Atlantic Canada's electricity systems, outlines key challenges shaping the electricity sector of the four provinces, and reviews past coordination efforts and emerging opportunities for regionalization.

Glossary of key terms

Atlantic Canada: The four provinces that make up the Atlantic Canada region: New Brunswick, Nova Scotia, Prince Edward Island, and Newfoundland & Labrador.

Balancing authority: The entity responsible for maintaining real-time balance between electricity supply and demand within a defined area, including managing frequency and interchange with neighbouring systems. In the U.S., RTO/ISOs often serve as the balancing authority across their footprint. Where no RTO/ISO exists, the balancing authority is often a utility or system operator. In Atlantic Canada, provincial utilities generally perform this function, with NB Power serving as balancing authority for Prince Edward Island, and for Nova Scotia in the New England Power Pool (NEPOOL).

Independent System Operator (ISO): An independent entity responsible for operating the transmission system and, in many cases, administering wholesale electricity markets. ISOs and RTOs perform similar functions, though RTOs generally meet additional criteria related to regional scope and authority.

Joint dispatch: Coordinated operation of generation resources across multiple systems to meet demand using the lowest-cost available resources, subject to reliability and transmission constraints.

Maritimes: A regional area that includes New Brunswick, Nova Scotia, and PEI (and not Newfoundland and Labrador). In electricity reliability contexts, the Maritimes area is recognized within the Northeast Power Coordinating Council (NPCC) and does not include Newfoundland and Labrador.

Planning region: A geographic or operational area used for electricity system planning. A planning region may be defined around a provincial utility or system operator, such as Nova Scotia Power or NB Power, or around a broader regional planning entity responsible for coordinating reliability, transmission, or resource adequacy across multiple jurisdictions (such as NPCC).

Regional Integration: In this report, regional integration refers to increased coordination of electricity planning, operations, procurement, transmission development, and/or market activities across the geographic region of Atlantic Canada, meaning New Brunswick, Nova Scotia, Prince Edward Island, and Newfoundland and Labrador. This use of "regional" refers to the Atlantic Canadian region and is distinct from formal electricity reliability or planning regions, which may cover different geographic boundaries.

Regional Transmission Organization (RTO): An independent organization that operates the transmission system over a multi-utility or multi-state/provincial footprint. RTOs typically coordinate real-time grid operations, administer open-access transmission tariffs, conduct regional transmission planning, and operate wholesale electricity markets. RTOs may also serve as the balancing authority for all or part of their footprint.

Resource adequacy: The ability of an electricity system to maintain enough supply-side and demand-side resources to meet forecasted demand under expected and stressed system conditions.

Reserve sharing: An agreement between utilities or balancing authorities to share operating reserves, reducing the amount each system must carry independently.

2. Atlantic Electricity System Overview

Electricity systems in Atlantic Canada share several structural characteristics. Demand peaks in winter, reflecting widespread electric heating. Utilities are generally vertically integrated and regulated at the provincial level, with each province responsible for planning and operating its electricity system.[3] Across the four provinces, installed generation capacity is about 15,800 MW serving a population of 2.7 million (Table 1).

Table 1. Key system characteristics

Province	Utility / System Operator	Population	Installed Capacity (2023)	Generation Mix Highlights
Nova Scotia	Nova Scotia Power Inc.	1.09 million	2,963 MW[4]	Fossil-heavy mix (coal, gas) with growing shares of wind (13%) and hydro (13%)
New Brunswick	NB Power	870,000	4,585 MW	Diversified mix including nuclear, hydro, gas, coal and wind
Prince Edward Island	Maritime Electric / PEI Energy Corp	180,000	385 MW	Wind-dominated (99%); relies heavily on imports from NB (~70% of demand)
Newfoundland and Labrador	NL Hydro / Newfoundland Power	550,000	8,034 MW	Hydro-dominated (97%)
Total		**2.7 million**	**15,817 MW**	

Transmission links connect the provinces but remain relatively limited, albeit with some recent expansions, including the Maritime Link in 2018 and Wasoqonatl Reliability Tie under construction (Figure 1). Electricity trade between the four provinces is modest. In 2024, Nova Scotia and Prince Edward Island were net importers of electricity, while New Brunswick served as a hub; importing electricity—primarily from Quebec—and exporting to its neighbouring provinces and Maine.

External connections are significant. New Brunswick maintains approximately 775 MW of export capacity to Quebec and roughly 1,000 MW to New England, while Newfoundland and

[3] Nova Scotia recently created an Independent Electricity System Operator (IESO) in 2024 to oversee system planning, grid operations, and procurement of new generation, taking on many of the roles previously managed by Nova Scotia Power.
[4] Includes 150 MW of contracted capacity and energy with NL through the Maritime Link

Labrador has 5,150 MW of export capacity to Quebec , mostly tied to the Churchill Falls Generating Station.

Figure 1. Electricity intertie capacity in Atlantic Canada[5]

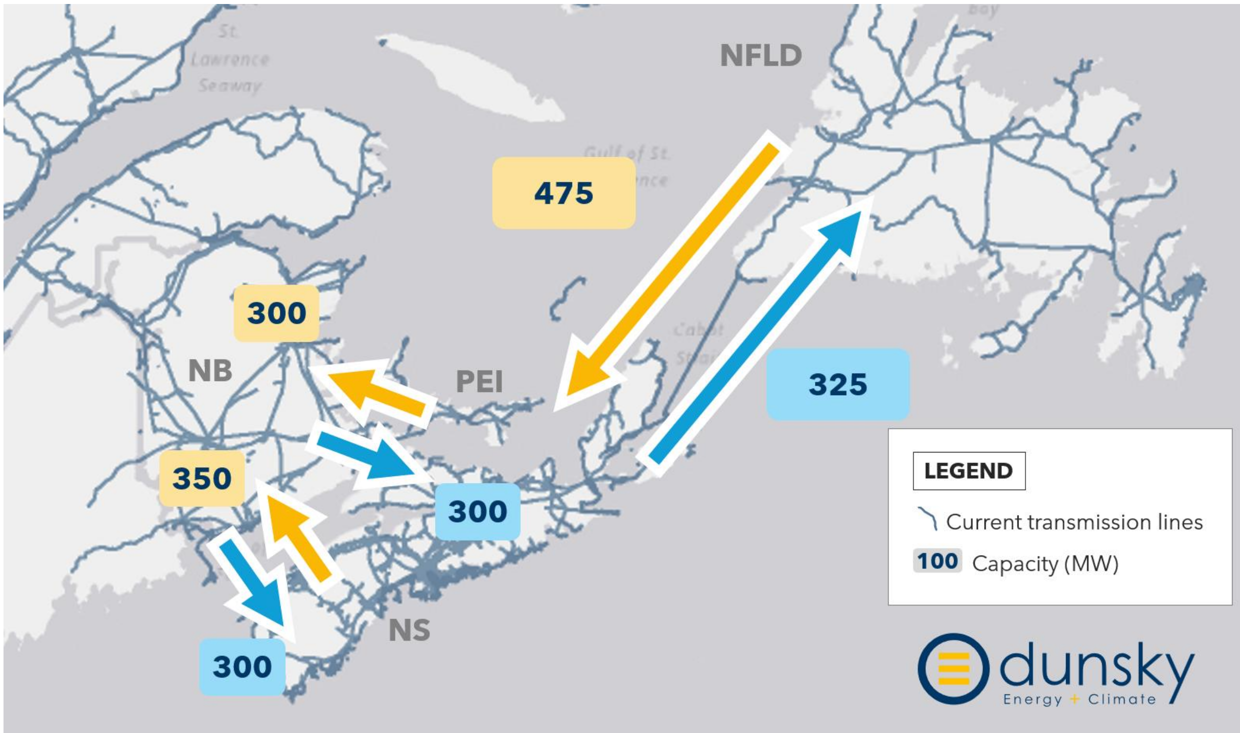

Table 2. Interties and electricity flows within Atlantic Canada

Interconnection	Capacity	Annual Flows
NS-NL (Maritime Link)	325-475 MW	~1,500 GWh (NS net imports)
NB-NS	300-350 MW (expanding to ~650 MW by 2028)	~620 GWh (NS net imports)
NB-PEI	300 MW	~1,200 GWh (PEI net imports)

Capacity numbers from Electricity-Canada_Intertie-Study_Jan21.pdf; Electricity flow data for 2024; NB Power. System Information Archive; NS Power. Hourly Net Energy Flows NS – NB Interconnection; Public Utilities Board Newfoundland & Labrador. Energy Supply Monthly Reports – December 2024.

[5] Intertie Study | Electricity Canada

2.1 System Trends and Challenges

Several structural trends are reshaping electricity systems across Atlantic Canada.

Demand growth and electrification

Electricity demand across the Maritimes (which includes New Brunswick, Nova Scotia and PEI but not Newfoundland and Labrador) is projected to increase by approximately 9% between 2026 and 2035, according to NERC.[6] Winter peak demand is expected to grow faster than summer peaks, driven largely by electrification of heating and population growth in urban areas.

Energy transition and renewable integration

Provinces are pursuing significant expansion of renewable generation as part of decarbonization strategies.

Nova Scotia's Clean Power Plan targets 80% renewable electricity by 2030, largely through new wind generation and energy storage. The province has a legislated target to phase out coal-fired generation by 2030. Wind capacity in the province has grown rapidly and accounted for roughly 30% of electricity generation in 2023, up from 15% in 2010.[7] Grid-scale battery storage is also emerging, with approximately 100 MW already online, another 50 MW expected in summer 2026, and additional procurements planned for late-2026.[8]

Offshore wind development is also being explored. Nova Scotia's Offshore Wind Roadmap aims to enable up to 5 GW of offshore wind leases by 2030, with longer-term potential for significantly larger development.[9] Offshore wind presents untapped renewable energy potential that could bring new economic development opportunities to the Atlantic Canada, but would require significant investments and heightened interregional coordination to unlock.[10]

New Brunswick has also expanded renewable generation, particularly wind, while phasing out petroleum-fired generation. At the same time, the province benefits from a more diversified generation mix that includes nuclear and hydroelectric power, providing stable baseload generation and operational flexibility.[11] The province is also planning to phase out coal generation, although without a legislative requirement.

Although Atlantic provinces have among the strongest renewables growth potential in Canada, this creates emerging risks around balancing variable supply. Expanded interregional interconnections could offer a solution, through greater geographic and resource diversity.[12] A process of regional coordination, whereby the four provinces begin to plan their shared grid collaboratively, would demonstrate promise.

[6] NERC
[7] CER
[8] CBC
[9] Nova Scotia Department of Energy. Offshore Wind Roadmap. Accessed May 26, 2026
[10] CBC
[11] CER
[12] Deloitte

Reliability and resource adequacy

Despite planned additions of new generation capacity, reliability assessments indicate emerging system risks. NERC currently classifies the Maritimes region as facing an "elevated risk" of supply shortfalls during the 2026–2030 period. Under extreme weather conditions or periods of low renewable output, electricity supply may be constrained.[13]

In response, the three Maritime provinces are planning new natural gas facilities over the next 2-5 years to support reliability. These include NB Power's 500-MW Tantramar gas plant, expected to enter service in 2028, and proposed gas or diesel generation in Nova Scotia (300 MW) and PEI (100-150 MW).

Rising system costs

Atlantic Canadian utilities face significant capital investment requirements, including new generation capacity, transmission upgrades, and grid modernization. These investments are expected to place upward pressure on electricity rates. Affordability concerns have become a central issue in utility planning processes and provincial energy policy discussions.

At the same time, electricity system planning remains provincial and siloed, with each jurisdiction developing its own resource plans and energy strategies. This can increase the risk of duplicative investments or inefficient system development, particularly as renewable penetration increases and system needs evolve.

Table 3. Examples of existing Atlantic Canada electricity system coordination

Area	Initiative
Reliability	Reserve-sharing agreement (170 MW) between NS and NB
Resource adequacy	Capacity sharing agreement between NB Power and NS IESO (100 MW)
Transmission	Development of new interties such as the **Wasoqonatl Reliability Tie** (NB-NS) and **Maritime Link** (NS-NL)
Planning	Joint reliability assessments through NPCC (NBP and NSPI)

2.2 Past Coordination and Emerging Priorities

Although electricity systems in Atlantic Canada are primarily organized along provincial lines, the four provinces have a history of cooperation in areas such as reliability planning, transmission development, and resource adequacy.

Utilities in the Maritimes participate in regional reliability frameworks under NERC and the Northeast Power Coordinating Council (NPCC). As part of this process, the region's balancing authorities—NB Power and Nova Scotia Power—jointly conduct probabilistic assessments of

[13] NERC

transmission reliability and resource adequacy covering three- to five-year planning horizons.[14] More targeted, bilateral coordination initiatives have also emerged (Table 3).

Interregional transmission projects have played an important role in expanding system connectivity. The Maritime Link, commissioned in 2018, connects Nova Scotia with hydroelectric generation from the Muskrat Falls project in Labrador and currently supplies roughly 20% of Nova Scotia's electricity demand.

The Wasoqonatl Reliability Tie, currently under construction, will significantly increase transmission capacity between New Brunswick and Nova Scotia when it enters service in 2027. The project is intended to improve system reliability and resiliency, while supporting renewable energy expansion.

Other large-scale proposals have also highlighted the potential role of interregional infrastructure. The Atlantic Loop, originally proposed to connect hydroelectric resources in Québec and Labrador with the Atlantic provinces, was ultimately abandoned in 2023 due to escalating costs, concerns about rate impacts, and lack of firm supply. The federal government also supported the Regional Electricity Cooperation and Strategic Infrastructure (RECSI) initiative in Atlantic Canada from 2016-2018, to identify least cost options for transitioning fossil fuel-reliant regions in Canada to renewable energy through electricity cooperation.

At the same time, new opportunities for coordination continue to emerge. In 2026, Nova Scotia and Massachusetts signed a memorandum of understanding to explore cooperation on offshore wind development and associated transmission infrastructure, including potential coordination with other Eastern Canadian provinces and New England states. The Conference of New England Governors and Eastern Canadian Premiers also issued a declaration in November 2025 indicating their desire to enhance "interregional information-sharing, and analysis on energy matters … to support mutually beneficial infrastructure development that supports shared sustainability and economic priorities…".[15]

Together, these developments illustrate the desire to explore deeper interregional cooperation as electricity systems evolve.

Regional and national governments are increasingly focused on interregional electricity cooperation

Recent policy developments suggest growing momentum for deeper electricity coordination in Atlantic Canada and across Canada.

