

Grid Integration in the West: Bulk Electric System Reliability, Clean Energy Integration, and Economic Efficiency



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1. INTRODUCTION

The electricity system in the Western Interconnection is in the midst of unprecedented change. State and federal regulations that directly and indirectly require decreases in coal-fired generation and increases in the utilization of centralized and distributed renewable energy resources, storage, demand response, and energy efficiency are projected to generate significant near and long-term environmental benefits. However, as the September 2011 Southwest outage¹ convincingly demonstrated, there are deficiencies in Bulk Electric System (BES) situational awareness, operational practices, and regional coordination that are creating reliability threats for the region. The outage, which was caused by factors completely independent of renewable generation, provided a foreshadowing that the electricity system that has performed with remarkable reliability over time may not be capable of resiliently adapting to changes in demand patterns and generation resources unless there are changes in how the system is planned and operated.

It is fortuitous that activities to enable ongoing reliability with or without renewable generation also have the potential to greatly benefit system economics and clean energy resource integration. This is a unique and critically important era in the history of the electricity system in the Western U.S. and a transient opportunity to make significant improvements in a relatively short period of time. In order to evolve the system, changes are needed in the following areas:

- Advanced situational awareness and control.
- Increased regional collaboration aided by advanced tools to manage the operation of an increasingly dynamic system.
- Increased system flexibility.
- Multi-lateral operating agreements.²
- Some variant of regional markets that include energy, capacity, flexibility, and ancillary services.^{3, 4}
- Enhanced transmission planning that is oriented on the need to resiliently adapt to evolving supply and demand characteristics.
- Increased coordination between the BES and the distribution system.

This report provides context on the current status of the electric grid in the Western U.S. and summarizes some of the larger initiatives underway to upgrade BES planning, operations, and markets. The content is focused on activities that are or could be undertaken at a regional level to improve the reliability and economic performance of the BES while simultaneously facilitating the integration of high penetrations of clean energy resources. The document is current as of the report date. **As the industry continues its increasingly rapid evolution, ongoing updates on regional activities will be available via the America's Power Plan Website and can be accessed [here](#).**

The intended audience for the report includes policy makers and industry stakeholders who have general to advanced knowledge of electricity systems and who are interested in the current status and potential future trajectory of the electric grid in the Western US. The report takes as a given that currently enacted and future clean energy policies have and will continue to compel significantly lower utilization of fossil-fired generators,

¹ On September 8, 2011 the loss of a single transmission line in Arizona initiated a cascading electricity outage that affected parts of Arizona, Southern California, and Baja Mexico. The outage left approximately 5 million people without power for up to 12 hours. A [joint analysis](#) performed by the Federal Energy Regulatory Commission (FERC) and the North American Electric Reliability Corporation (NERC) determined that inadequate planning and deficiencies in real-time situational awareness were primary contributors to the outage.

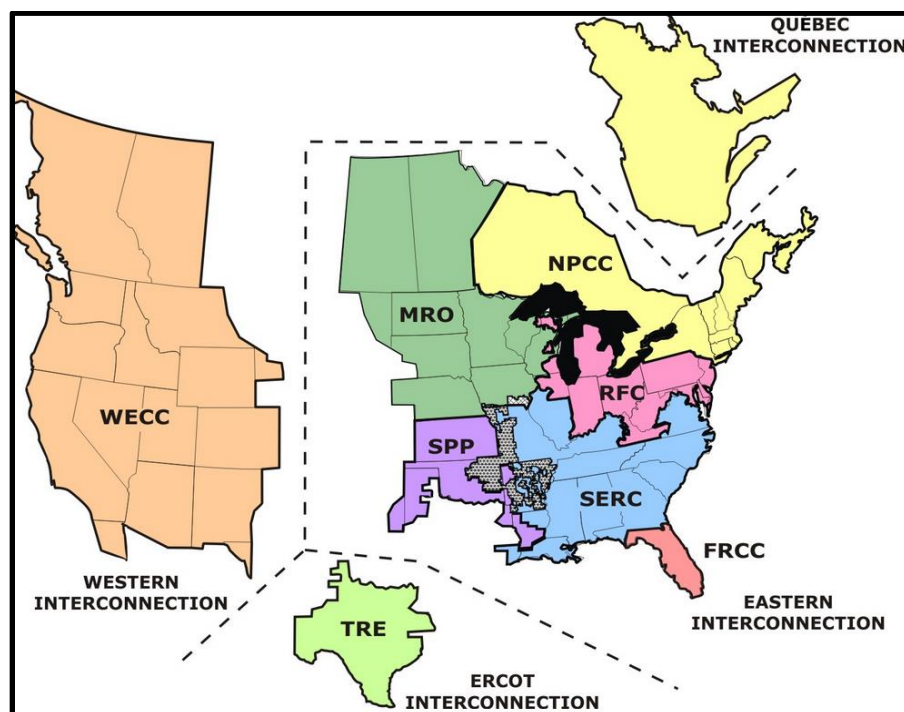
² The term multi-lateral operating agreements as used in this document refers to agreements by multiple electricity providers to pool diversity and to virtually or physically consolidate the operation of generation and transmission assets. It is explicitly recognized that entities in the Interconnection have extensive and long-standing agreements related to traditional system operations. These are not included in the scope of this report.

³ The term regional markets as used in this document refers to centralized markets that are operated and financially settled by an independent market operator and that encompass multiple utilities and balancing authorities.

⁴ Ancillary services are “Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Service Provider’s transmission system in accordance with good utility practice.” They include scheduling, system control, dispatch service, reactive supply, voltage control, regulation, frequency response, energy imbalance, and operating reserves. ([FERC Pro-Forma Open Access Transmission Tariff](#))

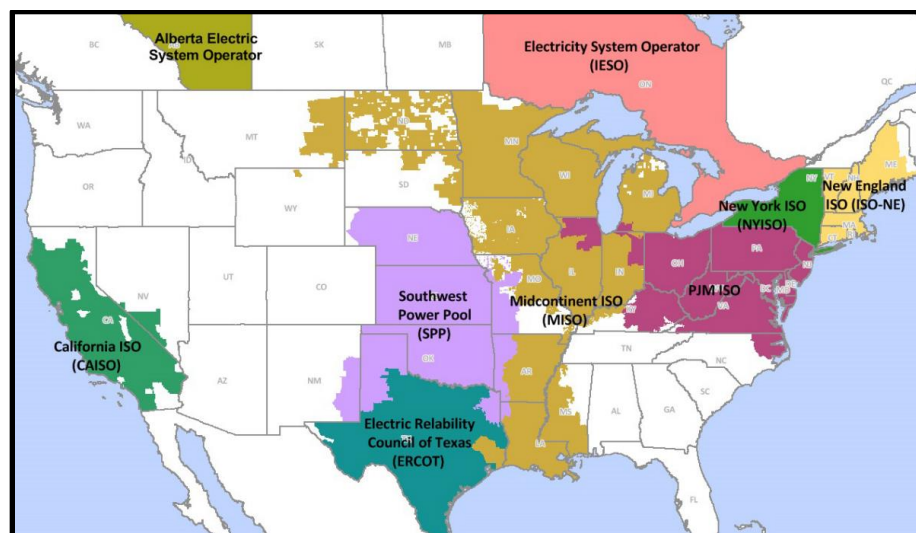
much higher deployments of renewable resources, greater efficiency, and significant increases in the interdependencies between the BES and the distribution system.⁵

Figure 1-1: North American Electric Interconnections



Source: North American Electric Reliability Corporation

Figure 1-2: U.S. Regional Transmission Organizations



Source: Federal Energy Regulatory Commission

⁵ This report is focused on the BES and on momentum in the Interconnection towards regional markets, multi-lateral operating agreements, and enhanced regional planning. It includes only tertiary coverage of the critical interface between the BES and the distribution system but explicitly acknowledges the increasingly artificial delineation between the two. The need for successful integration of the systems is a priority topic that merits its own in-depth coverage and is beyond the scope of this report.

This report is based on the precepts that:

- The challenges related to integrating clean energy resources and achieving the associated environmental and human health benefits are primarily institutional, not technical.
- Integration of clean energy resources cannot be optimized with the current bilateral markets and fragmented system operations in the West.^{6, 7}
- Increased regional collaboration, common transmission tariffs, operating reserve sharing, and some variant of regional markets that include energy, traditional capacity, flexible capacity, and ancillary services will be necessary to resolve challenges facing the Interconnection. Energy imbalance markets, multi-lateral operating agreements, and Regional Transmission Organizations RTO(s) with or without integrated forward markets should all be considered as potential options.
- Significantly more regional coordination on both transmission and generation planning will be necessary.

The development and deployment of solutions that holistically address electricity system challenges and opportunities will necessitate a regional approach and will require a high degree of collaboration between electricity providers, regulators, and a myriad of stakeholders. Because a majority of industry participants have vested interests that are entity-specific or state-specific, regional approaches that leverage broad stakeholder participation are critical.⁸

A primary and perhaps only means to align divergent stakeholder perspectives is to leverage the common goals of reliability and economic efficiency. The FERC and NERC analysis⁹ of the 2011 Southwest outage motivated substantial regional activity to improve BES reliability. In response to the outage, FERC levied approximately \$40 million in penalties¹⁰ and compelled significant post-2011 modifications to system operations. In addition to resolving specific deficiencies identified by FERC and NERC, entities in the Interconnection are taking proactive steps to upgrade the BES via a growing number of planning, operational, and market initiatives.

The following sections include an overview of foundational challenges in the West and descriptions of significant regional initiatives currently underway to resolve them. The content is intended to be a ‘lay of the land’ information resource for policy makers, regulators, and industry stakeholders who are involved with the development of strategies to maintain bulk electric system reliability, improve system efficiency, and integrate clean energy resources.

⁶ Bilateral markets as they exist in the non-ISO Western Interconnection are characterized by insufficient liquidity, poor transparency, and limited product scope. They are both inflexible and economically inefficient.

⁷ FERC identified in a [public notice](#) for a February 25th EPA Clean Power Plan Technical Conference that bilateral arrangements could have reliability implications. From the notice: *“Given that the Western region operates primarily under bilateral arrangements, what are some of the reliability considerations this may present for developing a regional compliance plan?”*

⁸ Unless otherwise specified, the term stakeholders in the context of this document refers broadly to electricity providers, policy makers, regulators, customers, developers, advocates, and special interest groups.

⁹ FERC and NERC joint report: [Arizona-Southern California Outages on September 8, 2011: Causes and Recommendations](#). April 2012.

¹⁰ Arizona Public Service Company \$3.25 million (FERC Docket No. IN14-6), Imperial Irrigation District \$12 million (FERC Docket No. IN14-7), Southern California Edison \$650,000 (FERC Docket No. IN14-8), CAISO \$6 million (FERC Docket No. ER14-10), and the Western Electricity Coordinating Council \$16 million (FERC Docket No. N14-11). The Western Area Power Administration and the FERC settled with agreements for operational modifications but without a civil penalty (FERC Docket No. IN14-9).

2. FUNDAMENTAL ISSUES: WHERE WE ARE AND HOW WE GOT HERE

As the electricity system in the Western Interconnection has developed over time, it has functioned with remarkable reliability. However, it is generally accepted that past reliability performance will not translate to the future without significant changes in system planning, operations, and markets. This section discusses the origin and nature of the unique but not intractable barriers to change in the West. The majority of the barriers are institutional, not technical, and it is useful to understand their genesis to help inform the development of solutions that address the underlying issues.

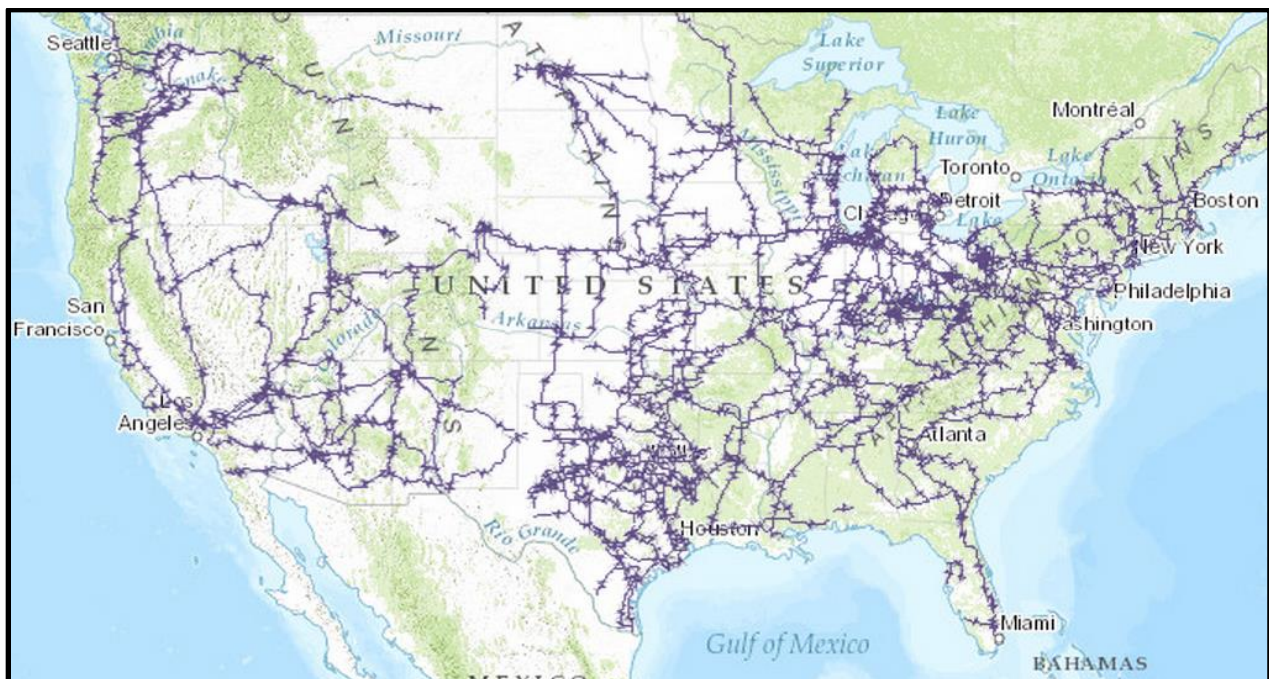
THE WEST IS DIFFERENT

Historically, infrastructure differences between the Western and Eastern Interconnections have been cited as a defense against making significant changes to the electricity system in the West. The resistance, which was rational for a discrete period of time, has been perpetuated by conflicting economic, operational, and political priorities across the Interconnection. Over time, institutional inertia has significantly influenced the planning, development, and operation of the infrastructure and has resulted in an inflexible system that is in need of fundamental upgrades.

Long Haul Transmission, Fragmented Operation, and Contract Path Transmission Tariffs

The Western BES is built around substantially more long-haul transmission than the Eastern Interconnection. This is a function of population dispersion, topography, resource choices, and the manner in which the system was built out in the early-to-mid twentieth century. Private investment was focused on concentrated load centers (i.e., the larger cities) while public investment, initially shaped by the 1920 Federal Water Power Act and the 1936 Rural Electrification Act, was focused on providing electricity to geographically dispersed populations. While very effective at developing electricity infrastructure across the West, the investment dynamics inadvertently created a system with highly fragmented ownership and operations.

Figure 2-1: U.S. Transmission Map (345 kV and Larger)



Source: [EIA Mapping Interactive Tool](#)

One manifestation of the balkanization can be seen in the proliferation of Balancing Authorities (BAs) in the West.¹¹ The reliable operation of the Interconnection is currently managed by 38 separate BAs. Each operates essentially as an island with the incumbent obligation to balance supply and demand in real time primarily using resources within the boundaries of its control area. This is becoming a focus for increased scrutiny because pooling of demand and supply variability across broad geographical footprints is indisputably a more optimal approach for system reliability, energy economics, and clean energy resource integration.

As the transmission infrastructure was built out in the 20th century, contract-path transmission products were developed and are still the basis of the majority of the transmission transactions in the non-ISO West. Because electricity flows according to physics and not contracts, the contract-path methodology creates unscheduled power flows and can cause reliability, equity, and institutional issues. As one example,¹² transmission congestion between the Pacific Northwest and California can force the redirect of the physical flow of electricity off of the Northwest-to-California transmission contract path and into Wyoming, Colorado, and New Mexico. Transmission operators along the Front Range respond to the unexpected loading on their systems with operational strategies such as adjusting their generation, cutting transmission schedules in their footprints, and deploying phase shifters.¹³ This can create reliability challenges because system operators along the Front Range do not have visibility or control over the cause of the unscheduled flows. It creates equity issues because the affected transmission and generation owners are not compensated for the unscheduled use of their assets. The combination of the reliability and equity impacts understandably creates institutional friction.

Contract-path transmission is also problematic for renewable resource economics. When renewable energy is sold over long distances from resource rich areas to major load centers, the energy may be transferred across multiple transmission systems and is assessed charges for each segment of the contract-path. Referred to as wheeling charges, these tolls are standard in the non-ISO West but nonexistent in the Eastern Interconnection RTOs. Accrual of multiple wheeling charges on a contract path is referred to as pancaking. Pancaking distorts renewable energy economics and can result in sub-optimal utilization of high quality low cost resources.

The RTO regions of the U.S. transitioned to flow-based transmission tariffs many years ago and those regions manage the physical and financial aspects of the system congruently. It is becoming increasingly accepted that a flow-based paradigm will be necessary in the non-ISO West in the relatively near future to resolve the fundamental reliability and economic challenges created by contract-path approaches.



Resolution of challenges created by fragmented system ownership and operations will require modifications to transmission access, tariffs, operational practices, and cost recovery.

Coal Plants, Insufficient Flexibility, and Essential Reliability Services

The long-haul transmission system backbone in the West was, for performance and reliability reasons, engineered and constructed around large coal-fired generating units. Because coal plants are designed to operate with consistent and high capacity factors, do not ramp up or down quickly, have high operating minimums, and have long lead times for startup, the reliance on these units makes the system inherently inflexible. This was fine from an operational – although not environmental – perspective when the balance of the system was relatively static. But, these operating characteristics are a liability in a system that has significant variable generation and dynamic

¹¹ A Balancing Authority (BA) is “The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.” Source: [North American Electric Reliability Corporation Glossary of Terms](#). A map of the Western Interconnection Balancing Authorities is provided in Appendix A.

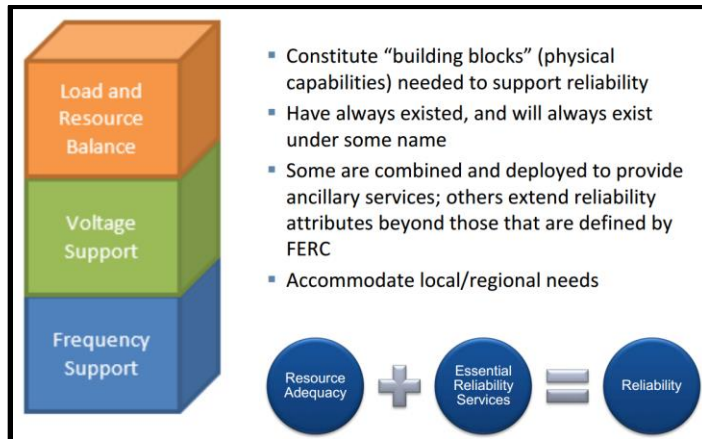
¹² This example is illustrative. Unscheduled flows originate from many areas of the Interconnection during both normal and contingency operations.