In New Brunswick, the independent comprehensive review of NB Power recommended immediate discussions on the **potential establishment or sharing of responsibilities of a Maritime Independent System Operator**, as well as a focused political effort to explore

[14] NB Power also acts as balancing authority for PEI and Northern Maine
[15] 46th Annual Conference of New England Governors and Eastern Canadian Premiers. November 2025. Resolution 46-2: Concerning Regional Collaboration on Energy.

regional integration and cooperation among Maritime electric utilities.[16] The Government of New Brunswick's action plan accepted most of the review's recommendations and committed to exploring a Maritime ISO (recommendation 11), advancing political-level discussions with other Atlantic provinces (recommendation 12), expanding procurement coordination with neighbouring utilities (recommendation 13), and considering regional cooperation opportunities in future integrated resource planning (recommendation 42).[17]

Regional discussions are also emerging among the Maritime provinces. Premiers and officials in **New Brunswick, Nova Scotia, and Prince Edward** Island have reportedly discussed opportunities for greater regional coordination, including the potential role of a regional system operator.[18] This builds on recent work by the Atlantic Energy Collective to advance regional integrated resource planning and energy governance.[19]

At the national level, the federal government's Powering Canada Strong strategy **identifies regional integration as a strategic priority for building out Canada's electricity system**. Proposed actions include advancing interprovincial interties and regional planning, improving data sharing and regional grid modelling, and exploring approaches to cost allocation for major regional transmission investments.[20]

These developments are complemented by broader interprovincial efforts, including Ontario's **National Energy Corridor Agreement** with participating provinces and territories to advance new transmission projects and strategic interties across Canada.[21] Together, these initiatives suggest that regional electricity cooperation is moving from a technical planning concept to an increasingly active policy priority.

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[16] Government of New Brunswick. March 2026. Fit for the Future: A Comprehensive Review of NB Power

[17] Government of New Brunswick. May 2026. NB Power Comprehensive Review: Action Plan

[18] McInnis. CBC News. P.E.I. government puts out expression of interest for a battery energy storage system. March 2026

[19] Atlantic Energy Collective. January 2026. An Atlantic Canadian Energy Future

[20] Government of Canada. May 2026. Powering Canada Strong: A National Strategy for an Electrified Canadian Economy

[21] Government of Ontario. March 2026. Ontario Secures Groundbreaking National Energy Corridor Agreement

3. Value of Regional Electricity Integration

Atlantic Canada is facing multifaceted electricity system challenges. According to NERC's 2025 Long Term Reliability Assessment[22] the Maritimes are at an elevated risk for potential reliability issues. The region, particularly Nova Scotia and New Brunswick, is under increased pressure to phase out coal and decarbonize their electricity systems, while undergoing a costly refurbishment of the Mactaquac Generating Station, which provides 672 MW of firm capacity.[23]

In this context, greater interregional electricity system coordination and/or integration is increasingly being considered as one way to address multiple system challenges simultaneously. By enabling provinces to share resources, coordinate investments, and access a broader range of electricity supply options, a process of regional integration can help improve reliability, reduce system costs, and support the expansion of renewable energy.

It should also be acknowledged that Atlantic Canada is not starting from zero: bilateral electricity trading, joint transmission planning, reserve sharing agreements, and open-access transmission markets already exist in the region, particularly between Nova Scotia and New Brunswick.

3.1 Examples of Regional Integration

There is no single model for greater regional electricity system integration. Approaches vary widely across jurisdictions and often evolve gradually over time depending on local regulatory structures, system characteristics, and policy priorities.[24]

Integration can occur at different levels across several aspects of electricity systems:

Planning: How can jurisdictions coordinate system planning and infrastructure build-out?

- Jurisdictions can coordinate long-term planning activities such as transmission development, resource adequacy assessments, or regional load forecasting. Integration can also involve harmonizing technical standards, reliability criteria, or procurement practices across systems.

Operations: How can utilities and system operators coordinate system operations to improve reliability and efficiency?

- Operational coordination can range from information sharing and reserve-sharing agreements to centralized dispatch of generation across multiple jurisdictions. More

[22] Long-Term Reliability Assessment (Source)
[23] Final Clean Electricity Regulations now in effect (Source)
[24] IEA

centralized operations can improve the efficiency of generation dispatch and reduce the amount of backup capacity required to maintain reliability.

Markets and Procurement: How can jurisdictions coordinate infrastructure investment, procurement, and electricity trading?

- Deeper integration can build on existing bilateral electricity trade relationships (e.g., Nova Scotia and New Brunswick have been trading for more than 20 years), potentially expanding over time to include joint dispatch, coordinated trading platforms or regional electricity markets. These arrangements allow the lowest-cost electricity to flow to where it is most needed, improving overall system efficiency. This helps in part define how to pay for system improvements over time.
- Integration may also involve joint ownership of infrastructure such as transmission interties, shared generation projects, or jointly financed system upgrades. These arrangements can distribute investment risks and enable projects that might be difficult for individual jurisdictions to undertake independently.

Figure 2. Characteristics of Power Systems by Level of Integration

Regional Electricity Markets

Electricity markets represent one possible pathway toward deeper regional integration. Market structures vary in complexity, but they generally provide mechanisms for coordinating electricity dispatch and trading across multiple jurisdictions.
At the most integrated end of the spectrum are **regional wholesale markets**, typically operated by independent system operators (ISOs) or regional transmission organizations (RTOs) in the U.S. These markets coordinate generation dispatch across a large geographic area and determine electricity prices through centralized scheduling processes. Participants can trade electricity through both day-ahead and real-time markets.

Wholesale markets use either **nodal or zonal pricing** to clear supply and demand. In nodal markets, prices are calculated at every node across the transmission network using Locational Marginal Pricing (LMP), which captures energy costs, congestion, and losses at each specific location. In zonal markets, the network is divided into a smaller number of geographic zones where all participants face the same price, with within-zone congestion handled through out-of-market redispatch rather than explicit pricing.

Additional market offerings may support system reliability. These include ancillary services (e.g. reserves, voltage support, fast frequency response) or capacity (long-term resource adequacy to meet peak demand forecasts), although these are not present in all markets.

A less complex model is a **real-time imbalance market**, where utilities continue to plan and schedule generation within their own systems but allow a centralized operator to coordinate real-time dispatch across participating systems. This approach can reduce operating costs and improve system flexibility while preserving existing utility structures.

Several regions have adopted imbalance markets as an incremental step toward deeper market integration. Over time, some of these systems—such as the **Western Energy Imbalance Market** (WEIM, administered by the California ISO) and the **Western Energy Imbalance Service** (WEIS, administered by Southwest Power Pool)—have expanded to include day-ahead coordination or additional market services (see Section 3).

3.2 Benefits of electricity integration

Experiences in other jurisdictions suggest that regional integration can produce several types of benefits. These benefits generally fall into three categories.

Cost Savings

- Integration allows electricity systems to operate across a larger geographic footprint, leveraging economies of scale to enable more efficient use of generation resources and transmission infrastructure. Coordinated dispatch can reduce production costs by allowing lower-cost generation to serve demand over a broader footprint. Integration can also reduce the need for duplicative investments by allowing jurisdictions to share reserve capacity and avoid building redundant generation.
- Integration can also create economic opportunities through local renewable energy development, selling surplus power into wider markets to generate utility revenue, and attracting private investment. These can lower costs for ratepayers and support economic development.

Reliability and Resiliency

- Larger, interconnected systems have access to a broader and more diverse set of generation resources. This can improve reliability by providing additional options to meet peak demand or respond to unexpected outages. Interconnections can also strengthen resilience to extreme weather events or fuel supply disruptions by enabling electricity to flow between regions when local resources are constrained. Inter-provincial/interregional trade and integration can also strengthen energy independence and makes systems more resilient to geopolitical shocks.

Renewable Integration and Environmental Benefits

- Regional integration can lead to systems with larger footprints which are generally better able to integrate variable renewable generation such as wind and solar. Differences in weather patterns, resource availability, and demand across a larger geographic area allow system operators to balance variable output more effectively. Integration can also reduce renewable curtailment by enabling excess generation to be exported to neighbouring systems. More integrated systems can also help lower GHG and air emissions, and reduce the land and water footprints required to meet demand.

3.3 Barriers to regional integration

Despite the benefits above, regional integration has developed slowly in Canada. Some of the key barriers limiting progress include:

Provincial authority and policy alignment

- Electricity policy falls primarily under provincial jurisdiction. Each province has its own regulatory framework, utility structure, and energy policy objectives, which can make coordinated planning more complex. Provinces often prioritize domestic energy security and related economic benefits over greater integration with neighbouring jurisdictions.

Cost and benefit allocation

- The benefits of regional infrastructure investments are often unevenly distributed among participants and can be difficult to quantify in advance. Determining how to allocate the costs and share benefits of major investments—particularly for large transmission projects—has been a major barrier to integration, for example during the Atlantic Loop process.

Upfront infrastructure costs

- Regional integration may require new or expanded transmission infrastructure to enable greater power flows between jurisdictions. Developing interties and associated grid upgrades can involve significant capital investment, long permitting timelines, and complex cost allocation discussions among participating jurisdictions.
- Several federal tools to address capital costs exist or are under development:
    - **The Clean Electricity Investment Tax Credit (ITC)** provides a 15% capital cost reduction for qualified interprovincial transmission equipment (both private and Crown utilities are eligible for the tax credit.)[25]
    - **The National Electricity Strategy** proposed new tools to support inter-regional transmission costs, including the creation of a Transmission InterConnect Investment Strategy, and developing a standard cost allocation mechanism based on the European Union's Projects of Common Interest model.[26]

Institutional and coordination costs

- Regional integration can also require new institutional arrangements, such as coordinated planning processes, shared operational protocols, or market platforms. Establishing and maintaining these coordinating mechanisms can involve administrative costs, governance challenges, and the need for regulatory alignment across jurisdictions.

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[25] Government of Canada. Clean Electricity Investment Tax Credit (ITC). Accessed May 26, 2026
[26] Natural Resources Canada. Powering Canada Strong: A National Strategy for an Electrified Canadian Economy. May 2026.

4. Jurisdictional Scan

To inform the identification of potential pathways for greater electricity system integration in Atlantic Canada, Dunsky conducted a review of three regional electricity organizations as case studies of integration in practice. The selected cases illustrate different approaches to regional coordination and reflect a range of institutional structures, governance models, and stages of market development.

Three U.S. Regional Transmission Organizations (RTOs) and associated market initiatives were examined to provide insight into how regional integration has developed under different regulatory, economic, political, and energy system contexts:

- **Independent System Operator – New England (ISO-NE):** Provides insight from a neighbouring region with similar climate and existing transmission connections to Atlantic Canada.
- **California Independent System Operator (CAISO) and Western Energy Markets (WEM):** Illustrates a model in which a regional system operator expanded its footprint beyond its original jurisdiction, and provides market services to vertically integrated utilities outside its core balancing area.
- **Southwest Power Pool (SPP) and Western Energy Imbalance Services (WEIS) market:** Provides a contrasting model in which a regional organization formed through multi-state cooperation and later expanded its operational footprint while also operating a market platform for utilities outside its transmission footprint.

Regional Integration: Context Matters

The case studies below highlight a range of institutional models and integration pathways that offer relevant lessons for Atlantic Canada. The following sections synthesize key findings from our research to compare RTO formation, initial scope and expansion pathways, enabling decisions, and demonstrated benefits for each of the case studies to highlight lessons and takeaways.

It is important to note that these case studies reflect unique contexts and not all elements will be directly transferrable to Atlantic Canada. It is important to note that the scale of these systems is significantly larger than the Atlantic region, both in terms of population and installed capacity. As a result, the examples below should be viewed as illustrative case studies of how regional coordination can evolve over time, with insights into potential pathways that could be adapted to the Atlantic Canada context.

For a detailed summary of each RTO see Appendix A.

4.1 Key Takeaways

4.1.1 Summary of RTO functions

Regional Transmission Organizations (RTOs) perform a common set of functions related to system operations, transmission planning, and electricity market administration. While the specific market designs and governance structures vary across jurisdictions, the core responsibilities of these organizations are broadly similar. Table 4 summarizes key institutional characteristics, scale, and functions of the three case study organizations.

Table 4. Common functions of regional transmission organisations

Category	Function / service	ISO-New England	CAISO & Western Energy Markets	Southwest Power Pool
History	Formation	1997 (2005 as RTO)	1996	1941 (2004 as RTO)
Operations	Annual operating budget (US$)	$269 million	$276 million	$274 million
Scale	Regional footprint	6 New England states	California grid & 11 WEIM states	14 central US states
	Capacity (approx.)	29 GW	129 GW (CA + WEIM)	65 GW
Planning	Regional transmission planning	Yes	Yes	Yes
	Regional load forecasting	Yes	Yes	Yes
	Resource adequacy assessment	Yes (via capacity market)	Yes (state RA requirements)	Yes (regional standards)
Procurement & Markets	Wholesale energy markets (real-time & day-ahead)	Yes	Yes	Yes
	Capacity market	Yes	No (set by state regulators)	No
	Ancillary services market	Yes	Yes	Yes
	Imbalance market	Yes (real-time market)	Yes (WEIM / EDAM)	Yes (WEIS)
Operations	Real-time dispatch	Yes	Yes	Yes
	Transmission tariff	Yes	Yes	Yes
	Reliability coordination	Yes	Yes	Yes

4.1.2 Formation, Initial Scope and Evolution

ISO New England (ISO-NE), the California Independent System Operator (CAISO), and the Southwest Power Pool (SPP) emerged during the restructuring of U.S. electricity markets in the 1990s and early 2000s. Their creation was strongly influenced by federal policy aimed at increasing competition and improving access to transmission networks.

A major driver for the formation of these organizations was the **Energy Policy Act of 1992.** This expanded the authority of the Federal Energy Regulatory Commission (FERC) and enabled merchant generation and greater wholesale electricity trading. This was followed by FERC Orders 888 and 889 (1996), which required open access transmission and encouraged the separation of transmission operations from generation. These orders also promoted the creation of Independent System Operators (ISOs) to ensure non-discriminatory access to the grid. FERC Order 2000 (1999) further encouraged the development of Regional Transmission Organizations (RTOs) and established criteria for their governance and operational scope.

While the regulatory context was similar across regions, the institutional starting points differed. ISO-NE and SPP both evolved from earlier power pools established to coordinate reliability and dispatch among vertically integrated utilities. The Northeast Power Pool (NEPOOL), formed in 1975, transferred system operations to ISO-NE in 1997 while remaining as a stakeholder organization. SPP began as a power pool in 1941, coordinating electricity supply during World War II before gradually expanding its functions and becoming an RTO in 2004.

In contrast, California moved directly from vertically integrated utilities to a restructured market, with CAISO created through state legislation in 1996 to operate the transmission grid and manage wholesale electricity markets.

Despite these different origins, all three organizations initially focused on core functions such as grid operations, transmission planning, and reliability coordination, while market structures evolved over time.

Table 5. Lessons from RTO formation, initial scope and key milestones

Jurisdiction	Formation	Initial Scope	Evolution Milestones
ISO-NE	Formed in 1997 following restructuring of the Northeast Power Pool (NEPOOL, 1975).	Operated regional grid and launched an hourly imbalance energy market and reliability markets in 1999.	• 2003: Introduced LMP, Day-Ahead Market, and Real-Time Market. • Expanded from 40 utilities to 550+ market participants
CAISO	Created in 1996 through California electricity restructuring legislation; began operations in 1998.	Operated the high-voltage grid and an hourly energy-only spot market.	• 2000–01: Market redesign following California electricity crisis. • 2009: Market Redesign and Technology Upgrade (MRTU) introduces LMP, DAM, RTM, ancillary services.

Jurisdiction	Formation	Initial Scope	Evolution Milestones
			• 2013: Expands footprint to include Valley Electric Association in Nevada. • 2014: Launch of the WEIM. • 2026: Launch of Extended Day Ahead Market (EDAM).
SPP	Originated as a power pool in 1941; incorporated as non-profit in 1994; designated an RTO in 2004.	• Coordinated reliability and reserve sharing • Introduced Next-Hour Energy Exchange in 1996 and a regional transmission tariff. • Acts as Regional Security Coordinator under North American Reliability Corporation (NERC).	• 2007: Launch of Energy Imbalance Market • 2014: Integrated Marketplace (LMP, DAM, RTM, operating reserves). • 2021: Launch of Western Energy Imbalance Service (WEIS). • Expanded from 11 utilities in 1941 to 133 market participants as of 2026.

4.1.3 Enabling Decisions

All RTO/ISOs in the US are overseen and regulated by FERC. However, they ultimately operate a system that is influenced heavily by local and state policies. A stark example of this is state renewable energy mandates. These don't directly apply to RTOs but they apply to market participants like generators and distributors. Thus, RTOs must be engaged with stakeholders that affect their operations. How each RTO engages with stakeholders and manages its governance differs by organization.

Table 6. Lessons from RTOs on governance and stakeholder engagement

Jurisdiction	Governance Model	Stakeholder Engagement
ISO-NE	• 10-member board. • All members must have zero financial interest in any market participant. • Must be endorsed by NEPOOL Participants Committee	• Since the formation of ISO-NE, NEPOOL transitioned to a stakeholder engagement group. • Runs Participants Committee and several other committees (markets, reliability, transmission, planning, etc.)
CAISO	• Board of Governors appointed by state governor. • Footprint expansion of CAISO market constrained by state statute.	• CAISO maintains the Market Surveillance Committee, an independent group of 'industry experts' to provide analysis and recommendations on CAISOs

Jurisdiction	Governance Model	Stakeholder Engagement
	• Western Energy Markets is governed jointly by the CAISO Board and WEM Governing body (members nominated by stakeholders), with WEM now given primary authority.	operations, market performance, and rules. • The Annual Policy Initiatives Catalog and Roadmap Process provides opportunities for stakeholders to develop policy proposals.
SPP	• 10-member board independent of market participants, nominated by the Corporate Governance Committee. • 5 committees advise the board on various topics (Oversight, Finance, Human Resources, Strategic Planning, and Corporate Governance). • Adjacent to the board is the Regional State Committee, made up of state commissioners in states that SPP operates in. The RSC shares decision making powers with the Board.	• The RSC allows for robust and integrated decision making amongst state commissioners. • SPP Board retains full administrative control over the WEIS market but operates a Western Markets Working Group as a forum for WEIS participants.

4.1.4 Benefits & Challenges

Although ISO-NE, CAISO, and SPP operate under similar regulatory frameworks, the benefits of regional transmission organizations (RTOs) vary depending on market design, regional resource mixes, and external factors such as fuel prices or state policies. Assessing their impacts can also be challenging because these organizations were created alongside broader electricity market restructuring, making it difficult to isolate the effects of regional coordination alone.

In general, the literature and case studies suggest that regional coordination can deliver benefits through more efficient use of generation resources, improved system reliability, expanded transmission planning, and better integration of renewable energy resources. However, these benefits do not always translate directly into lower retail electricity prices, and RTO regions have also experienced market design challenges and reliability events.

Table 7 summarizes how the benefits of regional coordination have manifested across the three case studies, along with key caveats.

Table 7. Evidence of benefits of regional integration from RTO case studies

Benefit area	Evidence from case studies	Key caveats and challenges
Reliability and resilience	Larger regional systems allow operators to pool diverse generation resources and share reserves, improving the ability to respond to outages or extreme weather events. Centralized system operations and	Reliability challenges still occur in organized markets. For example, natural gas supply constraints have created winter reliability risks in ISO-NE,

Benefit area	Evidence from case studies	Key caveats and challenges
	resource adequacy frameworks also improve visibility into regional system conditions. Several modelling studies suggest that deeper regional integration can reduce reliability risks by allowing systems to draw on a broader resource base during stress events.	and extreme weather events have stressed the SPP system. Market structures alone do not eliminate reliability risks and must be supported by adequate infrastructure and resource planning. There is a lack of quantitative analysis demonstrating reliability benefits post-RTO formation.
Cost savings and operational efficiency	Regional coordination allows lower-cost generation to be dispatched across a wider geographic area, reducing overall production costs. Several studies and market reports estimate production cost savings from coordinated dispatch and trading. For example, SPP reports significant savings ($10.2 billion) since the 2014 launch of its Integrated Marketplace, while the CAISO Western Energy Imbalance Market reports $7.8 billion in cumulative benefits from improved real-time trading.	Quantifying cost impacts is difficult because many studies rely on modelling or internal market analyses without clear counterfactuals. Retail electricity prices depend on many factors beyond market design (fuel prices, infrastructure costs, policy mandates). As a result, efficiency gains do not always translate into lower retail rates.
Renewable energy integration	Regional coordination supports renewable integration by increasing geographic diversity of wind and solar resources and providing access to a broader pool of balancing resources. Regional transmission planning can also facilitate the development of high-quality renewable sites and reduce congestion between resource regions and load centres. For example, transmission expansion in SPP from 2015-2019 enabled significant growth (7400 MW) in wind capacity, and reduced curtailment by 7.1 million MWh.	Renewable integration still requires major investments in transmission, system flexibility, and balancing resources. Differences in state or provincial policies can also create tensions between market operators and participating jurisdictions. In addition, transmission expansion remains challenging due to permitting barriers, cost allocation disputes, and community opposition. [27]

[27] Expanding transmission infrastructure to achieve low-cost, reliable, and abundant energy (Source)

4.2 Lessons from Jurisdictional Scan

The review of three U.S. regional transmission organizations (RTOs)—ISO New England, Southwest Power Pool (SPP), and the California Independent System Operator (CAISO)—highlights several lessons for regions considering deeper electricity system integration.

- **No single model for integration:** There is no standard pathway for regional electricity integration. Each RTO evolved differently depending on regional context, policy objectives, market structure, and system needs. Integration can occur across multiple dimensions—including planning, operations, and market coordination—and often develops gradually over time.
- **Integration often begins with incremental coordination:** Two of the three RTOs originated from earlier forms of voluntary coordination among utilities, in the form of power pools (e.g., NEPOOL and SPP). These arrangements initially focused on reliability and operational coordination. Over time, they evolved into more formal structures with centralized planning, operations, and market mechanisms. Early cooperation can help build trust among utilities and policymakers, enabling deeper integration later as new needs arise, such as balancing increased renewable supply.
- **Institutional and regulatory context matters:** The creation of U.S. RTOs was strongly influenced by federal policy reforms in the 1990s, including open-access transmission requirements issued by the Federal Energy Regulatory Commission (FERC). These policies were designed to address barriers to interstate electricity trade and deregulate vertically integrated electricity markets. In Atlantic Canada, no equivalent federal regulatory driver or barrier exists. Instead, provincial jurisdiction over electricity policy remains a key factor shaping coordination.
- **Governance design is critical:** Governance structures play a central role in building stakeholder confidence. For example, SPP uses an independent governance model that incorporates state participation in decision-making, which has supported expansion across multiple jurisdictions. In other cases, governance arrangements have been a source of tension—for example between ISO New England and state governments pursuing clean energy policies, or between CAISO and other western states considering participation in its market platforms.
- **Benefits can be difficult to measure directly:** RTOs have expanded significantly over time in terms of geographic coverage, membership, and services, suggesting perceived value among participants. However, the economic benefits of integration can be difficult to isolate. While RTO studies often identify system-level cost savings, these have not always translated into lower retail electricity rates for consumers. Retail prices are influenced by many factors—including fuel costs, infrastructure investment, and climate-related reliability spending—making it difficult to attribute rate outcomes directly to market structure.
- **Market size influences potential benefits:** U.S. RTOs operate across large geographic areas with many market participants, enabling competition and liquidity in electricity markets. Atlantic Canada has a much smaller electricity system with fewer participants, which may limit the potential benefits of competition-based market structures.

5. Implications for Atlantic Canada

5.1 Principles for regional integration

Regional integration should be guided by a clear set of shared principles among utilities, system operators, governments and other stakeholders. These principles can help ensure that integration efforts deliver mutual benefits while maintaining flexibility for future evolution. They may include:

1. **Adopt a phased approach**: Integration should occur incrementally, beginning with lower-complexity coordination measures and expanding over time as benefits are demonstrated.
2. **Provincial leadership**: Integration initiatives should be provincially led and aligned with provincial energy policies and utility mandates. Bottom-up cooperation is more likely to succeed than top-down institutional restructuring.
3. **Establish clear mandates and transparent processes**. Roles, responsibilities, decision-making authority, and accountability mechanisms should be clearly defined for all participating entities. Transparent planning assumptions, modelling inputs, decision criteria, and stakeholder and rights-holder engagement processes will be critical to building trust and legitimacy.
4. **Ensure transparent and equitable cost-benefit allocation**. Clear mechanisms should be established to allocate costs and benefits among participating jurisdictions in proportion to the benefits received. Frameworks should be holistic and consider the human, financial, and technical resources required to implement and sustain regional coordination.
5. **Align integration with provincial priorities**. Integration should support core provincial objectives, including electricity affordability, reliability and resilience, and the integration of renewable and low-carbon energy resources.
6. **Maintain optionality**. Near-term decisions should avoid locking out future integration pathways. Institutional and infrastructure decisions—such as governance structures, transmission investments, and system operator mandates—should be designed to accommodate potential future expansion of regional coordination or market mechanisms.

Maintaining optionality is particularly important given several upcoming institutional decisions in Atlantic Canada, including the siting of the Nova Scotia IESO's system operations infrastructure. Ensuring these decisions are made with potential regional coordination in mind can help preserve future integration opportunities.

5.2 Options for Regional Electricity Integration in Atlantic Canada

Building on current initiatives, there are three main functional areas where Atlantic Canada could further integrate electricity systems: **planning, operations, and procurement & markets**. These options vary in complexity, implementation requirements, and potential benefits. To help prioritize potential pathways, we assessed integration options using a three-tier framework based on both potential value and implementation feasibility.

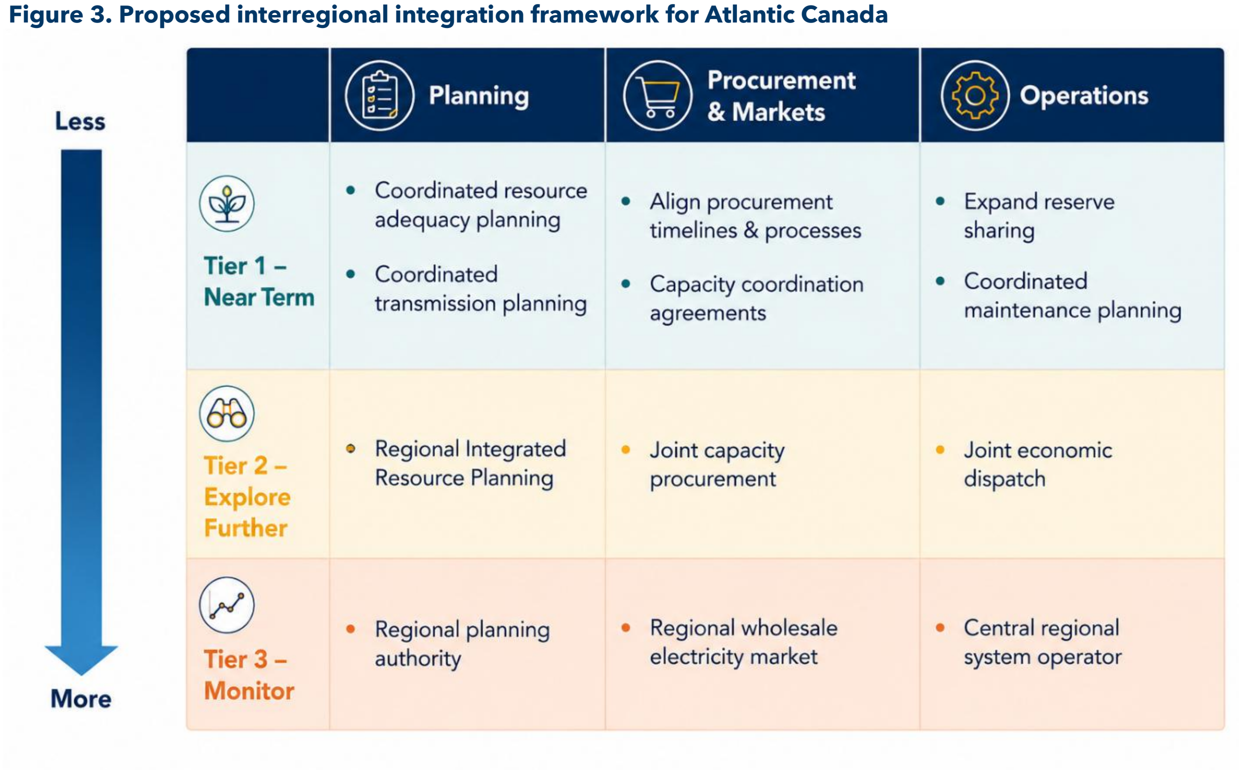
Tier 1 – Near-term opportunities: Options that provide clear mutual benefits, can be implemented using existing institutional structures, and require limited regulatory or legislative change.