¹³ Phase shifters create impedance on a transmission line which can act as a surrogate for transmission congestion and effectively ‘push back’ on unscheduled flows.

net consumer demand. As a result, resource flexibility has become a crux issue for electricity providers and regulators.¹⁴

From a reliability perspective, large coal-fired generating units currently provide a significant percentage of the system voltage control, reactive power, inertia, frequency response, and regulation. These functions are fundamental for reliability and will need to be provided by other resources as the coal-fired units are retired.¹⁵

Figure 2-2: NERC Essential Reliability Services



Source: [NERC ERSTF April 2014 Presentation](#)

When appropriately configured with commercially available equipment, many technologies other than coal generators are fully capable of providing reliability services and can do so in a more precise manner than older coal or natural gas units that do not respond well to automated signals. Today, active power controls on wind turbines, advanced solar inverters, flexible natural gas-fired generators, and capacitor banks are capable of performing reliability services that are currently provided by coal generators. Additionally, system operators can enhance reliability with operational changes such as putting additional equipment on automatic generation control and changing equipment settings to enable technical potential in the existing fleet. In the near future solar resources, distributed generation, demand response, and storage will become essential components in a system that leverages the broad capabilities of a diverse set of resources.

Although technical potential exists to support system reliability with a portfolio of resources, market mechanisms in the West are currently insufficient to create economic incentives to encourage asset owners to enable the technical potential of existing equipment and to invest in commercially available but under-utilized clean energy technologies. The deficiencies in economic incentives are due to lack of liquid markets that encompass broad geographic footprints and that appropriately monetize the value of system flexibility and essential reliability services.¹⁶

¹⁴ Hour to hour consumer demand has changed dramatically over the past 25 years and is expected to continue to shift in ways that are not yet fully quantified by the industry. These changes include (1) increasing use of electronics within the home; (2) increasing penetration of air conditioning as consumer expectations and weather patterns change; (3) increasing electricity demand from very large centralized computing systems (e.g., Google servers); (4) increasing domestic oil and gas production; (5) expatriation of domestic manufacturing; (6) increasing opportunities for consumers to self-generate electricity; and (7) increasing deployment of technologies such as rooftop solar PV, electric vehicles, distributed energy storage, and demand response. Although energy efficiency advancements are expected to offset significant load growth, energy efficiency doesn't typically address variability of demand from minute-to-minute, over an hour, in the course of a day, or between seasons. It is this variability that system operators will need to understand and respond to in ways that have not been typical in the past.

¹⁵ For additional information, please see the NERC Essential Reliability Services Task Force (ERSTF) October 2014 [Concept Paper on Essential Reliability Services that Characterize Bulk Power System Reliability](#).

¹⁶ There are six essential reliability services: operating reserve, frequency response, ramping capability, active power control, reactive power/voltage control, and disturbance ride-through tolerance. Source: [NERC ERSTF April 2014 Presentation](#)



To ensure system flexibility and reliability, price signals will be necessary to motivate asset owners to (1) enable technical potential in the existing system and (2) invest in new technologies.

Bilateral Markets, Hourly Operations, and Manual Dispatch

Entities in the non-ISO¹⁷ areas of the Western Interconnection currently transact the bulk of their business bilaterally as opposed to through centralized markets and much of the system in the West is still operated on an hourly basis using manual processes. As the characteristics of the electricity system including demand profiles, generation resources, and the configuration of the transmission system have evolved over time, the bilateral manual approach has degraded in efficiency and is becoming an increasing barrier to the reliable and economic operation of the system. Inefficiency, poor liquidity, and lack of transparency are hallmarks of this legacy structure.

Bilateral markets are slow, do not optimize the use of existing infrastructure, and do not necessarily support appropriate infrastructure investments. Hourly operations are economically inefficient and can cause reliability issues.¹⁸ Additionally, integration of variable energy resources is challenged by hourly operations because variable resources inherently increase and decrease production in sub-hourly timeframes. The resources that are used to resolve energy imbalances are typically constrained to generators within the balancing authority area and, although the units used are typically flexible from an operational perspective, they are not necessarily the most efficient or environmentally benign units in the regional generating fleet. Although an increasing number of electricity providers are moving towards automated sub-hourly operations, manual practices are still ubiquitous in the West. This can be a reliability issue, is generally uneconomic, and creates challenges for clean energy integration

By contrast, the California Independent System Operator (CAISO), the Alberta Electric System Operator, and a majority of the entities in the Eastern Interconnection have centralized markets and operations that are co-optimized to transact, schedule and dispatch energy, capacity, and a host of ancillary services that support the efficient and reliable operation of the grid. These regions transitioned to centralized sub-hourly operations and markets years ago to protect system reliability and optimize efficiency.



Although some entities in the West are averse to centralized markets and operations,¹⁹ some degree of real or virtual consolidation of both is necessary and inevitable.

Resolution of the Fundamental Issues in the West

The fundamental issues in the West are primarily institutional, not technical. While resolving these challenges is a formidable task, the benefits are substantial. Financial and safety risks related to outages, inefficiency costs to consumers, and an inability to optimally integrate clean energy resources and achieve the associated environmental benefits will be an inevitable outcome of the legacy system in the West unless there are both institutional and physical changes made. In order to develop a BES that is sufficiently resilient to adapt to a dynamic future, there will need to be an evolution of the manner in which the system is planned and operated and the means by which entities are compensated for the energy, power, ancillary services, and emissions reductions they provide.

¹⁷ There are two ISOs in the Western Interconnection: The CAISO and the Alberta Independent System Operator.

¹⁸ Although FERC Order 764 regarding the integration of variable generation requires transmission operators to offer 15-minute transmission scheduling to entities that request it, the Order does not require that the entire system be scheduled or dispatched on an intra-hourly basis.

¹⁹ The aversion to centralized operations and markets is due to a myriad of institutional factors and can be roughly grouped into four categories: (1) Deep distrust of markets due to the California electricity crisis of 2000 and 2001; (2) Regional resistance, particularly by non-jurisdictional electricity providers, to expansions of FERC jurisdiction; (3) Reluctance by state regulators to accede to FERC jurisdiction on matters they see as part of the state domain; and (4) Concerns about the ability of a centralized market operator to reliably manage the fragmented system. The arguments against centralization are being increasingly overcome by reliability and economic equity considerations.

3. BULK ELECTRIC SYSTEM ACTIVITIES IN THE WESTERN INTERCONNECTION

The challenges that impede the deployment of an optimized fleet of resources that reliably meets environmental objectives at least cost is primarily institutional. While some technical improvements can and are being made, the big opportunities are in regional collaboration. Enacted policies including renewable energy subsidies and mandates have laid the foundation for the development and maturation of clean energy technologies. As a result of these policies, the technical ability of the resources to deliver clean, reliable, and economic power has increased dramatically.

More fully coordinated regional planning and operations along with geographically broad regional markets will be necessary to optimally leverage the technical potential of clean energy resources and to transition the system to a one with:

- Enhanced operational performance supported by 21st century information technology.
- Market-based structures that motivate and enable investors to offer an expanding suite of products and services.
- Enhanced system planning and tighter connections between generation and transmission development.
- Significantly improved linkages between the BES and the distribution system.
- Monetization of the environmental attributes of clean energy technologies.
- Movement away from subsidies for all generation technologies.

In order to reach these objectives, substantial changes will be necessary to resolve existing institutional barriers. As a result of the extensive work of industry stakeholders, there are a growing number of regional planning, operational, and market initiatives underway in the West. Particularly significant entities and activities include:

1. Market and Operating Initiatives
 - CAISO Energy Imbalance Market (EIM)
 - PacifiCorp Full Participation in the CAISO
 - Northwest Power Pool Market Assessment and Coordination Committee (NWPP MC)
 - Southwest Variable Energy Resources Initiative (SVERI)
 - Mountain West Network Tariff
 - The Integrated Transmission System Tariff and the Western Area Power Administration's Participation in the Southwest Power Pool
2. FERC Order 1000 Transmission Planning and Cost Allocation
3. Power Marketing Administrations and Other Non-Jurisdictional Electricity Providers
4. EPA Clean Power Plan
5. Peak Reliability Coordinator
 - Board of Directors and Member Advisory Committee
 - Enhanced Curtailment Calculator (ECC)
 - Western Interconnection Synchrophasor Program (WISP)
6. Western Electricity Coordinating Council (WECC)
 - Board of Directors and Member Advisory Committee
 - WECC Transmission Planning and System Assessment Committees, Task Forces, and Working Groups
 - WECC System Flexibility Assessment
7. Department of Energy

Activities underway in the Interconnection will shape the direction of the industry for the next 50 years and are critically important to develop a solid foundation for future progress. This section includes an overview of initiatives that are currently underway and/or that could be considered at a regional level to improve the reliability and economic performance of the BES while simultaneously facilitating the successful integration of increasing penetrations of wind, solar, and other clean energy resources.

The following sections are current as of the date of this document. **As the industry continues its increasingly rapid evolution, ongoing updates on regional activities will be available via the America's Power Plan Website and can be accessed [here](#).**

3.1 MARKET AND OPERATING INITIATIVES

Multi-lateral operating agreements²⁰ and markets²¹ in the non-ISO portion of the Western Interconnection have been largely nascent until this decade. Regional reliability is currently managed by 38 separate Balancing Authorities (BAs) with the obligation to perform a portfolio of reliability functions including the real time balancing of supply and demand. The majority of transmission operations are contract-path versus flow-based and most electricity transactions are bilateral. Products beyond energy and capacity are poorly developed. These characteristics developed over time as the result of a variety of factors but are becoming increasingly untenable. A future that includes high penetrations of clean energy resources and lower levels of fossil generation will benefit greatly from more holistically coordinated planning and operations along with liquid markets for energy, traditional capacity, flexible capacity, energy imbalance, ancillary services, and reliability services. Centralized markets have the potential to incentivize owners of clean energy assets to invest in equipment such as flexible generating units, capacitor banks, active power controls on wind turbines, advanced inverters, storage, and demand response to competitively provide products and services that have traditionally been the domain of the incumbent utilities' thermal generating fleets.