Tier 2 – Explore further: Options with potentially significant system benefits but that face implementation barriers, such as institutional complexity, unclear cost allocation, or the need for new governance structures.

Tier 3 – Monitor: Options that may offer value in the longer term but currently face substantial political, institutional, or market barriers, or where the magnitude of benefits remains uncertain.

Figure 3 summarizes potential integration opportunities across these categories; we expand on these in the section below.

Figure 3. Proposed interregional integration framework for Atlantic Canada



5.2.1 Planning

Regional planning coordination represents one of the most practical starting points for deeper integration. Planning processes typically involve fewer institutional changes than operational or market reforms while still enabling significant system-wide efficiencies.

Near-term opportunities

Near-term coordination could focus on expanding existing information sharing and modelling processes across jurisdictions. This could include coordinated transmission planning and resource adequacy assessments, supported by shared load forecasts and regional system modelling.

Such coordination could help identify opportunities to defer or avoid duplicative investments in generation and transmission infrastructure. For example, regional modelling could inform whether planned gas generation capacity in both Nova Scotia and New Brunswick could be partially offset through coordinated planning and reserve sharing.

Transmission planning is primarily conducted independently by each provincial utility.[28] Regional planning could identify opportunities to develop generation or transmission resources across provincial boundaries that reduce overall system costs or improve reliability. A coordinated process could include shared scenarios analysis, regional system modelling, and jointly developed transmission plans. Similar approaches are used in RTOs in the United States and mandated by FERC (see "Interregional Planning Frameworks" below).[29] Implementation would require agreement on governance and cost allocation frameworks to ensure investments are distributed based on the benefits received.[30]

Interregional Planning Frameworks

ISO-New England's Longer-Term Transmission Planning (LTTP) process provides a model of policy-driven transmission planning. Through the New England States Committee on Electricity (NESCOE), New England states can identify long-term needs related to decarbonization, electrification, and renewable energy development, direct ISO-NE to conduct regional studies, and request competitive solicitations for transmission projects. The first LTTP initiative arose from ISO-NE's 2050 Transmission Study and includes upgrades to increase transfer capability between Maine and southern New England while enabling at least 1,200 MW of new onshore wind generation in northern Maine.

Other northeastern U.S. initiatives, such as the Northeast Collaborative on Interregional Transmission, Northeast International Committee on Energy, and Joint ISO Planning Committee, also illustrate how jurisdictions can coordinate transmission planning across RTO and state boundaries. for a similar forum in Atlantic Canada could help Nova Scotia, New Brunswick, Prince Edward Island, Newfoundland and Labrador, and neighbouring

[28] Past one-off regional planning processes include the Regional Electricity Cooperation and Strategic Infrastructure (RECSI) initiative and the Clean Power Roadmap for Atlantic Canada, which led to the Atlantic Loop concept
[29] FERC Order 1920 (Source)
[30] See Canada Electricity Advisory Council's final report for more detail

jurisdictions identify and advance interprovincial transmission projects that improve reliability, facilitate renewable development, and reduce overall system costs.

Joint regional studies have been used in the past to advance inter-regional planning in Canada and the U.S. Examples include the Joint Targeted Interconnection Queue (JTIQ) "Seams Planning" process conducted by MISO and SPP; independent planning bodies like the U.S. Northwest Power and Conservation Council; and the Regional Electricity Cooperation and Strategic Infrastructure (RECSI) study in Atlantic Canada. These demonstrate how regional modelling and scenario analysis can be coordinated across jurisdictions without requiring utilities to relinquish planning authority. These activities could be implemented through existing utility and system operator relationships, potentially with the Nova Scotia IESO playing a coordinating role as it develops its planning functions.

Explore further

A more advanced step would involve regional integrated resource planning, where provinces jointly assess future supply and demand scenarios and evaluate coordinated resource portfolios. This could include joint analysis of renewable resource development, transmission expansion, and firm capacity requirements.

Such an approach could identify least-cost regional solutions while still allowing provinces to retain control over procurement and policy decisions.

Monitor

Over the longer term, deeper planning integration could involve the creation of a regional planning authority responsible for coordinated transmission and resource planning across multiple jurisdictions. While this model exists in several U.S. RTOs, it would require significant governance and regulatory alignment in Atlantic Canada and is therefore better considered a longer-term possibility.

5.2.2 Operations

Operational coordination focuses on improving how existing resources are used across jurisdictions. Compared with planning reforms, operational integration can often deliver immediate system benefits with relatively modest institutional changes.

Near-term opportunities

Near-term operational integration could build on existing coordination mechanisms among Maritime utilities. Reserve sharing agreements already exist between Nova Scotia Power and NB Power and between NB Power and Prince Edward Island. These arrangements could potentially be expanded as new transmission infrastructure—such as the Wasoqonatl reliability tie between Nova Scotia and New Brunswick—comes into service.

Additional coordination could also occur through joint maintenance scheduling and improved information sharing among system operators, helping reduce operational risks and improve system reliability.

Explore further

A more advanced step would involve joint economic dispatch, where system operators coordinate generation scheduling across jurisdictions to ensure the lowest-cost available resources are used to meet regional demand. Unlike full wholesale markets, this approach can be implemented while generation assets remain owned by vertically integrated utilities.

Nova Scotia and New Brunswick previously piloted joint dispatch between 2014 and 2017, but the pilot was never made permanent. Revisiting this concept in light of recent discussions around a Maritime ISO could help reduce generation costs while maintaining existing utility structures, particularly as renewable generation increases and system flexibility becomes more valuable.[31]

Monitor

A deeper form of operational integration would involve the establishment of a centralized regional system operator responsible for real-time system operations across multiple jurisdictions. While this model is common in U.S. RTOs, it would require significant institutional and political alignment among Atlantic provinces and should therefore be viewed as a longer-term possibility.

Federal role in interregional transmission development

The federal government has several tools and levers to support and accelerate the development of interregional electricity infrastructure.

In 2024, the Canada Electricity Advisory Council called for stronger federal support to accelerate the buildout of transmission interties between provinces.[32] Recommended tools included grants, tax credits, and other mechanisms to reduce project risk, as well as transmission capacity reservations similar to the U.S. Department of Energy's Transmission Facilitation Program, where the federal government can act as an "anchor customer" by purchasing a share of long-term transmission capacity.[33]

The Council also recommended developing a standardized and transparent cross-border cost allocation mechanism to support equitable cost-sharing among participating jurisdictions; establishing a clearer process for identifying priority intertie projects and accelerating permitting and approvals; and using the Canada Energy Regulator's authority to help facilitate interregional collaboration.

Many of these themes were reflected in the federal government's May 2026 Powering Canada Strong national electrification strategy, including greater federal-provincial-territorial collaboration, consideration of an expanded role for the Canada Energy Regulator in intertie development, and new approaches to data sharing and interregional grid modelling.[34]

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[31] See for example, Government of New Brunswick. 2026. Fit for the Future: A Comprehensive Review of NB Power, and Atlantic Energy Collective and Crux Energy Consulting. 2026. An Atlantic Canadian Energy Future.
[32] Canada Electricity Advisory Council. May 2024. Final Report: Powering Canada: A blueprint for success
[33] U.S. Department of Energy. Transmission Facilitation Program. Accessed June 5, 2026
[34] Natural Resources Canada. May 2026. Powering Canada Strong: A National Strategy for an Electrified Canadian Economy.

5.2.3 Procurement and Markets

Integration of procurement processes and electricity markets represents a more advanced stage of regional integration but may offer additional long-term opportunities to improve system efficiency and investment decisions.

Near-term opportunities

In the near term, provinces could improve coordination by aligning procurement timelines and sharing information on planned capacity procurements. This could help ensure that new investments are evaluated in a regional context and avoid unnecessary duplication of resources.

Provinces could also explore capacity coordination agreements that allow utilities to procure capacity from neighbouring jurisdictions when cost-effective. For example, Nova Scotia's IESO is negotiating an agreement to procure capacity from NB Power's planned Tantramar generation facility.[35]

Explore further

A more advanced step would involve joint capacity procurement, where provinces coordinate procurement processes to acquire new generation or storage resources that serve multiple jurisdictions. This approach could allow provinces to benefit from larger project scale, improved competition, and better alignment of resource development with regional system needs.

Monitor

Over the longer term, deeper market integration could involve the development of regional electricity markets that coordinate dispatch and trading across multiple jurisdictions. These could range from real-time imbalance markets to more comprehensive wholesale electricity markets. Regions often begin with real-time coordination mechanisms before expanding to broader market structures that include energy, capacity and/or ancillary services.

However, given the relatively small size of Atlantic electricity systems and the dominance of vertically integrated utilities, full market integration may face significant implementation challenges in the near term. Although the US RTO case studies illustrate the potential for regional markets to evolve from vertically integrated utilities, in the case of Atlantic Canada, more limited forms of coordination—such as enhanced bilateral trading or real-time balancing mechanisms—may represent more practical intermediate steps.

[35] IESO Nova Scotia takes next step to secure important additional capacity for provincial power grid (Source)

5.3 Benefits of Regional Integration

Regional electricity integration can provide benefits across three primary dimensions: cost savings, reliability and resilience, and renewable energy integration. Table 9 outlines these benefits in greater detail for each of the types of integration proposed above.

Table 8. Benefits mapping to regional integration options

Integration option	Cost savings	Reliability & resilience	Renewable integration & environment
Coordinated transmission planning	Identifies least-cost regional transmission investments and reduces duplicative infrastructure	Improves intertie capacity and system redundancy	Enables access to geographically diverse renewable resources
Resource adequacy planning	Reduces need for duplicative firm capacity investments	Improves regional reserve margins and contingency coverage	Supports integration of variable renewable energy
Procurement coordination	Enables larger procurement opportunities and potential economies of scale	Diversifies supply options	Facilitates development of renewable resources in optimal locations
Reserve sharing	Reduces required reserve capacity and associated costs	Improves ability to respond to system outages	Supports balancing of renewable generation variability
Joint dispatch	Optimizes use of lowest-cost available generation	Improves system flexibility during peak demand	Reduces renewable curtailment
Electricity markets	Reduces renewable curtailment	Improves price transparency and trading efficiency	Facilitates integration of renewable generation

5.4 Conclusion

Atlantic Canada has reached a moment where greater regional electricity coordination is both increasingly necessary and increasingly possible.

Provinces across the region face similar pressures: rising demand, growing winter peaks, affordability concerns, reliability risks, decarbonization requirements, and major upcoming investments in generation and transmission. At the same time, **regional and national policy discussions are increasingly focused on interregional cooperation**. The question is no longer whether coordination has value, but where it can deliver the greatest near-term benefits and how it can be advanced in a practical, provincially led way.

The evidence reviewed in this report suggests that regional integration can provide tangible benefits for Atlantic Canada, particularly through cost containment, reliability and resilience, and renewable energy integration. However, integration does not need to begin with a full regional electricity market or RTO. The most practical near-term opportunities are functional and incremental: coordinated resource adequacy planning, regional transmission planning, expanded reserve sharing, aligned procurement, and improved operational coordination. These steps can create value for ratepayers and the electricity system while building trust and preserving optionality for deeper integration over time.

These findings suggest that **the most relevant near-term question for Atlantic Canada is not whether to pursue full market integration, but which coordination functions are likely to provide practical value under current institutional and system conditions**. Further work could focus on assessing specific opportunities for coordinated planning, reserve sharing, procurement alignment, and transmission coordination, including their costs, governance requirements, and distribution of benefits across jurisdictions. This would allow regional integration options to be evaluated on a phased and evidence-based basis, while preserving flexibility for deeper collaboration if future conditions support it.

Appendix A: RTO Summary

Context

Dunsky is supporting the Ecology Action Centre (EAC) in efforts to inform the public and key provincial and the electricity sector stakeholders about the **benefits, opportunities, and potential pathways** for greater regional electricity integration in Atlantic Canada.

As part of this work, Dunsky reviewed three U.S.-based Regional Transmission Organizations (RTOs) to better understand the motivations for regional integration, key enabling decisions and design choices, evolutionary and expansion pathways, and benefits and challenges observed in practice:

1. **ISO-New England (ISO-NE)**
2. **Southwest Power Pool (SPP**) and Western Energy Imbalance Service Market (WEIS)
3. **California Independent System Operator (CAISO),** including the Western Energy Imbalance Market (WEIM)

This memo provides a comparative summary of the key findings from the jurisdictional scan, followed by detailed research summaries for each of the three organizations.

Summary of RTOs

Category	ISO-New England	California ISO (CAISO)	Southwest Power Pool (SPP)
Type	RTO	ISO (State-created)	RTO
Regional footprint	Six New England states (excluding NE Maine) 7.6 million retail customers	California wholesale grid & Western Energy Imbalance Market (WEIM) participants across Western U.S. and B.C. Directly serves 32 million customers.[36]	Central U.S. multi-state footprint; expanding western services. 133 members serving over 18 million customers
Market size	28.9 GW capacity[37]	60 GW (CAISO); 129 GW (WEIM)	65.6 GW capacity[38]
Operating costs	US $269M (2025)[39]	US $276M (2025)[40]	US $274M (2024)[41]
Services & functionality	Central dispatch, day-ahead & real-time markets, capacity and ancillary markets, regional transmission planning	Day-ahead & real-time markets (LMP), transmission planning, WEIM real-time balancing market, reliability coordinator services	Day-ahead & real-time Integrated Marketplace, consolidated balancing authority, transmission planning, WEIS imbalance market, reliability coordination
Formation date	1997 (RTO designation 2005)	1996 (ISO formation) 2014 (WEIM)	1941 (power pool with 11 utilities) 2004 (RTO)
Formation driver(s)	Reliability coordination via NEPOOL FERC Orders requiring open access transmission (1996)	State-mandated restructuring following federal Energy Policy Act (1992) and liberalization	WWII coordination among utilities; later FERC-led wholesale competition and open access reforms

36 Our Business - CAISO (Source)
37 Key Stats – ISO-NE (Source)
38 Fast Facts – SPP (Source)
39 ISO New England Regional Update (Source)
40 2025 Draft Final Budget and Grid Management Charge Rates – IESO (Source)
41 SPP's Stakeholder Report: November 2023 (Source)

Category	ISO-New England	California ISO (CAISO)	Southwest Power Pool (SPP)
Evolution & expansion pathway	1971: Northeast Power Pool 1997: ISO formation 1999: Wholesale market 2003: Major market reforms (LMP, DAM, RTM) 2008: Forward capacity market launched	Post CA energy-crisis redesign (2000–01) 2009: market updates incl. LMP & Day Ahead/Real Time markets 2013: CAISO expansion into Nevada 2014: WEIM launch; scaled from 2 entities to large western coverage Governance partially devolved in 2024	1941: Power pool 1960s: regional reliability org 2004: RTO formation 2007: EIS market 2014: Integrated Marketplace Expanding western footprint, strong growth post-2000
Governance model	Independent board; NEPOOL acts as stakeholder advisory group; states participate through advisory bodies	CAISO board appointed by CA Governor; WEIM governed jointly with independent WEM Governing Body (expanded authority in 2024)	Independent board plus strong Regional State Committee (RSC) with shared decision-making authority
Documented benefits	Qualitative reliability benefits and centralized planning Limited quantified net cost savings evidence	WEIM gross benefits: $7.8B since 2014 Mixed evidence on retail cost impacts (cost savings, high rates) Regionalization improves reliability in modeling studies	Transmission investments ~3.5 benefit-cost ratio & $16.6B NPV (Brattle) $10B+ marketplace savings claimed (limited public methodology)

RTO Scan Synthesis

Purpose: Compare RTOs across five dimensions to understand common pathways, design choices, success factors, what didn't work, market size/scale impacts, and implications for Atlantic Canada (starting point, sequencing, services, roles etc.)

Formation

Key questions	ISO-New England	CAISO + WEM	SPP
Initial driver(s) for RTO/ISO formation?	NEPOOL already provided regional coordination and planning. Federal liberalization push (Energy Policy Act of 1992 & FERC Order 888/889), belief that competition would lower costs.	California liberalization push (aligned with Federal energy policy act); AB1890 mandated creation of ISO and power exchange. Goal: introduce competition and lower retail rates.	Formation of power pool to meet industrial demand during WWII. Evolved into ISO/RTO during Federal liberalization/integration push (Energy Policy Act 1992, FERC Orders 888/889, 2000).
Was formation voluntary or mandated (regulator or legislation)?	Voluntary (aligned with federal regulation)	Mandated (state legislation)	Voluntary (aligned with federal regulation)
Who were the proponents? Who resisted?	NEPOOL utilities with state support	California state legislature	Majority of members were proponents, but several important members withdrew in protest to the creation of a regional transmission tariff.

Themes and takeaways:

- Differing formation drivers: Utility-driven to meet load growth (SPP in 1940s) or reliability needs (NEPOOL in 1970s) vs state-mandated to introduce competition and reduce costs (CAISO). Formation pre-dates decarbonization or renewables objectives.
- Federal policy was major catalyst: 1992 Energy Policy Act (liberalization and competition) and FERC open access orders influenced SPP → RTO formation (ISO-NE and SPP) and creation of CAISO (state-driven but aligned with federal goals). This is US-specific and presents a major difference between US and Canada policy.
- Gradual/voluntary vs. sudden/crisis-driven: SPP and ISO-NE evolved gradually over decades, enabling development of institutions and trust; CAISO was mandated into existence, then had to manage energy crisis which forced redesign.

Initial Scope

Key questions	ISO-New England	CAISO + WEM	SPP
Which functions or services were included at launch?	ISO formed 1997, took over operation from NEPOOL. Launched wholesale market (spot/balancing market + reliability market) in 1999.	Operation of high-voltage grid, enforced open access, ran Power Exchange hourly market (all energy was required to be settled through this).	RTO designation 2004, original market design was energy imbalance only.
What was excluded from initial scope?	Nodal/LMP; Forward Capacity Market (2008)	Nodal/LMP (2009)	Integrated Marketplace (real-time wholesale, day ahead, etc.) added in 2014.
Initial footprint and size?	Six NE states (except Northern Maine)	California (large system)	Majority of ND, NE, KS, OK.
What authority did it have over transmission, planning and procurement?	Grid operations, regional Tx planning, FERC-approved tariff.	Grid operations, annual transmission planning, procurement of capacity if shortfall (based on CPUC requirements).	Grid operations, centralized transmission planning, FERC transmission tariff, resource adequacy program.

Themes and takeaways:

- All three launched with core planning + operational functions (grid operation, transmission planning, reliability), with limited markets (wholesale markets for ISO-NE and CAISO; energy imbalance market for SPP).
- Key market design updates were introduced later – LMP / nodal pricing in 2003 (ISO-NE) and 2009 (CAISO), and fully integrated markets in 2014 for SPP.
- Initial footprint varies from single state (CAISO) to multiple states (SPP, ISO-NE) – but market size is large in all cases (30-50 GW, multi-state systems). By comparison, NS and NB ~8 GW; adding NL and PEI ~17 GW.

Pathways & Evolution

Key questions	ISO-New England	CAISO + WEM	SPP
What expanded first – footprint, services, or governance?	Services (Standard Market Design); Stable footprint (6 states) Market expansion from 40 utilities to 550 participants	Services (MRTU Redesign 2009); then geographic expansion via WEIM (2014)	Consistent expansion of both footprint and services.
What was expansion driven by? (eg policy, benefits, markets, etc.)	Market reforms: need for LMP and day-ahead markets.	Response to California electricity crisis (2000-01) and state renewable mandates	Policy and benefits
Was expansion mandated or voluntary?	Service expansion driven by regulation and renewable mandates	WEIM expansion driven by voluntary participant uptake – now includes 22 balancing authorities in 11 states	Expansion driven by member utilities
How did integration happen – incrementally or in major redesigns?	Incrementally – NEPOOL to ISO-NE	Major redesigns – mandate of ISO to MRTU redesign following crisis.	Incrementally – Power Pool to RTO with various market reforms.
What triggered expansion or new services?	Market reforms led to increased price transparency, more efficient operations, and better price hedging.	Response to crisis. SB350 (renewable energy mandate) led to creation of new market products. Demand for more integrated services in the rest of the Western Interconnection.	Demand for more integrated services in the neighbouring jurisdictions and Western Interconnection.

Themes and takeaways:

- ISO-NE: no footprint expansion since formation; greater integration from NEPOOL -> ISO-NE, expansion of services offered (wholesale and day ahead markets, LMP)
- CAISO: market reforms triggered by CA energy crisis; CAISO expanded into Nevada (2013) then launched WEIM (2014) which now offered imbalance services to large western footprint
- SPP: footprint and services both expanded incrementally, from power pool to RTO and market offerings including imbalance market (2007) and integrated market (2014)
- Service expansion usually precedes geographic: ISO NE and CAISO market design changes; SPP gradual for both
- Incremental expansion is the norm unless crisis forces major redesign (CAISO)

- New services often driven by tangible benefits or problems (e.g. RE integration challenges, member demand). Expansion usually voluntary driven by participant demand rather than legislative requirements

Enabling decisions

Key questions	ISO-New England	CAISO + WEM	SPP + WEIS
Governance structure and oversight	Non-profit, 10-member independent Board; committees (markets, reliability, transmission, etc.) advise Participants Committee (formerly NEPOOL). Federal oversight (FERC, NERC/NPCC). States pushing for greater governance role (2020s).	State-appointed board Federal oversight (FERC, NERC) CAISO = balancing authority for WEIM. WEM – independent governing body, shares governance of WEIM + EDAM with CAISO. Ongoing effort (Pathways Initiative) to devolve authority from CAISO to an independent Regional Organization with full authority over markets	10-member Independent board. Members committee (market reps) provide input. Decision-making shared with State commissioners (RSC) Federal oversight (FERC, NERC/MRO/SERC)
How are costs and benefits allocated among participants?	Recovers operating costs via FERC-approved tariff. Tx costs allocated by regional load.	Grid management and Tx access charges ($/MWh); interconnection upgrade costs; capacity procurement charges	Recover operating costs via $/MWh tariff rates based on load contribution. Tx costs – "highway/byway" methodology (region-wide or zonal allocation)
What regulatory or legislative changes were required to enable expansion?	Formation driven by US Energy Policy Act (1992) + FERC open access orders (1996) State policies (RPS, DER incentives) impact ISO-NE operations and grid mix.	2025 CA bill enabled WEM independent governance. CAISO legislative change required to fully devolve governance of WEIS. State legislation (2015) directed CAISO to study expansion.	Energy Policy Act (1992) and FERC open access orders (1996) led to RTO development. Formal RTO approval in 2004 – took 12 years and 3 attempts
How were disputes resolved?	Conflicts between states and ISO-NE on market rules (MOPR) preventing clean energy targets; pressure from FERC and regulators led to proposed reforms and broader governance reform discussions	FERC adjudication, member negotiation (WEM)	FERC adjudication, RSC state input
How are stakeholders engaged?	In-depth stakeholder process (eg NESCOE, NECPUC) - states complain that they have little influence or authority	Formal stakeholder process (CAISO)	SPP operates a robust stakeholder process with

Key questions	ISO-New England	CAISO + WEM	SPP + WEIS
			numerous forums and advisory groups. Western Markets working group for market participants

Themes and takeaways:

- Independent governance level varies: each RTO has Board oversight, but CAISO is state-appointed leading to concerns around independence; ISO-NE and SPP have fully independent boards, but vary in level of state authority and influence – SPP has shared decision making through RSC; ISO-NE only has advisory role for states leading to tensions between market rules and clean energy targets
    - SPP likely strongest governance model for Atlantic Canada due to balance of state/RTO powers
- US FERC oversight and Federal policy is essential for RTO formation and expansion + open access + dispute resolution – Canada lacks equivalent strong federal oversight body or authority
- CAISO / WEM governance – worth exploring how this could be a model for Atlantic?
- Cost allocation – what is the takeaway? This is complex, needs to be transparent and fair (e.g. Load share, zonal allocation)

Benefits and challenges

Key questions	ISO-New England	CAISO + WEM	SPP
Documented benefits? (eg cost savings, reliability, transmission growth, renewables integration)	Limited quantitative evidence of benefits. One study suggests modest net-benefits. Qualitative evidence of increased investment to capacity and resilience to major blackouts (e.g. Northeast Blackout of 2003). Various reports, not specific to any RTO, with that support claim of reliability benefits from deeper integration.	Limited quantitative evidence of benefits from initial implementation of CAISO. However, more recent studies project benefits from an expanded ISO/RTO footprint. WEIM claims $8+ billion in *gross* benefits since formation (market savings and environmental benefits). Various reports, not specific to any RTO, with that support claim of reliability benefits from deeper integration.	One report claims a cost-benefit ratio of 3.5 for transmission projects undergone by SPP between 2012-2014, though no counterfactual provided. SPP claims $2.25 billion in annual savings due to implementation of the Integrated Marketplace. Various reports, not specific to any RTO, with that support claim of reliability benefits from deeper integration.
Transmission growth			$3.4B new transmission projects from 2015-2019 (5.24 Benefit/cost ratio)
Major challenges encountered? How were they addressed?	Retail rates in the ISO-NE footprint are some of the highest in the US. Attributed mostly to natural gas supply being constrained during peak winter periods. Friction between ISO-NE and member states around its governance and lack of state-level decision making. Interim solutions were approved that allowed ISO-NE to pay generators to store up to 3 days of fuel on-site for at-risk periods. But a long-term solution has yet to be approved.[42]	2000-01 California Electricity Crisis, led to price spikes and blackouts. The cause is multi-factorial but much of the blame has been leveraged toward market design, that allowed manipulation of the markets and mandated participation without external hedging, and capped rates, which limited necessary investments. In the interim, California took over procurement of energy with a market redesign being implemented in 2009.	Winter storms in 2021 and 2022 pushed the SPP grid to it's limits. Comprehensive reviews were undergone with recommendations made and implementation currently underway.

[42] Divided FERC approves New England ISO short-term fuel security plan despite cost concerns (Source)

Key questions	ISO-New England	CAISO + WEM	SPP
Any notable course corrections?	See above, attempted implementation of policies to alleviate constrained gas demand.	See above.	Strong response to problems surrounding resource adequacy in winter.

Themes and takeaways:

- Limited independent and/or quantitative evidence of direct reliability or cost savings benefits – generally self-reported by RTOs, with lack of counterfactual and limited transparency around analysis.
- Strongest benefits case are around regional transmission and reliability (eg, greater resiliency to blackouts in ISO-NE, SPP response to 2021/22 winter storms)
- Regional market integration is not a silver bullet – RTOs still face structural constraints around fuel price volatility, extreme weather, and resource adequacy – highlighting the importance of physical infrastructure
- Transmission planning – SPP provides a strong benefit case study (3.5/1 benefit-cost ratio)
- Key questions for Atlantic Canada:
    - What is the objective of regional integration? This impacts the type of regional integration that is most likely to provide value.
    - Coordinated planning and regional transmission buildout can support greater reliability, resilience, and RE integration
    - Resource adequacy coordination can avoid firm capacity overbuild (e.g., gas plants)
    - Wholesale markets can support price transparency and operational efficiency – but evidence is mixed and market size and design are key

6. ISO-New England

6.1 Jurisdiction Information

6.1.1 Type

Regional Transmission Organization.

6.1.2 Member Jurisdictions

The ISO-NE footprint covers the entirety of the six New England states, with the exception of Northeast Maine[43]:

- Connecticut
- Maine
- Massachusetts
- New Hampshire
- Rhode Island
- Vermont

6.2 History

6.2.1 Pre-Formation

Like most of the US, the current ISO-NE footprint prior to formation was dominated by local vertically integrated utilities that operated as a monopoly over their respective territories. Following the *Great Northeast Blackout* in 1965, which cascaded across Ontario and 11 states, the Northeast Power Coordinating Council (NPCC) formed with a mandate to ensure system reliability in the Northeast[44]. Amongst this new focus on reliability in the region, the Northeast Power Pool (NEPOOL) formed in 1971 by the vertically integrated utilities in the six New England states[45].

Under NEPOOL, ownership of grid assets remained with these vertically integrated utilities, but the organization took on several responsibilities such as central dispatch of generation, settlement/billing, and joint planning.

6.2.2 Formation

6.2.2.1 Drivers

Amongst a global push for liberalization of the electricity sector, the US legislature passed the *Energy Policy Act of 1992*. Which expanded the authority of the existing Federal Energy Regulatory Commission (FERC) and exempted a new category of merchant generation that saw exemptions from earlier legislation.[46] Further market reforms were realized when FERC issued Order No. 888 and No. 889 in 1996. These orders required utilities to allow Open

[43] Electric Power Markets (Source)
[44] About NPCC (Source)
[45] Our History. ISO-NE (Source)
[46] Energy Policy Act of 1992 (Source)

Access to their transmission system, which enabled the sale of wholesale power across regions, as well as the creation of the Open Access Same-time Information System (OASIS) which served as the basis for reserving transmission capacity across entities[47].
The thesis behind this liberalization was driven by the perception that vertically integrated utilities led to higher rates due to lack of competition which led to lack of innovation and efficient operation, as well as regulated cost-of-service rate structuring led to an overbuild of capital-intensive assets that were paid for by the ratepayers[48].