Regional markets and multi-lateral operating agreements are necessary to transition the system to one that is synergistically more reliable and more economic than the existing fragmented bilateral paradigm. This is because:

- A large geographic footprint allows system operators to net the variability of renewable generation, traditional generation, and consumer demand. This yields reliability and economic benefits by reducing the need for system operators to adjust thermal generation and curtail renewable generation in real time to balance the system; which reduces both the amount of reserves that need to be held²² and thermal generation cycling costs.
- System operators with access to large pools of generation and transmission resources are able to more effectively dispatch the system in sequence of lowest cost first which has the potential to reduce system-wide marginal operating costs and transmission congestion.
- Access to a large and geographically diverse set of generation and transmission resources fundamentally improves the reliability of the system. Reserve Sharing Groups are an empirical example of the reliability benefits of coordinated operations. Reserve Sharing Group members have for many years engaged in multi-lateral agreements to provide generation and transmission resources to neighboring entities during unexpected equipment outages.²³

²⁰ The term multi-lateral operating agreements as used in this document refers to agreements by multiple electricity providers to pool diversity and to virtually or physically consolidate the operation of generation and transmission assets. It is explicitly noted that entities in the Interconnection have extensive and long-standing agreements related to traditional system operations. These are not included in the scope of this report.

²¹ The term regional markets as used in this document refers to centralized markets that are operated and financially settled by an independent market operator and that encompass multiple utilities and balancing authorities.

²² Reserves are generation capacity set-asides. There are three primary types: Traditional operating reserves respond to deviations in supply and demand that occur in the normal course of operations, contingency reserves protect system reliability by responding to unexpected outages of generation or transmission resources, and flexibility reserves are designed for wind and solar ramps. Operating and contingency reserves are required by NERC standards. Flexibility reserves are not required by NERC but are held by BAs to ensure that system operators have access to sufficient dispatchable flexible resources in order to maintain reliability. Reserves can be reduced in a system with coordinated markets and operations because system operators who have better situational awareness and access to more resources in real time do not require the same level of idle capacity as operators with smaller pools of available resources.

²³ Reserve Sharing Groups are NERC-registered reliability entities that are based on multi-lateral agreements between neighboring electricity providers to provide mutual assistance in contingency situations. There are three in the Western Interconnection: The [Southwest Reserve Sharing Group](#), the [Rocky Mountain Reserve Sharing Group](#), and the [Northwest Power Pool Reserve Sharing Group](#). The groups cover outages of transmission facilities, thermal generating units, and hydro generating units. They do not include coverage for expected or unexpected declines in renewable generation.

Research supports that the BES is technically capable of integrating renewable resources²⁴ without markets and regional operating agreements, but research also demonstrates that markets including but not limited to an EIM can dramatically improve the economics of system operations with and without renewables.^{25, 26, 27} Additionally, markets and multi-lateral operating agreements have the potential to supplant infrastructure investments and should be prioritized when evaluating resource sufficiency and options to meet system performance requirements.²⁸

There are multiple potential pathways forward for regional collaboration, and there won't be a one size fits all solution. It is suggested that policy makers consider a portfolio of strategies that encompass market-based and/or operations-focused approaches.

3.1.1 CAISO Energy Imbalance Market (EIM)

In April of 2010 the WECC Board, at the urging of the Western Interstate Energy Board and other regional stakeholders, voted to evaluate the costs and benefits of a regional Energy Imbalance Market (EIM).²⁹ This decision was a pivotal step towards the development of the CAISO EIM, the NWPP MC, and other regional initiatives.

The purpose of an EIM is to resolve differences between scheduled and actual generation and demand, referred to as energy imbalance, in five minute increments using the least cost resources while respecting the constraints of the generating units and the transmission system. In an EIM, the market operator pools the generation and load of participating entities thereby netting system variability and leveraging the operational and economic capabilities of the consolidated fleet. Energy transactions are cleared at market prices based on the marginal cost of generation and transmission congestion costs.

This is in contrast to the bilateral energy imbalance management that is currently in place in the non-ISO portions of the Interconnection. Under the bilateral paradigm, the system is dispatched in one hour increments and each BA manages intra-hour imbalances within its footprint using generation it controls. The BA then charges the sources of the energy imbalance at static FERC-approved rates.

²⁴ Examples of research validating the feasibility of integrating renewable resources in the Western Interconnection are available via the [National Renewable Energy Laboratory Western Wind and Solar Integration Study \(WWSIS\)](#), the [California Low Carbon Grid Study](#), and the NERC-CAISO November 2013 report [Maintaining Bulk Power System Reliability While Integrating Renewables: The CAISO Approach](#).

²⁵ Milligan, M.; Clark, K.; King, J.; Kirby, B.; Guo, T.; Liu, G. [Examination of Potential Benefits of an Energy Imbalance Market in the Western Interconnection](#), National Renewable Energy Laboratory Report No. TP-5500-57115. March 2013.

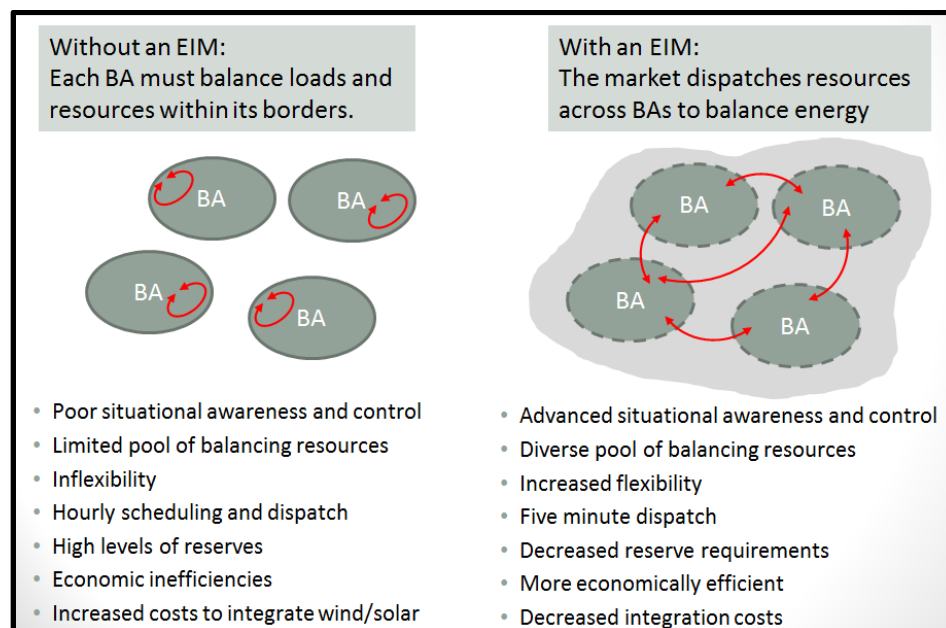
²⁶ Samaan, et al. [Analysis of Benefits of an Energy Imbalance Market in the NWPP](#), Pacific Northwest National Laboratory Report No. 22877. October 2013.

²⁷ E3 Consulting. EIM benefits reports: [CAISO-PacifiCorp \(March 2013\)](#), [CAISO-NV Energy \(March 2014\)](#), [CAISO-Puget Sound Energy \(September 2014\)](#), and [CAISO-Arizona Public Service Company \(April 2015\)](#).

²⁸ Resolution of challenges facing the Interconnection will require expanded access to energy, traditional capacity, flexible capacity, and ancillary services. An EIM addresses the real-time energy portion of the equation, but fully integrated markets will eventually be necessary to appropriately monetize and compensate for the benefits of a range of essential system reliability services provided by traditional infrastructure and non-traditional clean energy alternatives. The existing bilateral markets do this poorly, if at all. Please see Section 2 for discussion of these topics.

²⁹ There was significant work done prior to the WECC decision, but the April 2010 vote was pivotal. The WECC analysis was originally focused broadly on what was then referred to as the Efficient Dispatch Toolkit (EDT). The EDT included two elements: An EIM and an Enhanced Curtailment Calculator (ECC). Over time, stakeholder engagement regarding the two mechanisms has diverged into separate discussions. The EIM is primarily approached as a market mechanism, although it is wholly dependent upon technical capabilities. The ECC work is currently in the domain of a highly technical stakeholder group, but it (or something like it) will be essential over the long term.

Figure 3-1: Business as Usual Compared to an EIM



Source: Xcel Energy

In March of 2013 the CAISO and PacifiCorp entered into a Memorandum of Understanding to explore the feasibility of developing an EIM under which the CAISO would be the market operator and PacifiCorp would be a participant. The CAISO EIM market characteristics were developed in a way that is responsive to the requirements of the participants, and the CAISO EIM is unique relative to other markets. Important design elements that were established during the development of the EIM include:

- Market governance (currently under further development).
- Market monitoring.
- The roles and responsibilities of the various types of participants.
- The amount of transmission capacity that is allocated to the market and at what priority level.
- Time intervals and requirements for scheduling, bidding, and dispatch.
- The method for calculating energy prices.
- Transaction settlement processes.

The CAISO EIM was formally announced in March of 2013 and is an extension of the CAISO real time energy market to additional service territories within the Interconnection. After extensive stakeholder engagement and regulatory activity, the CAISO-PacifiCorp EIM began binding operations on November 1, 2014. NV Energy is expected to join the market in October of 2015.³⁰ Puget Sound Energy and Arizona Public Service both announced in early 2015 that they intend to join the CAISO EIM in October of 2016.

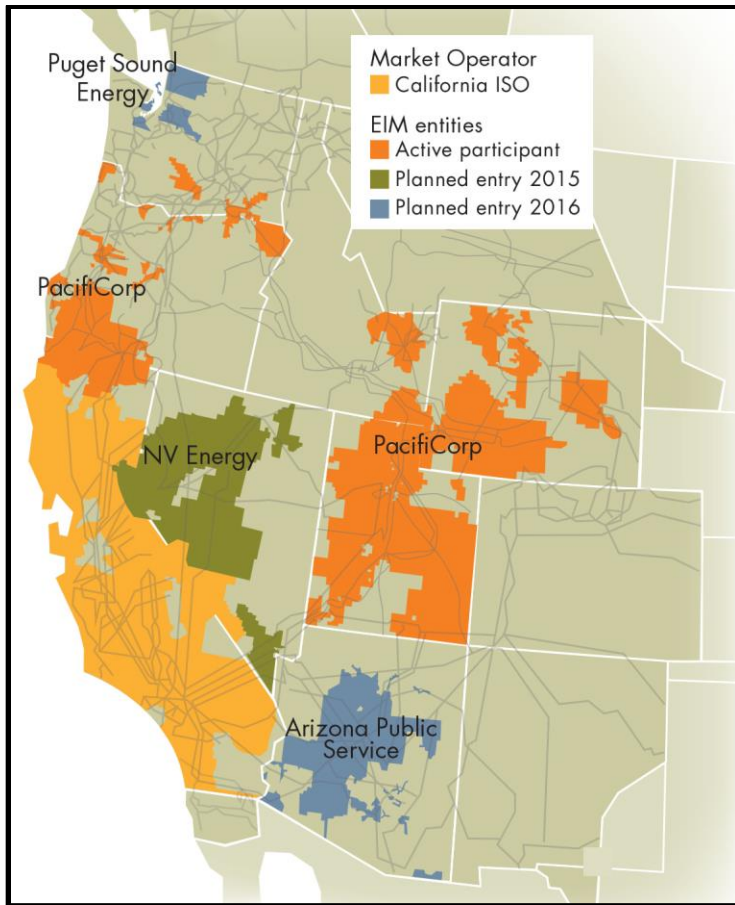
Table 3-1: CAISO EIM Chronology

Date	Description
Apr 2010	WECC approved the development of a benefit cost analysis for the Efficient Dispatch Toolkit (EDT); which included an EIM and an Enhanced Curtailment Calculator (ECC).
Oct 2011	WECC released the <u>WECC Efficient Dispatch Toolkit Cost-Benefit Analysis</u> .
Late 2011	The <u>PUC EIM Group</u> , facilitated by WIEB, was formed.
May 2012	National Renewable Energy Laboratory released an analysis of <u>Operating Reserve Reductions From a</u>

³⁰ NV Energy was acquired in December of 2013 by Berkshire Hathaway Energy, which also owns PacifiCorp.

	Proposed Energy Imbalance Market With Wind and Solar Generation in the Western Interconnection for the full Western Interconnection footprint.
Feb 2013	FERC released a <u>Qualitative Assessment of Potential Reliability Benefits from a Western Energy Imbalance Market</u> .
Mar 2013	National Renewable Energy Laboratory released a BA-level <u>Examination of Potential Benefits of an Energy Imbalance Market in the Western Interconnection</u> .
Mar 2013	CAISO and PacifiCorp released a <u>Memorandum of Understanding</u> regarding the development of an EIM.
Mar 2013	The <u>PacifiCorp-ISO Energy Imbalance Market Benefits</u> report was released.
Apr 2013	CAISO submitted an <u>Implementation Agreement for the CAISO-PacifiCorp EIM</u> to FERC.
Jun 2013	FERC <u>approved</u> the CAISO-PacifiCorp EIM Implementation Agreement. (Docket No. ER13-1372)
Feb 2014	CAISO filed <u>EIM tariff revisions</u> with FERC. The original filings were followed by many interventions, compliance filings, and interim decisions. (Docket No. ER14-1386)
Feb 2014	BPA and PacifiCorp entered into a non-binding <u>Memorandum of Understanding</u> regarding the coordination and facilitation of PacifiCorp's participation in the CAISO EIM.
Mar 2014	PacifiCorp filed <u>EIM tariff revisions</u> with FERC. The original filings were followed by many interventions, compliance filings, and interim decisions. (Docket Nos. ER14-1578 and ER14-2544)
Mar 2014	The <u>NV Energy-ISO Energy Imbalance Market Economic Assessment</u> was released.
Apr 2014	CAISO submitted an <u>Implementation Agreement for the CAISO-NV Energy EIM</u> to FERC.
Apr 2014	NV Energy filed with FERC for approval to participate in the CAISO EIM with the Nevada PUC. (<u>Docket No. 14-04024</u>)
Jun 2014	FERC <u>approved</u> the CAISO-NV Energy Implementation Agreement (ER14-1729).
Aug 2014	The Nevada PUC <u>granted</u> NV Energy's application to participated in the CAISO EIM. (<u>Docket No. 14-04024</u>)
Oct 1, 2014	The CAISO and PacifiCorp EIM began parallel operation simulations.
Oct 20, 2014	FERC issued orders approving, with qualifications, the <u>CAISO EIM tariff revisions</u> and the <u>PacifiCorp EIM tariff revisions</u> .
Nov 1, 2014	The CAISO EIM and PacifiCorp EIM went live with binding operations. NV Energy is planned to go live in October of 2015.
Feb 11, 2015	The CAISO released its first <u>Benefits for Participating in EIM</u> .
Mar 15, 2015	Puget Sound Energy <u>announced</u> that it will participate with the CAISO EIM effective October 1, 2016 and released the <u>Benefits Analysis of Puget Sound Energy's Participation in the ISO Energy Imbalance Market</u> .
Mar 20, 2015	CAISO submitted an <u>Implementation Agreement for the CAISO-Puget Sound Energy EIM</u> to FERC. (Docket No. ER15-1347)
Apr 17, 2015	Arizona Public Service filed an <u>EIM benefits analysis</u> with the Arizona Corporation Commission. The filing did not identify a specific date for the entity to join the CAISO EIM and it did not explicitly request commission approval.
May 18, 2015	The CAISO and Arizona Public Service <u>announced</u> that the entities have entered into an agreement for APS to begin participating in the EIM in October of 2016.
Ongoing	Updates are available on the <u>CAISO EIM webpages</u> , the <u>PacifiCorp EIM webpages</u> , and the <u>NV Energy Open Access Same-time Information System (OASIS)</u> , and the <u>Puget Sound Energy EIM webpages</u> . As of the date of this document, APS had not yet developed a communication forum for its EIM activities.

Figure 3-2: CAISO EIM Footprint



Source: CAISO

Benefits Analyses

The potential benefits of the CAISO EIM for the CAISO, PacifiCorp, NV Energy, Puget Sound Energy, and Arizona Public Service have been evaluated in four separate studies. The following summary table is a compilation of results provided in the March 2013 CAISO-PacifiCorp, March 2014 CAISO-NV Energy, September 2014 CAISO-Puget Sound Energy, and April 2015 CAISO-Arizona Public Service Company EIM benefits reports.

To caveat, it is important to note that the results shown are the projected benefits for each individual entity. There are also projected incremental benefits for existing participants as new entities join the market, but those benefits are not represented in the table because they were not provided in the public reports. Additionally, the analyses were prepared separately over a two year period and include differences in assumptions and study years. Therefore, the results are not completely comparable but are assumed to be sufficiently so for this summary.

Table 3-2: Summary of EIM Benefits Reports (in millions of dollars)

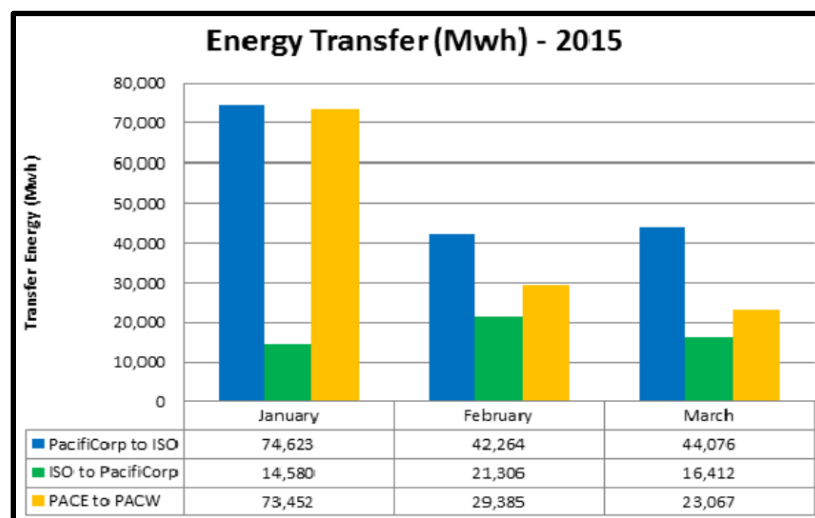
Entity Report Date Study Year Range	CAISO Mar-13 2017		PAC Mar-13 2017		NVE Mar-14 2017		PSE Sep-14 2020		APS Apr-15 2020	
	Low High		Low High		Low High		Low High		Low High	
Intra & Inter-Regional Dispatch, Sub-hourly Dispatch	11.2	8.9	13.5	31.9	3.1	4.7	16.7	18.5	5.9	14.9
Reduced Flexibility Reserves	7.8		3.2	14.9	2.8	3.6	1.6	1.6	1.0	3.2
Reduced VER Integration Costs		36.4					9.1	9.1		
Reduced VER Curtailments	1.1	10.8			0.1	1.2	0.8	0.8		
Total Benefits	20.1	56.1	16.7	46.8	6.0	9.5	28.2	30.0	6.9	18.1

Sources: [March 2013 CAISO-PacifiCorp](#), [March 2014 CAISO-NV Energy](#), [September 2014 CAISO-Puget Sound Energy](#), and [April 2015 CAISO-Arizona Public Service Company](#) EIM benefits reports.

Evaluation of EIM Actual Benefits

On April 30³¹, 2015, the CAISO released the first full quarter evaluation of the actual EIM benefits. The results are reported to be in line with what was estimated in the pre-launch benefits analyses.

Table 3-3: CAISO EIM Energy Transfers January through March 2015 (in megawatt-hours)



Source: [CAISO EIM Benefits Presentation](#). April 2015.

Table 3-4: Estimated EIM Benefits – January through March 2015 (in millions of dollars)

BAA	January	February	March	Total
ISO	\$0.48	\$0.49	\$0.48	\$1.44
PACE	\$0.88	\$0.83	\$0.91	\$2.63
PACW	\$0.42	\$0.49	\$0.28	\$1.19
Total	\$1.78	\$1.81	\$1.67	\$5.26

Source: [CAISO EIM Benefits Presentation](#). April 2015.