6.2.2.2 Initial Scope

Independent System Operator – New England (ISO-NE) was formed in 1997 after the issuance of FERC Orders 888 & 889, which took over operation of the regional power grid from NEPOOL. In 1999, ISO-NE launched a wholesale market which covered all of New England except for Northern Maine. This market served as a 'spot market' to settle load imbalances resulting in variations from scheduled dispatch and bilateral trades. This market included wholesale energy as well as six reliability markets, such as stand-by power.[49]

6.2.2.3 Evolution

ISO-NE has seen several significant market reforms since its inception. The first occurred in 2003 with the implementation of the 'Standard Market Design' (SMD). This introduced Locational Marginal Pricing (LMP), Day-Ahead Market (DAM), and the Real-Time Market. This significantly changed the market operations from being primarily bilateral trades and utility self-dispatch with the market acting as a balancing tool, to the market being the primary method for scheduling and real-time balancing.[50]

LMP (based on eight pricing zones) provided more transparent pricing signals for transmission and generation based on congestion pricing. In addition, It allowed market participants to hedge against price volatility caused by a market running exclusively on real-time pricing.

In 2005, ISO-NE launched a Regulation Market and was also designated as a Regional Transmission Operator (RTO). Via Order No. 2000, FERC encouraged the formation of RTOs, outlining key functions and characteristics of these organizations and different strategies by which they might push organizations toward their formation. [51] ISO-NE already met many of these requirements but under their previous status as an ISO did not meet the requirements of impartiality in their governance structures as well as did not have full, exclusive control of the planning and operation of the transmission system itself. [52]

- In 2006, ISO-NE introduced the Forward Reserve Market.
- In 2008, the Forward Capacity Market was launched.

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[47] History of OATT Reform (Source)
[48] Electricity Restructuring : What Has Worked, What Has Not, And What Is Next (Source)
[49] New Era Begins in New England's Electricity Industry, 1999 (Source)
[50] Region's New Wholesale Electricity Marketplace Successfully 'Switched On' (Source)
[51] REGIONAL TRANSMISSION ORGANIZATIONS AND THE COORDINATION OF REGIONAL ELECTRICITY MARKETS: A REVIEW OF FERC ORDER 2000 (Source)
[52] ISO NEW ENGLAND TO BEGIN OPERATION AS REGIONAL TRANSMISSION ORGANIZATION, 2005 (Source)

- In 2013, the Strategic Planning Initiative was launched.
- In 2014, hourly supply and negative offers are implemented.
- In 2015, the FCM sees significant changes and the Redesigned Regulation Market goes into effect.
- In 2017, five minute settlement replaces hourly settlement in the real-time energy and reserves markets.
- In 2018, ISO-NE launches the price-responsive demand framework for demand response resources and the pay-for-performance (PFP) incentives.
- In 2019, the substitution auction is introduced to the FCM as well as the first competitive auction for transmission solutions.

6.3 Key Decisions

6.3.1 Governance

ISO-NE is a not-for-profit organization, governed by a 10-member Board of Directors with varied experience in finance, law, operations and regulation. They operate according to the ISO-NE Code of Conduct and By-Laws, which states that no member can have any financial interest in any ISO-NE market participant[53].

NEPOOL, which transitioned into a stakeholder advisory group at the inception of ISO-NE, runs a Participants Committee which serves as its primary forum for market participants[54]. Candidates for the ISO-NE Board of Directors must receive an endorsement from this committee.

In addition, NEPOOL runs several other committees and working groups in the following categories: Markets, Reliability, Transmission, Planning, and Industry Collaboration. These committees feed up to advise the Participants Committee.[55]

6.3.2 Regulatory

While utilities within its footprint are regulated by their respective state regulators, NE-ISO is overseen by the Federal Energy Regulatory Commission (FERC). FERC mandates the rules that ISO-NE must follow, which are described in the ISO-NE tariff. ISO-NE may make changes to this tariff following FERC review and approval under the Federal Power Act.[56]
In addition, ISO-NE must operate its systems in accordance with the North American Electricity Reliability Corporation (NERC), which itself is regulated by FERC, and the Regional Entity the Northeast Power Coordinating Council (NPCC). NERC produces continent-wide reliability standards whereas NPCC may supplement those standards with regional ones.[57]

6.3.3 Policy

Policy set by the state governments affects ISO-NE in a largely indirect manner. State governments have no real authority over the institution, though they engage with them

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[53] Board of Directors (Source)
[54] Participants Committee (Source)
[55] Committees and Groups (Source)
[56] Industry Standards, Structure, and Relationships (Source)
[57] About Us – NPCC (Source)

through in-depth stakeholder processes, such as through the New England States Committee on Electricity (NESCOE) and the New England Conference of Public Utilities Commissioners (NECPUC). However, state policies in New England, such as renewable energy mandates or incentives for Distributed Energy Resources affect the operations of ISO-NE and creates pressure for them to adapt to a changing grid.[58]

Federal policy affects ISO-NE more directly than state policy. However, there is still a degree of separation between the Federal government and FERC, which issues the binding orders that ISO-NE must follow. The Commissioners who govern FERC are appointed by the President of the US and serve 5-year terms.[59] Although these Commissioners do not take direct orders from the President or current administration, there is obviously a high likelihood any appointed Commissioner will implicitly align with that administration's goals. In addition, FERCs authority is statutory, meaning there is always potential for legislative amendment based on the priorities of Congress. Orders such as 745 (2011)[60], 841 (2018)[61], and 2222 (2020)[62], which respectively mandated ISO/RTOs allow the participation of demand response, energy storage, and DER aggregation in wholesale markets, are examples of orders that reflect modernized energy policy from the Federal government.

6.3.4 Cost Allocation

ISO-NE allocates costs to market participants through its FERC-approved tariff and in alignment with FERC orders[63]. Costs of different services/infrastructure have different cost allocation processes.

Transmission Cost[64]

- Projects, or portions of project costs, that improve reliability throughout the ISO's footprint will be socialized according to that region's load.
- Projects that do not improve reliability across the entire region are the responsibility of the transmission owner.

Administrative Costs

- Each market transaction includes a fee for administrative costs, such as the administration of the energy & reliability markets as well as planning.[65]

Load Costs[66]

- Wholesale Load
    - These are costs for the service of wholesale energy from suppliers to purchasers. Which includes energy, capacity, and ancillary services.

[58] New England states push for governance changes in ISO-NE, ahead of anticipated MOPR reform (Source)
[59] Meet the Commissioners – FERC (Source)
[60] Order 745 (Source)
[61] Order 841 (Source)
[62] Order 2222 (Source)
[63] Transmission, Markets, and Services Tariff – ISO-NE (Source)
[64] Transmission Cost Allocation (Source)
[65] RECOVERY OF ISO ADMINISTRATIVE EXPENSES (Source)
[66] Load Costs – ISO-NE (Source)

  - ISO-NE simply administers the markets in which these services are purchased on, it does not determine pricing itself.
  - For the Forward Capacity Market, costs are allocated to Load-Serving Entities (typically distribution companies) based on their contribution to zonal load.[67]

- Regional Network Load
  - These are costs related to the operation of the high-voltage transmission facilities operated by the ISO. Buyers and sellers of power on the network pay Regional Network Service (RNS) charges which are allocated to the transmission owners.
  - These charges are governed by the Open Access Transmission Tariff (OATT) and are billed to transmission customers according to their Regional Network Load (RNL). The RNL is defined as a customer's peak load coincident with the customer's appropriate Local Network monthly peak.[68]

- Emergency Energy
  - ISO-NE may purchase 'out of market' energy from neighbouring grids if emergency situations arise. In this case, market participants whose real-time behaviour deviated from what the market expected are allocated these costs.[69]

Generator Interconnection Costs

- Generators will generally pay all costs of interconnection that would not have otherwise occurred without. The exceptions are if a generator connects as part of a cluster, in which costs are distributed proportionally to each generator, or if part of the necessary interconnection infrastructure results in region-wide reliability upgrades, in which case costs are socialized.[70]

6.4 Benefits

The justification for the transition from NEPOOL to ISO-NE follow the typical goals of liberalization across the globe and the US: Increased competition leads to innovation and efficiency gains (both system wide and plant level).
However, the observation of these benefits largely remains qualitative, with limited quantitative analysis proving net benefits.

6.4.1 Reliability/Resilience

During the 2003 Northeast Blackout, the majority of the region remained in-service. ISO-NE credits this to its operating practices and operator training, with a 34% increase in new generating plants increasing reliability.

[67] Market Rule 1 – Section 13 – ISO-NE (Source)
[68] Monthly Regional Network Load Cost Report September 2025 (Source)
[69] Market Rule 1 – ISO-NE (Source)
[70] OATT Schedule 11 – ISO-NE (Source)

ISO-NE runs centralized transmission planning for the region as well as central dispatch. It produces several regular reports to inform this process, which improves access to centralized information.[71]

The Energy Policy Act of 2005 modernized reliability standards in the US, which were administered by NERC and its regional partners like the NPCC. Since the implementation of these standards, ISO-NE has high levels of reliability in their footprint. However, recent NERC reports highlight some potential future reliability challenges under low-probability high-consequence scenarios. However, these types of concerns are also present in neighbouring market-based or vertically integrated regions, such as Atlantic Canada, and NY-ISO. In contrast, Ontario (a partially liberalized jurisdiction) and Quebec (the largest vertically integrated region in Canada) are determined to have no major reliability risks.[72] This demonstrates that high reliability is not necessarily determined by market structure.

6.4.2 Cost Savings

Direct quantitative analysis of cost-savings as a result of liberalization in the ISO-NE region is limited. One 2007 study suggests that there were modest net-benefits over it's 18-year analysis[73].

In comparison to other regions in North America, New England region has higher than average retail electricity prices. However, once again, this is in comparison to both liberalized jurisdictions and regions with high degrees vertical integration.[74][75] Commentary on this has blamed a variety of factors such as natural gas prices, older infrastructure, and/or clean energy policies.[76]

6.5 Challenges

Electricity prices in New England are tightly coupled to natural gas[77]. ISO-NE itself has reported that natural gas can become heavily constrained during peak winter periods.[78] In addition, NE-ISO has relatively strict scarcity pricing mechanisms through its pay-for-performance (PFP) framework, which resulted in the highest scarcity pricing of any market in the US.[79]

Further challenges have been observed in the governance of ISO-NE. Implementation of FERC orders intended to align markets with state energy policies led to friction between the states and ISO-NE. This led to questions around governance within ISO-NE, with states

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[71] Plans and Studies (ISO-NE) (Source)
[72] 2024–2025 Winter Reliability Assessment (NERC) (Source)
[73] A cost-benefit assessment of wholesale electricity restructuring and competition in New England (Source)
[74] US Electricity Profile 2024 (EIA) (Source)
[75] 2024 Comparison of Electricity Prices in Major North American Cities (Hydro Quebec) (Source)
[76] Mapped: The Average Cost of Electricity by U.S. State (Source)
[77] Implications of electricity and gas price coupling in US New England region (Source)
[78] Winter 2025 Quarterly Markets Report (ISO-NE) (Source)
[79] 2024 ASSESSMENT OF THE ISO NEW ENGLAND ELECTRICITY MARKETS (Source)

currently acting primarily as stakeholders. Some state regulators argued that state institutions should have some sort of vote on decision making, not just be consulted.[80]

7. Southwest Power Pool (SPP)

7.1 Jurisdiction Information

7.1.1 Type

Regional transmission organization (RTO)

7.1.2 Member Jurisdictions

SPP covers the majority of the following jurisdictions as part of its main footprint:

- North Dakota
- Nebraska
- Kansas
- Oklahoma

In addition, it provides full footprint services in parts of Montana, Minnesota, Iowa, Missouri, Arkansas, Texas, Wyoming, Louisiana, and New Mexico.

SPP provides various additional services across the Western Interconnection. This includes[81]:

- **The Western Energy Imbalance Service (WEIS) Market:** Provides services in parts of Montana, Wyoming, Utah, Colorado, New Mexico, Texas, and Arizona[82].
- **Western Reliability Coordination:** SPP acts as the Reliability Coordinator for various customers in the Western Interconnection.
- **Western Resource Adequacy Program (WRAP):** SPP serves as program operator on behalf of the Western Power Pool for its resource adequacy program.
- **RTO West:** Several utilities in the Western Interconnection have committed to joining SPP as full RTO members, with a targeted .[83]
- **Markets+:** SPP is in the process of implementing 'Markets+', which will provide additional market services to non-RTO members like WEIS. This will include a day-ahead market and real-time dispatch.

7.2 Pre-Formation

Just like the rest of the US, the region the SPP now serves was dominated by vertically integrated regional utilities prior to its formation. The SPP, despite its name, is a fully

[80] New England states push for governance changes in ISO-NE, ahead of anticipated MOPR reform (Source)
[81] Western Services (Source)
[82] Western RC Services (Source)
[83] FERC ER24-2184-000 (Source)

modernized Regional Transmission Organization. Like ISO-NE it originally formed as a 'power pool' but did not change its name or form a new organization when transitioning to an ISO.

7.3 Formation

7.3.1 Drivers

In the face of massive industrial demand for aluminum during World War II, 11 utilities established the organization to help meet the associated increased electricity demand in 1941.[84]

7.3.2 Initial Scope

As a power pool, during WWII the SPP focus was simply coordinated reserves, dispatch, and transmission during this period.

7.3.3 Evolution

Following the war, the SPP participants chose to retain the organization due to its obvious benefits. Its role began to evolve rapidly throughout the decades:

Post-war to 1960

- Transition from an ad-hoc body to a standing regional coordination organization.

1960-1970

- SPP begins act as a 'regional reliability organization' and formalizes reliability criteria, coordination of interconnections, and the development of a regional system planning model.
- Grows to 26 participants.

1970-1980

- Increased environmental awareness in the US, the 1973 oil crisis, and the Three Mile Island incident spurs additional layers of regulation that power system owners must consider.
- The Public Utility Regulatory Policy Act (PURPA) requires utilities to purchase excess energy from self-generation assets at avoided costs, encouraging new entries into the wholesale electricity market.
- The South Central Systems of the North American Power Systems Interconnections Committee merges with the SPP, further integrating participants.
- Computerization increases complexity of modelling and data collection done by SPP.