³¹ [CAISO Briefing on Energy Imbalance Market - Update on EIM Operations](#). April 30, 2015.

CAISO-PacifiCorp EIM Tariff Challenges

The November 1st launch of the EIM was historic and represents an enormous accomplishment for the entities and individuals involved. As was reasonable to expect in an undertaking of this magnitude, there were a limited number of issues with the new operational paradigm and market. While many of the issues have been or are being addressed, there are ongoing challenges related to price spikes that the CAISO and PacifiCorp are working with FERC to resolve.

Shortly after the market launch, unexpected price excursions began to reach the \$1,000/MWh CAISO market cap. In a November 13th filing to FERC, the CAISO requested a 90-day waiver of certain provisions of its tariff,³² stating that it *“has determined that system conditions, operations processes, the current level of EIM participating resources, and the new operating environment are complicating the timing of, and restricting the amount of, effective economic bids necessary to relieve the constraints”* which is creating high clearing prices for some transactions.³³

In its request to FERC, the CAISO explained that the objective of the waiver would be to stabilize EIM clearing prices *“while additional tools are implemented to improve the visibility of the market system and results, further automated and manual process changes are established, and the amount of timely resource capability and flexibility are increased in the Energy Imbalance Market.”*³⁴ FERC granted this request.³⁵

The CAISO subsequently filed a request for an extension of the partial tariff waiver for a twelve-month transition period for PacifiCorp and as new EIM entities (e.g., NV Energy) join the market.³⁶ Regional stakeholders who were supportive of the 90-day waiver period objected to the requested 12-month waiver request.³⁷ On March 16th, FERC rejected the request for a 12-month waiver period, stating that *“we find that the existing EIM provisions in CAISO’s tariff related to the imbalance energy price spikes in PacifiCorp’s BAAs are unjust and unreasonable.”*

In its March 16th Order, FERC initiated *“an investigation under Section 206 of the Federal Power Act in Docket No. EL15-53-000 to develop a record upon which the Commission may address issues related to the imbalance energy price spikes in PacifiCorp’s BAAs.”*³⁸ The Commission further ordered that the CAISO *“revise the EIM provisions in its tariff to include requirements to ensure readiness prior to new EIM Entities commencing EIM operations. Such revisions should include: (1) a robust market simulation and appropriate period of parallel operation to ensure that new entities joining the EIM have adequate opportunity to identify and resolve operational issues prior to full activation; and (2) a requirement that CAISO and the new entrant each submit a market readiness certificate at least 30 days prior to full activation in the EIM, certifying the readiness of the new EIM Entity’s processes and systems.”*³⁹

³² Each FERC-jurisdictional transmission services provider is required to file an Open Access Transmission Tariff (OATT) with the FERC detailing its terms of service.

³³ [FERC Order Granting Tariff Waiver and Directing Informational Filings](#). December 1, 2014. FERC Docket ER15-402.

³⁴ [CAISO Petition for Limited Tariff Waiver and Request for Expedited Consideration](#). November 13, 2014. FERC Docket No. ER15-402.

³⁵ [FERC Order Granting Tariff Waiver and Directing Informational Filings](#). December 1, 2014. FERC Docket ER15-402.

³⁶ [CAISO request for tariff amendment to implement transition period pricing for the energy imbalance market](#). January 15, 2015. FERC Docket No. ER15-861.

³⁷ FERC Docket No. ER15-861 intervention filings.

³⁸ Per Section 206 of the Federal Power Act, *“FERC, either pursuant to a complaint or on its own, (1) may find that an existing rate, term or condition is not just and reasonable or is unduly discriminatory or preferential, and (2) specify a new rate, term or condition that is just and reasonable and not unduly discriminatory or preferential and that is to be thereafter used.”* ([FERC 101](#)). Per a PJM summary: *“The rates, terms and conditions are required to be just and reasonable and not unduly discriminatory or preferential; otherwise, they are deemed unlawful. This is generally referred to as the “just and reasonable” standard. Sections 205 and 206 establish the standards for demonstrating why a proposed revision to a governing document should be approved by the FERC.”*

³⁹ [Order rejecting proposed tariff revisions, instituting a Section 206 proceeding, granting extension of waiver and directing compliance filing and informational report](#). March 16, 2015. FERC Docket EL15-53.

Since the March 16th order, 29 entities have filed for intervention and multiple iterations of protests and reply comments have been filed. On April 15th FERC issued an order granting rehearing. Additional action on the docket is pending.

EIM Long-Term Governance^{40, 41}

The independence of the EIM governance from the California Governor-appointed CAISO Board is critically important for a number of entities outside of California and will be necessary for the optimal expansion of the EIM to additional states. Although the EIM is currently under the purview of the CAISO Board, a key task is to develop an alternate long term governance structure.⁴² To this end, during the development of the EIM an EIM Transitional Committee was appointed to advise the CAISO Board on both the governance and the implementation of the market.⁴³ The Transitional Committee is in the process of iterating a straw proposal with stakeholders. The schedule is provided in the following table.

Table 3-5: CAISO EIM Transitional Committee Schedule

Date	Event
Jan-15	Issue Paper posted
Jan-15	Stakeholder meeting on Issue Paper
Jan-15	Stakeholder comments due
Mar-15	Straw Proposal Posted
Mar-15	Stakeholder meeting on Straw Proposal
Apr-15	Stakeholder comments due
Apr-15	Committee meeting (Folsom, CA)
May-15	Committee to post revised or final Straw Proposal
May-15	Stakeholder meeting on revised or final Straw Proposal
Jun-15	Stakeholder comments due
Aug-15	Committee to post draft governance proposal

Year 1 Enhancements

The CAISO has launched a “Year 1 Enhancements” process and is iterating proposals between stakeholders and the CAISO Board. The Year 1 Enhancements concept was included in the initial development of the market design, recognizing that there would be some topics that would inevitably need more attention after the market launched. The Year 1 Enhancements under consideration include mechanisms to accommodate participating entities’ preferences about whether or not to provide imbalance energy into California if to do so would trigger greenhouse gas compliance obligations, modifications to the settlement processes for non-participating resources, and transmission access for EIM transfers between BAs.⁴⁴

3.1.2 PacifiCorp Full Participation in the CAISO

On April 14, 2015 the CAISO and PacifiCorp announced that the entities had entered into a Memorandum of Understanding to explore full PacifiCorp participation in the CAISO markets with a target implementation date in 2017.⁴⁵ With this transition, the CAISO would operate the generation and transmission resources in the combined footprint and function as a centralized market operator. This move was expected at some point in the future, but the announcement less than six months after the launch of the CAISO EIM was a surprise to some stakeholders. Although there has not been any public discussion, it seems possible that Berkshire Hathaway, the parent company for both PacifiCorp and NV Energy, is formally evaluating a range of options for NV Energy also.

⁴⁰ EIM Transitional Committee information, including a member list, is available [here](#).

⁴¹ Documents related to the governance are available [here](#) and updates to the Transitional Committee Schedule are available [here](#).

⁴² EIM Transitional Committee. [Issue Paper: Conceptual Models for Governing the Energy Imbalance Market](#). January 5, 2014.

⁴³ The Transitional Committee initially consisted of 11 members. The number of members will expand to include an additional seat for each entity that executes an EIM implementation agreement within the period the committee is active.

⁴⁴ [Energy Imbalance Market Update](#). January 12, 2015.

⁴⁵ CAISO Market Notice. [PacifiCorp/ISO Memorandum of Understanding to Explore Full PacifiCorp Participation](#). April 14, 2015.

The CAISO and PacifiCorp provided the following in an April 14th public notice:⁴⁶

“The organizations believe there are substantial mutual benefits associated with full participation:

- *Enhanced coordination and day-ahead optimization across a broad geographic area.*
- *Coordinated planning and utilization of the two largest transmission systems in the West.*
- *Lower carbon emissions and more efficient use and integration of renewable energy resources.*
- *Enhanced reliability through broader visibility across the combined systems and better planning and management of congestion across more of the region's high-voltage transmission system.”*

“The ISO and PacifiCorp recognize that there are a number of complex policy questions to resolve that will require engagement and collaboration with numerous stakeholders:

- *Review of the governance structure due to operations across a multi-state footprint.*
- *Explore alternate transmission access charge structures for regional transmission projects.*
- *Adapt resource adequacy requirements.*
- *Expand ISO transmission planning process to include PacifiCorp area, engage state commissions.*
- *Merge generator Interconnection queues.”*

PacifiCorp is in the process of developing a feasibility and benefits study that is expected to be publicly available by the summer of 2015. Assuming the results are positive, the entities will proceed with a stakeholder process to guide the transition of PacifiCorp to full participation in the CAISO. Approval by the FERC, the ISO Board of Governors, the California legislature, and the public utility commissions in Oregon, Washington, Utah, Idaho, Wyoming, and California will be necessary. Updates will be available via the [CAISO website](#) and the [PacifiCorp website](#). The significance and scope of this undertaking cannot be overstated.