1980-1990

- A heatwave in Southern US leads to increased demand and lower production from nuclear and hydro plants for environmental reason, causing reserves to diminish. In addition, the increased complexity of the regulatory regime and the oil crisis leads to the first rise in electricity rates in decades. This encourages the practice of Integrated Resource Planning and increases the practice of purchasing and selling power on the wholesale market.

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84 The Power of Relationships (Source)

- SPP encourages participants to provide them with hourly prices and capacity to reduce friction in market purchases.
- SPP expands its initiatives to include operator training, enhance its modelling capabilities, and expand its telecommunications networks.

1990-2000

- Formation of the Operating Reserve Program.
- Energy Policy Act of 1992 is passed, setting the stage for competitive wholesale generation. In response, SPP produces a strategic plan to prepare for coming changes. This leads to the incorporation of SPP as the Southwest Power Pool Inc in Arkansas and the formation of the Transmission Access Committee.
- SPP expands to 53 members.
- Creation of the 'Next-Hour Energy Exchange' in 1996 using the "rates, terms and conditions of the Western Systems Power Pool (WSPP) agreement" allowing for rapid deployment of the market.
- FERC Orders 888 and 889 are issued in 1996 leading to Open Access Transmission, unbundling of transmission and generation services, the formation of the Open Access Same-Time Information System (OASIS), and encouraging the formation of Independent System Operators (ISOs).
- SPP becomes a 'regional security coordinator' under the North American Reliability Corporation (NERC). A security center is created to provide a real-time view of utility operations.
- The SPP board votes to implement a regional transmission tariff, leading to the withdrawal of several important members. However, this leads to smoother consensus making and acts as a 'slingshot' for the development of a modern RTO.

2000-2010

- After FERC Order 2000 encouraged organizations to form Regional Transmission Organizations, with a slightly broader and different scope than the typical ISOs it encouraged in previous orders, SPP made three attempts to file with FERC to form an RTO. On October 4, 2004, FERC approved SPPs RTO status and affirmed they met all the requirements.
- The California Electricity Crisis draws attention to the potential issues of poor market design in wholesale markets and the Northeast Blackout of 2003 prompts the passing of the 'Energy Policy Act of 2005' which expands FERCs powers and the enforcement of NERC standards.
- SPP implements an Energy Imbalance Service (EIS) market over its footprint in 2007, intending to implement incremental market services rather than an entire integrated system at once. The market runs every 5 minutes with settlement prices averaged over each hour.
    - Estimates put member benefits at $103 million in the first year of operation with a cost of $33 million.
- SPP becomes a Regional Entity under the new rules giving NERC authority to enforce reliability standards. SPP forms a separate entity (SPP Regional Entity) with separate staff and board to fulfill this role.

- SPP expands initiatives for transmission system planning for reliability and economic purposes, requiring cost allocation methodologies to distribute the costs based on benefits.
- New members broaden SPPs footprint by 30%

2010-2020

- The Integrated Marketplace is implemented in 2014 and includes: A Day-Ahead Market with Transmission Congestion Rights, a Reliability Unit Commitment Process, a Real-Time Balancing Market, and price-based Operating Reserve procurements.
- SPP forms as a Consolidated Balancing Authority, replacing 16 existing BAs in the SPP footprint.
- Wind energy rises to 16% of generation in the SPP footprint by 2016.
- SPP footprint nearly doubles with new market participants and completes its first international transaction in 2015 with SaskPower.
- The SPP-RE dissolves due to the misalignment between the SPP RTO footprint and the reliability entities footprint because of the rapid growth of the RTO. This resulted in the expansion of the footprint of the adjacent reliability regional entities: Midwest Reliability Organization (MRO) and SERC Reliability Corporation (SERC).

2020-Present

- SPP launches the Western Energy Imbalance Services (WEIS) market. This market provides energy imbalance services to non-RTO participants in Colorado, Utah, Montana, and Arizona.[85]

7.4 Key Decisions

7.4.1 Governance

SPPs Board is comprised of up to 10 positions, all of which must be independent from market participants and each other. Member are nominated by the Corporate Governance Committee (CGC). Including the CGC, there are four other Board committees that report to it: Oversight Committee, Finance Committee, Human Resources Committee, and Strategic Planning Committee. In addition, there is a Members Committee which is comprised of representatives from market participants and technical committees that report to the central Markets and Operations Policy Committee, all which provide input to the SPP Board.

Adjacent to the Board is the SPP Regional State Committee (RSC) which shares decision making powers with the Board. The RSC is made up of state commissioners in states that SPP operates in. It includes two subcommittees: Cost Allocation Working Group and RSC/OMS Liaison Committee. The CAWG is the primary group for developing cost allocation frameworks for the RTO and the Liaison Committee allows states where the Midcontinent Independent System Operator (MISO) to ensure policy alignment between the two RTO/ISOs.

[85] Western Energy Imbalance Service Market (Source)

In addition to these groups, SPP operates a robust stakeholder process with numerous forums and advisory groups.[86]

WEIS Governance

The SPP Board retains full administrative control over the WEIS Market. However, they operate a Western Markets Working Group (WWMG) as a forum for market participants of WEIS.

7.4.2 Regulatory

While utilities within its footprint are regulated by their respective state regulators, SPP is primarily overseen by the Federal Energy Regulatory Commission (FERC). FERC mandates the rules that SPP must follow, which are described in the SPP tariff. SPP may make changes to this tariff following FERC review and approval under the Federal Power Act[87].
In addition, SPP must operate its systems in accordance with the North American Electricity Reliability Corporation (NERC), which itself is regulated by FERC, and the regional entities that its footprint crosses, which includes both MRO and SERC after the dissolution of SPP – Regional Entity[88].

7.4.3 Policy

Federal policy affects SPP more directly than state policy. However, there is still a degree of separation between the Federal government and FERC, which issues the binding orders that SPP must follow. The Commissioners who govern FERC are appointed by the President of the US and serve 5-year terms. Although these Commissioners do not take direct orders from the President or current administration, there is obviously a high likelihood any appointed Commissioner will implicitly align with that administration's goals.

In addition, FERCs authority is statutory, meaning there is always potential for legislative amendment based on the priorities of Congress. Orders such as 745 (2011), 841 (2018), and 2222 (2020), which respectively mandated ISO/RTOs allow the participation of demand response, energy storage, and DER aggregation in wholesale markets, are examples of orders that reflect modernized energy policy from the Federal government.

7.4.4 Transmission Planning

SPP's transmission planning process is known as the Integrated Transmission Plan (ITP). It occurs on an annual basis for a 10-year transmission expansion plan timeline and every 5 years for a 20-year timeline. The ITPs include various studies based on NERC standards, load forecasts, and other assumptions related to policies and generation market trends.

The 10-year ITP is reviewed by the Markets and Operations Policy Committee (MOPC) and it is approved by the SPP Board. The 20-year ITP is reviewed by various committees and working groups such as the Economic Studies Working Group, Transmission Working Group, Cost Allocation Working Group, Strategic Planning Committee, Regional State Committee, and MOPC.[89]

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[86] Governance Structure and Practices in the FERC Jurisdictional ISOs/RTOs (Source)
[87] Legal and regulatory – Tariff (Source)
[88] FERC approves elimination of SPP regional entity (Source)
[89] Integrated Transmission Planning (Source)

7.4.5 Cost Allocation

Cost allocation is the responsibility of the Regional State Committee (RSC), made up of representatives from each participating states regulator commission. The RSC is assisted by the Cost Allocation Working Group (CAWG), which is made up of technical staff from the relevant regulatory bodies.

SPP's operational costs are recovered via tariff rates. These rates are based on the Net Revenue Requirement determined by SPP and is charged a $/MWh rate, charged based on a Load Responsible Entity's contribution to annual system load. The services are broken down into four services and are billed separate rates according to their costs. The services include system control, Transmission Congestion Rights administration, Market Clearing and Market Facilitation.[90]

SPPs process to allocate transmission costs is a relatively simple heuristic called the 'Highway/Byway' cost methodology. It was proposed by the Synergistic Planning Project Team (SPPT) and then subsequently approved by the RSC in 2009. This methodology allocates costs for transmission facilities to participants either region-wide or in the appropriate zone based on voltage levels of the project. For projects 300kV and above, all costs are allocated region wide. For projects between 100kV and 300kV, 33% of costs are regional and 67% are zonal. For anything below 100kV, all costs are zonal[91].

WEIS Cost Allocation

WEIS costs are allocated to participants based on 'net energy for load', similar to the standard SPP tariff. Participants are simply charged a universal "postage-stamp" rate based on their proportional load. [92]

7.5 Benefits

7.5.1 Reliability/Resilience

In addition to operating according to NERC/Regional Entity standards, SPP also operates its own Resource Adequacy program. Each Load Responsible Entity (LRE) in SPP's footprint must demonstrated that it has sufficient capacity for its forecasted peak demand and the Planning Reserve Margin (PRM). The PRM is set by SPP using Loss-of-Load Expectation (LOLE) studies, generator forced outage rates, load forecasting, and weather modeling. Resources are accredited with capacity depending on their fundamental characteristics. Wind and solar utilize Effective Load Carrying Capability (ELCC) based methodologies whereas thermal resources use forced outage rates. SPP will charge deficiency payments to any LRE that is short on its capacity obligations.[93]

There is no quantitative analysis that has determined that load in the SPP footprint has been served more reliably by the organization than by a counterfactual scenario with no RTO. However, there are many reports and studies that demonstrate that many of the features of

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[90] 2025 SPP Budget (Source)
[91] The History of the Regional State Committee (Source)
[92] Docket Nos. ER21-3-000, ER21-4-000 (Source)
[93] 2025 SPP Winter Season Resource Adequacy Report (Source)

RTOs, centralized reliability organizations, or other centralized market services (like the WEIS) do provide reliability benefits[94] [95] [96]. These include:

- **Reserve pooling over wider regions**: Reduces individual Balancing Authority reserve requirements and enhances regional ability to integrate renewables.
- **Centralized dispatch**: Assists in reducing reserves and balancing burden
- **Improved resilience** to extreme weather events
- **Consistent Reliability Standards**: Leads to faster identification and correction of systemic risks

7.5.2 Cost Savings

A report published in 2022 by SPP[97], undergone by Brattle Group, estimated several benefits from SPPs transmission projects placed in service between 2012-2014, with benefits projected over 40 years. These included:

- Estimated NPV of $16.6 billion from production cost savings
- Benefit-Cost Ratio of 3.5
- Reduced transmission congestion
- Loss reduction
- Increased wind integration
- Enhanced reliability

However, it should be noted that the counterfactual for these benefits was a scenario in which none of these projects were built. It may not be accurate to claim that the projects in question, or similar ones, would have never been built without an RTO like SPP.
In addition, in 2024 SPP published a press-release[98] that claimed that since the implementation of the Integrated Marketplace in 2014 that it had resulted in $10.2 billion of benefits to members, with $2.25 billion in annual savings in 2023. However, the analysis that reached these values is not public.

7.6 Challenges

The SPP has a history of over 80 years with a lot of transformation over this time. The organization faced multiple periods of rapid growth and challenges.

- **Formation of RTO/RTG**: The evolution of the SPP from a power-pool to RTO took several attempts and many years of staff effort to manage. This included 7 years of developing itself as a Regional Transmission Group (RTG) and then 5 years to finally become an RTO, after RTG status became obsolete.

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[94] Balancing Area Coordination: Efficiently Integrating Renewable Energy Into the Grid (Source)
[95] Bulk System Reliability for Tomorrow's Grid (Source)
[96] Operating Reserve Reductions from a Proposed Energy Imbalance Market with Wind and Solar Generation in the Western Interconnection (Source)
[97] The Value of Transmission (Source)
[98] SPP marks a decade of Integrated Marketplace and more than $10.2 billion in savings (Source)

- **Resource Adequacy/Extreme Weather**: A winter storm in February 2021 bushed the SPP's grid to its limits, with both supply and demand issues. The RTO had to conduct region-wide load shedding for the first time in its history. [99]
- **Expansion in the West and competition with CAISO**: SPP is competing with CAISO to provide market services in the western interconnection. Both currently operate an energy imbalance market with upcoming Day-Ahead Markets being implementing. Both CAISO and SPP offer similar products but with different governance models. CAISO has devolved authorities to stakeholders in its WEIM market but many of the decisions on the path to further integration in the west still lay with the California government. SPP provides much stronger interregional representation through the RSC, with significant decision-making powers delegated to state regulators since its inception.
- **Divergent energy policies across states**: The strong state decision-making power can create tension and slow down decision-making processes when disagreement occurs between states. There are significant examples of this, such as the dissent amongst states surrounding implementation for the Highway/Byway Cost Allocation[100].

[99] A Comprehensive Review of Southwest Power Pool's Response to the February 2021 Winter Storm (Source)
[100] Commissioner Christie's Dissent to SPP Highway/Byway Cost Allocation Exception (Source)

8. California Independent System Operator (CAISO)

8.1 Jurisdiction information

8.1.1 Type

Independent system operator (ISO)

8.1.2 Member Jurisdictions

CAISO operates most of the wholesale grid in California as well as a small portion of bordering areas of Nevada. In addition, CAISO operates the Western Energy Imbalance Market (WEIM). The WEIM includes utilities in states such as Idaho, Montana, Nevada, New Mexico, Oregon, Washington, Texas, and even the province of British Columbia.

8.2 Pre-Formation

As with the rest of the US, prior to the formation of CAISO, electricity utilities were largely vertically integrated with limited open access to transmission and electricity trading dominated by bilateral trades. As with liberalization writ large in the US, this was driven by a belief that the status quo of vertically integrated utilities led to higher prices and less innovation.

8.3 Formation

8.3.1 Drivers

California was the first state to restructure its electricity market[101]. Following the Energy Policy Act of 1992 and subsequent FERC Order 888 in 1996, which prompted the beginning of electricity sector liberalization, the California legislature passed Assembly Bill 1890, which mandated the creation of an independent system operator[102].

8.3.2 Initial Scope

As with most new ISOs at the time, CAISOs initial role was to operate the high-voltage transmission grid on behalf of the asset owners (Investor Owned Utilities – IOUs). AB 1890 enforced open access rules to this grid. In addition, they ran the wholesale market, known as the Power Exchange (PX). This was an hourly spot market and IOUs were mandated to sell the majority of their power on the market. In addition, the bill mandated the reduction of small commercial and residential customers by 10% and then a subsequent freeze.

8.3.3 Evolution

Only 6 years after the initial market reforms, the state experienced the notorious 2000-2001 California electricity crisis. This was characterized by massive wholesale price spikes and even rolling blackouts. The cause can be attributed to a variety of factors such as a capped retail

[101] History – CAISO (Source)
[102] Provision of AB 1890 (Source)

rates, capacity deficits, poor market design, and gaming by merchant generators. The latter of which most famously contributed to the adjacent Enron scandal.[103] The state's immediate response was to transfer wholesale power procurement to the Department of Water Resources, allowing them to make long-term purchasing contracts while CAISO[104], with FERC oversight, updated market rules such as nodal pricing.
Some of the major changes include:

- Implementation of the Market Redesign and Technology Upgrade (MRTU) in 2009.
  - This included Locational Marginal Pricing (LMP), day-ahead and real-time markets. In addition, the new market framework allowed the optimization of energy, ancillary services, and grid congestion.[105]
- Expansion of CAISO footprint to include Valley Electric Association in Nevada in 2013.
- Launch of the Western Energy Imbalance Market (WEIM) service in 2014.
  - The WEIM acts as a balancing market for surplus energy for participating entities. It started with 2 entities in 2014 but expanded
- The launch of a 'Flexible Ramping Product' in 2016 to meet the needs of a system with increased renewable penetration.[106]
- Launch of Reliability Coordinator services (RC West) in 2019.
  - As a NERC certified RC, CAISO runs contingency analysis and reliability screening over most of the west.

8.4 Key Decisions

8.4.1 Governance

CAISO is led by a Board of Governors appointed by the Governor of California. In addition to the Board, there are several committees that influence CAISO's decision making, such as: the Audit Committee, Market Surveillance Committee, and Department of Market Monitoring Oversight Committee. In 2009, CAISO launched their new market and technology platform. However, the state settled into a more hybrid model (popular in most ISO/RTO jurisdictions now) where most of the energy is procured by utilities via long term contracts but is still dispatched by CAISO. These procurements are governed by the California Public Utilities Commission which sets resource adequacy requirements.

WEIM Governance

The WEIM, as well as the future Extended Day Ahead Market (EDAM), is governed jointly by the CAISO Board of Governors as well as the Western Energy Markets (WEM) Governing Body.

This Governing Body is made up of 5 members that must be independent of market participants. Election of these members undergoes a nomination process that includes stakeholders (utilities, transmission owners, public interest, regulators, etc.) who hold the primary voting power during the nomination process, with both the WEM Governing Body

[103] The California Electricity Crisis: Causes and Policy Options (Source)
[104] Assembly Bill 1 of the 1st Extraordinary Session of 2001-2002 (Source)
[105] Background on MRTU and Its Implementation Timeline (Source)
[106] Tariff Amendment to Implement Flexible Ramping Product (Source)

and the CAISO Board of Governors acting as non-voting representatives. These nominees are then approved by the WEM Governing Body.[107][108]

Since it's inception, WEM governance has undergone several changes. The West-Wide Governance Pathways Initiative was launched from regulators across the western states to devolve some of the authority from CAISO. Step 1 of their recommendations was approved by the CAISO Board, WEM governing body, and FERC in 2024. This elevated the decision-making authority of the WEM Governing Body in matters exclusively related to the WEM to 'primary authority', where it was simply 'joint authority' with the CAISO Board previously. It also made some other amendments to the dispute resolution process and public interest provisions.[109]

8.4.2 Regulatory

While utilities within its footprint are regulated by their respective state regulators, CAISO is primarily overseen by the Federal Energy Regulatory Commission (FERC). FERC mandates the rules that CAISO must follow, which are described in the CAISO tariff. CAISO may make changes to this tariff following FERC review and approval under the Federal Power Act[110].

In addition, CAISO must operate its systems in accordance with the North American Electricity Reliability Corporation (NERC), which itself is regulated by FERC, and the Regional Entity the Western Electricity Coordinating Council (WECC). NERC produces continent-wide reliability standards whereas WECC may supplement those standards with regional ones.[111] CPUC also supplements these standards with resource adequacy standards for Load Serving Entities (LSEs). These do not apply to CAISO but the two organizations coordinate on resource adequacy through system reliability studies.[112] If the LSEs do not acquire an adequate amount of capacity, CAISO may procure additional capacity through the 'Capacity Procurement Mechanism' to ensure system resource adequacy.[113]

The California state legislature also plays a significant role in regulating CAISO. As mentioned, its creation was prompted by AB1890. In addition, State Bill 350 (2015) directed CAISO to study the possibility of expansion to other western states. It explicitly enabled a potential pathway for CAISO to transform to a regional entity if it were to be in the best interests of California.[114]

8.4.3 Policy

Like with other ISO/RTOs, state policy largely affects CAISO's operations in an indirect manner. However, unlike most other ISO/RTOs, CAISO is a creature of state statute and its expansion into other markets is thus constrained by the state (see SB350). In addition to the provisions regarding CAISO's expansion, SB350 the "Clean Energy and Pollution Reduction Act of 2015" mandated that 50% of California's electricity be produced by renewable sources

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[107] Charter for WEIM and EDAM Governance (Source)
[108] Selection Policy for the WEM Governing Body (Source)
[109] West-wide Governance Pathways Initiative overview (Source)
[110] Legal and regulatory – Tariff (Source)
[111] WECC Standards (Source)
[112] Resource Adequacy Homepage (Source)
[113] Presentation - CAISO Resource Adequacy Overview (Source)
[114] 2024 California Code Public Utilities Code – PUC DIVISION 1 (Source)

by 2030.[115] The subsequent increase in renewable penetration materially affects CAISO's operations and led to the creation of new market products, as mentioned previously.

Federal policy affects CAISO more directly than state policy. However, there is still a degree of separation between the Federal government and FERC, which issues the binding orders that CAISO must follow. The Commissioners who govern FERC are appointed by the President of the US and serve 5-year terms. Although these Commissioners do not take direct orders from the President or current administration, there is obviously a high likelihood any appointed Commissioner will implicitly align with that administration's goals. In addition, FERCs authority is statutory, meaning there is always potential for legislative amendment based on the priorities of Congress. Orders such as 745 (2011), 841 (2018), and 2222 (2020), which respectively mandated ISO/RTOs allow the participation of demand response, energy storage, and DER aggregation in wholesale markets, are examples of orders that reflect modernized energy policy from the Federal government.

8.4.4 Transmission Planning

CAISO runs an annual Transmission Planning Process (TPP) in collaboration with the California public Utilities Commission (CPUC) and the California Energy Commission (CEC). CPUC develops 'resource forecasts' which identify resource rich areas for development while CEC leads customer load forecasting. As part of the TPP, CAISO not only investigates transmission solutions but also Non-Wires Alternatives (NWAs), such as demand response or energy efficiency[116]. The TPP runs in three phases:

Phase 1: Development of study plan

- Finalizing a study plan dependent on the assumptions developed by CEC and CPUC.

Phase 2: Technical Studies

- CAISO performs studies to identify solutions and conduct stakeholder engagement.

Phase 3: Procurement

- Once the CAISO board approves transmission plan, CAISO then performs competitive solicitation for the new transmission facilities identified in the plan to be built and owned by proponents.

8.4.5 Cost Allocation

CAISO allocates costs to market participants through several mechanisms[117]:

Grid Management Charges (GMC)

- The GMC covers general operating costs for CAISO. It is allocated to market participants based on four different service charges. These are charged to participants on a volumetric ($/MWh) basis.
    - Market Services Charge
    - Systems Operations Real Time Dispatch
    - System Operations Balance Authority Area Services

[115] California Senate Bill 350 (Source)
[116] The California ISO's Transmission Planning Process – A Brief Overview (Source)
[117] CAISO Fifth Replacement FERC Electric Tariff (Source)

- Congestion Revenue Rights Services

Transmission Access Charge (TAC)

- CAISO divides the grid into TAC areas based on control areas of the original Transmission Owners.
- FERC approved transmission revenue requirements are set for transmission facilities.
- Charged on a volumetric basis to LSEs ($/MWh) to any entity that 'withdraws' power (i.e. LSEs).

Interconnection and Network Upgrade Costs

- Interconnection Customers (IC) pay 100% of study and interconnection facility costs.
- If a network upgrade is determined to be necessary to interconnect a particular participant, then the IC will pay dependent on what drives the upgrade. Reliability network upgrades are paid upfront by the IC with reimbursement occurring if it is later found to have broader system benefits. Deliverability network upgrades (to ensure the generator counts toward resource adequacy during stressed system conditions) are allocated in proportion to the deliverability capacity the generator receives.

Capacity Procurement Mechanism (CPM)

- This is the emergency backstop when LSEs may fail to procure enough capacity to meet resource adequacy obligations. CAISO will procure capacity on behalf of the system, outside the typical bilateral markets. Costs are allocated to the deficient LSEs based on their share of the shortfall.

8.4.6 WEIM Cost Allocation

The WEIM Cost Allocation is also detailed in CAISO's FERC Tariff. There are several costs associated with participation in the WEIM:

- Administrative/Operating Costs
    - Based on MWh of WEIM activity (i.e. what an entity traded, only on the WEIM).
- Governance Costs
    - Fixed by participation.
- Implementation Costs
    - Fully paid for by the participant.

8.5 Benefits

8.5.1 Reliability/Resilience

Soon after the formation of CAISO, California faced the 2000-2001 Electricity Crisis. Skyrocketing wholesale prices and blackouts prompted the use of emergency powers and market reforms to stabilize the system[118]. A review of the crisis by the Public Policy Institute of California stated this[119]:

[118] The California Crisis Timeline (Source)
[119] The California Electricity Crisis: Causes and Policy Options (Source)

Overall, policymakers face a choice between the greater stability, reliability, and administrative feasibility provided by public ownership or regulated regimes versus the prospects for greater efficiency gains through competitive markets.

CAISO publishes the *Grid Emergencies History Report*[120] which shows that bulk system reliability has clearly improved significantly since the electricity crisis. Though the data does not suggest ever improving reliability under the ISO model, particularly in recent years with significant numbers of transmission emergencies occurring. However, there is no quantitative data for the pre-CAISO era to compare reliability to nor is it truly possible to fully disaggregate the effect of market liberalization from other potential factors. Commentary and analysis of the recent reliability woes suggest a mixture of factors such as increased wildfires & extreme weather, firm capacity retirements, and integration of renewables as compounding factors[121][122][123].

However, a recent study by the Stanford Climate & Energy Policy program[124] which simulated the Western Interconnection under an expanded RTO/ISO footprint during periods of grid stress suggests that greater regionalization leads to better reliability during extreme events. The reasons attributed to this result are largely intuitive:

- Pooling of diverse resources over larger geographical areas during stress events leads to reduced hours at risk, this is particularly important as renewable penetration increases.
- ISO/RTOs provide greater transparency through day-ahead and real-time markets of the availability of resources over a wider area.

These concepts are corroborated by an NREL paper[125] examining the potential benefits of the WEIM. It states:

An EIM takes advantage of the reduction in wind and solar generation variability that is achieved via the geographic diversity inherent across a wide area. An EIM also allows a broader geographic range of generation resources to contribute to the economic balancing of generation and load.

8.5.2 Cost Savings

Similar to reliability, there is limited data that suggests that market liberalization led to significant cost savings in California or the US more widely. The California Electricity Crisis is estimated to have increased energy prices during its period by $40 billion, not including the costs of blackouts or their downstream effects. One 2007 study suggests that there were

[120] Grid Emergencies History Report (Source)
[121] Root Cause Analysis Mid-August 2020 Extreme Heat Wave (Source)
[122] ASSESSING THE IMPACT OF WILDFIRES ON THE CALIFORNIA ELECTRICITY GRID (Source)
[123] 2025 Summer Reliability Assessment – NERC (Source)
[124] GRID REGIONALIZATION IN THE WEST: RELIABILITY BENEFITS FROM INCREASED COOPERATION IN ELECTRICITY MARKETS AND OPERATIONS (Source)
[125] Examination of Potential Benefits of an Energy Imbalance Market in the Western Interconnection (Source)

modest net-benefits over its 18-year analysis[126] and another 2009 study[127] suggests $1 billion in annual savings from restructuring due to increase efficiency, but that this has not necessarily translated to lower retail prices:

> *Regional grid integration and RTO markets have increased the efficiency of the wholesale electric market, by lowering barriers to trade and increasing the utilization of low-cost generation resources. If we take as a representative figure $1 billion per year in long-term national annual savings, this works out to an average cost savings of roughly two cents per kilowatt-hour, assuming 100 million megawatt-hours of annual United States demand.*
>
> *Operating efficiency of baseload units with low marginal costs has been improved by regional grid integration, but the efficiency of peaking units (particularly natural gas generation) with high marginal costs has decreased.*
>
> *The evidence on retail prices is the most difficult to summarize, since there are equally good estimates that consumer prices have increased and decreased in states that have chosen restructuring. Further, the mix of regulatory interference and fuel-price effects make it extremely hard to determine if restructuring or some other influence is largely responsible for the observed changes in retail prices.* ***What can be taken from the existing literature is that, to date, the estimated retail price effects (positive or negative) associated with restructuring have been reasonably small****.*

However, two forward-looking studies suggest that production costs for an expanded footprint would have net financial benefits compared to the counterfactual.[128] [129] Additionally, Western Energy Markets publishes a quarterly benefits report that quantifies gross benefits of the WEIM[130]. As of writing, it is estimated that the market has brought $7.82 billion in gross benefits since its 2014 inception. However, no number is provided for net benefits.

It should be noted that California has the second highest retail electricity rates in the US, next to Hawaii.[131] Research and commentary has attributed this to wildfire risk mitigation, Renewable Portfolio Standards, legacy rooftop solar programs, and natural gas prices.[132][133][134]

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[126] A cost-benefit assessment of wholesale electricity restructuring and competition in New England (Source)
[127] MEASURING THE BENEFITS AND COSTS OF REGIONAL ELECTRIC GRID INTEGRATION (Source)
[128] Regional Coordination in the West: Benefits of PacifiCorp and California ISO (Source) Integration
[129] B 350 Study: The Impacts of a Regional ISO-Operated Power Market on California (Source)
[130] WEIM benefits (Source)
[131] Mapped: The Average Cost of Electricity by U.S. State (Source)
[132] U.S. State Electricity Resource Standards (Source)
[133] Factors influencing recent trends in retail electricity prices in the United States (Source)
[134] 2024 SENATE BILL 695 REPORT (Source)

8.6 Challenges

The initial implementation of CAISO and the subsequent power crisis represented significant challenges but ultimately resulted in lessons learned for RTO/ISOs across the United States. Unlike some of the pre-existing interstate RTOs, CAISO was borne from state legislation and faces barriers in expanding to other states. Regardless, with its expansion into Nevada and offering of market services in other areas of the Western Interconnection, this is clearly not insurmountable.

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