3.1.3 Northwest Power Pool Market Assessment and Coordination Committee (NWPP MC)

As discussions around a WECC-wide EIM were advancing, entities in the Northwest Power Pool formalized a sub-regional initiative to evaluate strategies to support the reliability and economic efficiency of the system in the Northwest. In March of 2012, the Northwest Power Pool Market Assessment and Coordination Committee (NWPP MC) was formed to evaluate and develop sub-regional solutions for *“operating the regional power system in a reliable and cost-effective manner as additional variable energy resources are brought onto the electric grid.”*

Figure 3-3: NWPP MC Initial Funding Organizations

• Avista Corporation	• NorthWestern Energy
• Balancing Authority of Northern California	• PacifiCorp (Phase 3 Tools)
• Bonneville Power Administration	• Portland General Electric
• BC Hydro, Powerex	• Puget Sound Energy
• Chelan County PUD	• Seattle City Light
• Clark County PUD (Phase 3 Tools)	• Snohomish County PUD
• Eugene Water & Electric Board	• Tacoma Power
• Grant County PUD (Phase 3 Tools)	• Turlock Irrigation District
• Idaho Power Company	• Western Area Power Administration, Upper Great Plains
• NaturEner Wind Holdings	

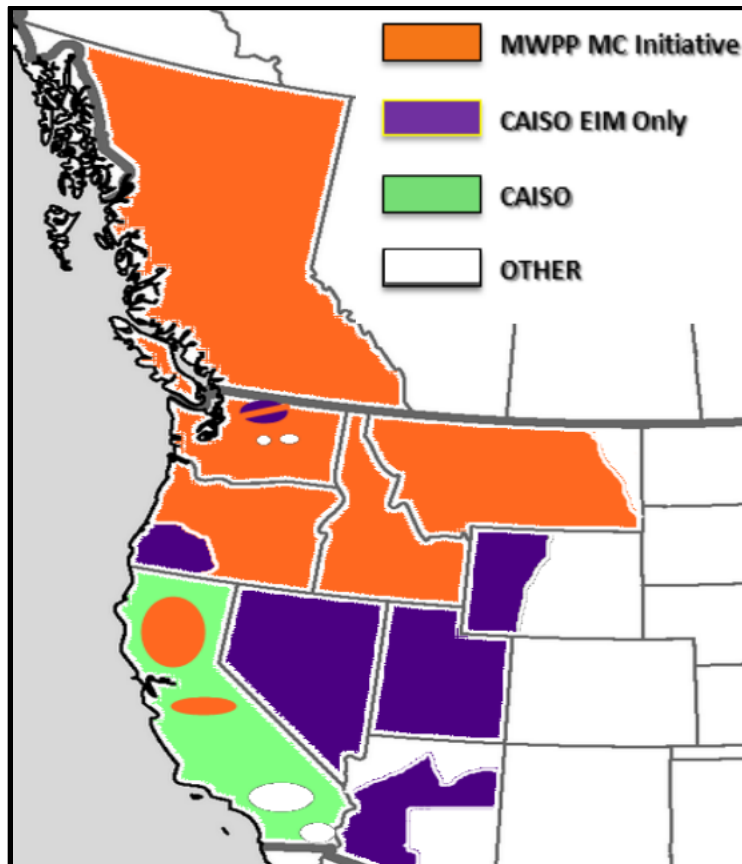
Source: [NWPP MC June 2014 Update](#)⁴⁷

⁴⁶ Ibid.

⁴⁷ PacifiCorp, Grant County, and Clark County are participants in the ongoing Phase 3 activities, but are not part of the Phase 4 funding group.

The fundamental objectives of reliability and economic efficiency are the same for the NWPP MC and the CAISO EIM, but there are important differences based on the institutions and infrastructure in the Northwest. MC members made the decision to develop their own initiative largely because of concerns that the unique characteristics of the region may not be sufficiently represented in solutions developed for others in the West. These characteristics include the role of hydropower, the high level of concentrated and export-based wind generation, the cohesiveness of the region's reserve sharing group, the value of previously implemented programs to co-optimize dispatch, and the relatively high number of transmission providers.^{48, 49} The highly engaged role of the non-jurisdictional electricity providers in the region also plays a significant role in the MC focus.

Figure 3-4: Northwest Power Pool Footprint



Source: [NWPP MC June 24, 2015 Presentation](#)

The NWPP MC is likely to be a more feasible path forward for the Northwest than the CAISO EIM because of the high number and diversity of electricity providers in the NWPP. The MC initiative includes 14 of the 38 BAs in the Interconnection and encompasses 138 utilities with approximately 38GW of load.^{50, 51}

The problem statement articulated by the MC members includes:⁵²

- *"NWPP Balancing Authorities and scheduling utilities need additional tools to respond to rapid changes in load resource balance (ramps) and the increasing demand for balancing capacity driven by the growth of variable energy resources;*

⁴⁸ [Northwest Power Pool Processes and Procedures](#). Updated October 2010.

⁴⁹ NWPP MC. [Final Phase 1 Results and Phase 2 Update](#). October 2013.

⁵⁰ [NWPP MC June 24, 2015 Presentation](#)

⁵¹ Energy Information Administration. 2012 Form 861 data.

⁵² NWPP MC. [Phase 2 Final Report](#). February 2014.

- *Utilities within the NWPP footprint are managing load and resource balance without systematically sharing the diversity between their systems; this may be resulting in increased costs and wear and tear on generating resources;*
- *The region's increasingly constrained transmission system would benefit from new tools for congestion management and more efficient use of existing infrastructure;*
- *The costs and compliance risks associated with operating a BA are increasing; this has reinvigorated conversations on potential BA consolidation among interested parties;*
- *Evolving operation measures must clearly address cost causation and cost allocation;*
- *NWPP members wish to recognize and, if possible, leverage existing platforms (such as automated sharing of contingency reserves) and innovative and valuable work from more recent initiatives within the NWPP footprint that deal with reliability, renewables integration, and transmission congestion management, including efforts by Columbia Grid, Northern Tier Transmission Group (and their joint initiative), and the Wind Integration Forum. At the same time, these efforts would benefit from greater focus, coordination, and commitment to implementation among a critical mass of utilities;*
- *It is very important to the NWPP members to preserve the value that they already receive from the existing NWPP Reserve Sharing Program."*

The MC is currently in Phase 4 of its activities. To date, the phases have included:

Phase 1: Phase 1 activities resulted in the October of 2013 release of a NWPP EIM cost-benefit analysis. The Phase 1 analysis estimated that the operational cost savings from an EIM would cluster in the \$70 million to \$80 million range and that the 10 year net present value of an EIM could range from \$1.9 million to \$377 million, with positive operational benefits and net present value for all participating entities.⁵³

Phase 2: In Phase 2, the MC engaged in a three month process to analyze the policy, technical, cost, and governance issues related to a regional EIM or an incremental solution. The Phase 2 workgroups:⁵⁴

- Did not identify any insurmountable policy hurdles.
- Recommended that the MC enter into a contract with Peak Reliability for technical aspects of the initiative.⁵⁵
- Refined the cost estimates to reflect "all in" EIM costs for the market operator, market participants, and start-up.
- Prepared draft EIM bylaws for the members to consider.

At the conclusion of Phase 2, the workgroups recommended that the members fund Phase 3 to further develop the market design, governance, and technical aspects of regional *"tools to allow enhanced reliability and improved RC integration that will enable increased inter-Balancing Authority efficiency, provide an opportunity to more economically serve customers, and provide the requisite platform for an EIM."*⁵⁶

Phase 3: Phase 3 was initiated following an additional commitment of \$4.325 million by the MC members. At this phase, the MC shifted terminology from "EIM" to "Security Constrained Economic Dispatch (SCED)."⁵⁷ As identified in a February 2014 presentation, this was done because:⁵⁸

- *"Throughout Phases 1 and 2 entities struggled with using the term "EIM" for a number of reasons;*
- *The platform being considered for the NWPP was reliability based, with a physical redispatch of offered resources, and would not be a "market" where an entity could acquire capacity or energy;*
- *The solutions targeted not only imbalance, but also a least-cost economic solution for all loads and resources;*
- *A main focus was on managing transmission capabilities to ensure reliable load service – a characteristic not overtly part of "EIM"; and*
- *In Phase 3 we have shifted to using SCED Platform or other ways of describing coordinated market solutions."*

⁵³ NWPP MC. [Final Phase 1 Results and Phase 2 Update](#). October 2013.

⁵⁴ NWPP MC. [Phase 2 Final Report](#). February 2014.

⁵⁵ Peak Reliability is the NERC-certified reliability coordinator for the Western Interconnection. Additional information on the organization is available in Section 3.5.

⁵⁶ NWPP MC. [Phase 2 Final Report](#). February 2014.

⁵⁷ The terminology has since been changed to "Automated Centrally Cleared 15-minute Energy Dispatch Market (CCED).

⁵⁸ NWPP MC. [Public Outreach Meeting Presentation](#). February 2014.

As part of the Phase 3 activities, the MC issued an RFP for a SCED market operator on October 31, 2014. The Southwest Power Pool Energy Imbalance Service (EIS)⁵⁹ market was chosen as the basis for the design of the SCED. A presentation given October 9, 2014 indicates that this is due to the “*similarities between the current state of the NWPP and where the Southwest Power Pool was when they designed their EIS market.*”⁶⁰ The decision to issue the RFP did not commit the members to proceed with a SCED, but rather sought to provide the group with additional cost information for consideration. The target date for the selection of a proposal was scheduled to be in February and the MC had planned to request a declaratory order from FERC in the spring on matters related to FERC oversight of non-jurisdictional electricity providers within the context of a regional imbalance market.

On February 20, 2015 the NWPP MC provided a public notice that the proposals received from the CAISO and the Southwest Power Pool “*provided significant challenges relative to the desired goals of the NWPP MC. On February 17, 2015 the NWPP MC Executive Committee unanimously agreed to close the RFP without selecting either of the two proposals as submitted. The Executives requested additional due diligence to assess whether either of the proposals may be made more compatible with the NWPP MC Members’ near- and long-term business objectives. To that end, the NWPP MC will continue to engage with both the Southwest Power Pool and the CAISO throughout 2015 to explore whether and how either could partner with the NWPP MC members to deliver future within-hour solutions.*”

There have been concerns that the NWPP MC SCED/EIM effort might lose traction and may not result in a tangible market outcome. On November 12, 2014 the Oregon Public Utilities Commission directed Portland General Electric “*to thoroughly evaluate the costs and benefits of joining the PacifiCorp-CAISO EIM as a way of augmenting their system flexible capacity, and to compare the option of joining the CAISO EIM with other EIM options they might be considering.*”⁶¹ Evaluation of the CAISO EIM is proceeding in parallel with the development of the NWPP MC tools.

Phase 4: Phase 4 was initiated in January of 2015 with an additional member commitment of \$2 million.⁶² On June 2, 2015 the MC announced that the members have unanimously “*agreed on a set of market tools and operating agreements to improve the reliability and efficiency of the region’s energy system.*” The target for final implementation is 2016 to 2017. Select items from the Executive Committee resolution indicate that “*The organizations... will take the following actions in the period between May 29, 2015 and December 31, 2015:*

- *Develop Automated Centrally Cleared 15-Minute Energy Dispatch Market with Flexible Platform for Future Options with a target market go live date of late 2017.*
- *Evaluate expansion of ACE Diversity Interchange Program and Exploration of Regulation Sharing.*
- *Evaluate Coordination of Transmission Owner, Transmission Operator, and Transmission Service Provider Functions to identify opportunities to improve the efficiency of and otherwise enhance how they provide and manage transmission services, as well as how they carry out transmission operations.”*⁶³ ⁶⁴

Table 3-6: NWPP MC Chronology

Date	Description
Mar 2012	The NWPP MC launched an initiative to evaluate a range of alternatives to help the BAs better manage growing operational and commercial challenges.
May 2012	The National Renewable Energy Laboratory released an analysis of <u>Operating Reserve Reductions From a Proposed Energy Imbalance Market With Wind and Solar Generation in the Western Interconnection</u> for the Western Interconnection.

⁵⁹ The Southwest Power Pool Energy Imbalance Service (EIS) was fundamentally an IEM. It was subsumed in 2014 by the SPP transition to a fully integrated market.

⁶⁰ NWPP MC. [Presentation on Draft SCED RFP](#). October 2014.

⁶¹ Oregon PUC Staff Report. [Commission acknowledgement of Portland General Electric’s 2013 Integrated Resource Plan](#). November 12, 2014.

⁶² PacifiCorp, Grant County, and Clark County withdrew from the membership prior to the additional funding commitment.

⁶³ [Unanimous Resolution of The Executive Committee for Phase 4 of the Northwest Power Pool Members’ Market Assessment and Coordination Initiative](#). NWPP MC. May 29, 2015

⁶⁴ [NWPP MC June 24, 2015 Presentation](#)

Feb 2013	FERC released a Qualitative Assessment of Potential Reliability Benefits from a Western Energy Imbalance Market .
Mar 2013	National Renewable Energy Laboratory released a BA-level Examination of Potential Benefits of an Energy Imbalance Market in the Western Interconnection .
Oct 2013	The Pacific Northwest National Laboratory released the NWPP MC-contracted Analysis of Benefits of an Energy Imbalance Market in the NWPP .
Oct 2013	The NWPP released their Phase 1 Final Report and Phase 2 Update .
Feb 2014	The NWPP MC released their Phase 2 Report and initiated Phase 3 to develop a comprehensive Security Constrained Economic Dispatch (SCED) framework.
Oct 31, 2014	The NWPP MC released a Request for Proposal for Market Operator .
Feb 2015	The NWPP MC issued a news release that the entities had closed the RFP without selecting a bidder and would continue to engage with the CAISO and the Southwest Power Pool regarding the proposals.
Apr 2015	The NWPP MC provided a public presentation indicating that the members have committed additional funding through December of 2015.
June 2015	The NWPP MC provided a public presentation on a member-approved “ <i>set of market tools and operating agreements to improve the reliability and efficiency of the region’s energy system.</i> ”
Ongoing	Throughout the process, the NWPP MC has held periodic public stakeholder meetings. Information from those meetings and updates are available via the NWPP MC webpages .

3.1.4 Mountain West Network Tariff

Seven entities along the Front Range are in negotiations to develop a Mountain West Network Tariff. The network tariff would significantly modify the terms by which the entities sell access to their respective transmission systems and would centralize certain aspects of the operations. The network would be managed and the tariff administered by a single entity. Historically, common tariffs have also significantly aided regional transmission planning and cost allocation. The Mountain West Network Tariff entities are:

- Public Service Company of Colorado
- Western Area Power Administration
- Tri-State Generation and Transmission Association
- Basin Electric
- Black Hills Corporation
- Platte River Power Authority
- Colorado Springs Utilities

Across the West, there are two primary types of transmission service: Point-to-point and network. With point-to-point service, transmission customers purchase contract paths between a point of receipt and a point of delivery. With network service, the transmission customer purchases access to the transmission provider’s full network without being required to designate specific points of generation or load.⁶⁵

Currently, point-to-point and network service are offered individually by the Mountain West transmission providers and customers are required to transact separately for each service territory they intend to move power within or across. The Mountain West Network Tariff would allow transmission customers to purchase network service for the combined footprint.

A network tariff along the Front Range would:

- Enhance reliability by reducing unscheduled flows between the systems. This is because there would be one entity managing the combined transmission assets and that entity would have both better visibility to system conditions and enhanced operational control.

⁶⁵ This is a highly simplified explanation and more detail is available in the [FERC Pro-Forma Open Access Transmission Tariff](#).

- Allow the system operators to net their Area Control Error (ACE), which would result in reliability and economic benefits.
- Facilitate the utilization of the lowest cost generation options, frequently renewable resources, within the combined footprint by reducing transactional friction.
- Reduce ‘pancaking’ of transmission charges for entities that desire to move power across multiple systems.
- Provide optionality for an RTO and/or regional markets if the entities choose to pursue one or both in the future.

Figure 3-5: Mountain West Network Tariff Footprint



Source: [PSCO presentation to the Colorado PUC. March 19, 2015.](#)

If the parties are able to come to agreement about terms for the Mountain West Network Tariff, it would likely take one to three years to fully implement. The Mountain West Tariff has many similarities to the Integrated Transmission System (IS) formed in the Upper Great Plains region which resulted over time in the participating entities decision to join the Southwest Power Pool. The following section discusses this initiative.

3.1.5 The Integrated System Tariff and Western’s Participation in the Southwest Power Pool

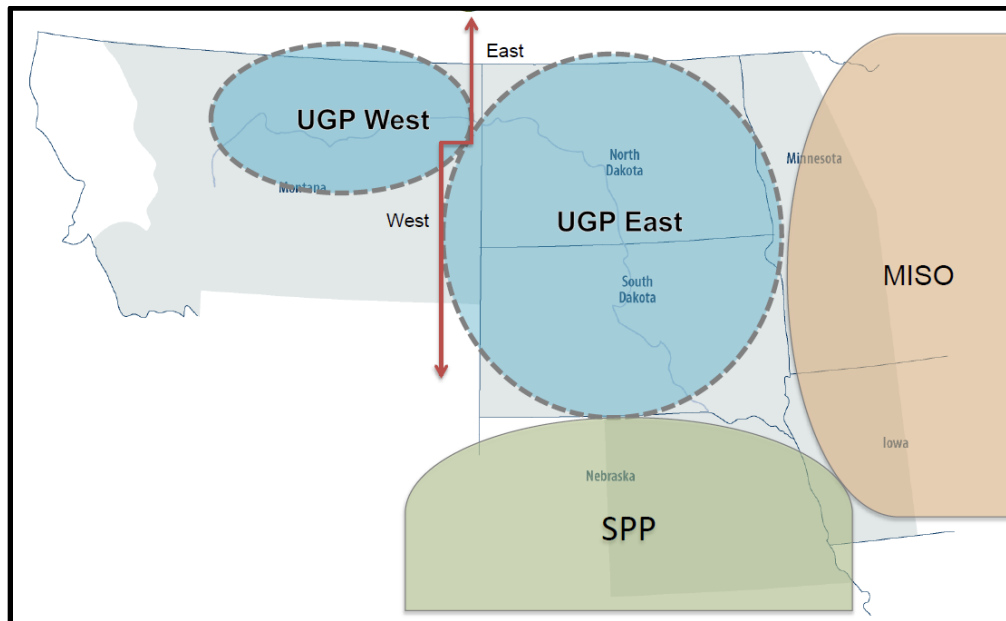
Pooling of transmission operations and development of integrated tariffs is not new in the West. In 1998, the Western Area Power Administration’s Upper Great Plains Region (Western-UGP), Basin Electric Power Cooperative, and Heartland Consumers Power District formed the Integrated Transmission System (IS) to improve the efficiency and reliability of their collective resources. The IS represents a multi-lateral agreement to have one transmission operator (Western) administer the physical and tariff aspects of the transmission systems for multiple entities. The IS includes approximately 9,800 miles of transmission located in both the Western and Eastern Interconnections.⁶⁶ In addition to providing a means for participants to improve the efficiency and reliability of their existing assets, the IS facilitates transmission planning and cost allocation within its footprint. The IS functioned as intended for

⁶⁶ [Western Area Power Administration Federal Register Notice](#). November 1, 2013.

operational and planning purposes, but the entities found over time that their access to bilateral trading partners was diminishing and that the need for access to markets was sufficiently compelling to motivate the transition into an existing RTO with a centralized market.

After fifteen years of operations, the IS participants filed with FERC in November of 2013 to join the Southwest Power Pool and FERC approved the application in November of 2014. The tested IS framework and the comfort level of the participants with the common tariff significantly aided the entities' evaluation and decision processes. Economic benefits to participants for joining the Southwest Power Pool are expected to range from \$11.5 to \$14.2 million in addition to the IS benefits.⁶⁷ Western is the first federal agency to join an RTO.

Figure 3-6: Upper Great Plains, the Southwest Power Pool, and the Midcontinent Independent System Operator



Source: [Western Area Power Administration February 2014 Presentation](#)

From the November of 2014 FERC news release.⁶⁸

FERC Accepts Proposal to Integrate WAPA, Basin Electric, Heartland as New the Southwest Power Pool Members

"The Federal Energy Regulatory Commission (FERC) today significantly expanded the Southwest Power Pool, Inc. (the Southwest Power Pool) market by accepting the Southwest Power Pool's proposal to integrate Western Area Power Administration - Upper Great Plains Region, Basin Electric Power Cooperative and Heartland Consumers Power District into the Southwest Power Pool.

Today's Commission decision expands the geographic footprint of the regional power market to include a significant portion of the Upper Great Plains that spans the Eastern and Western Interconnections of the U.S. electric grid. According to Chairman Cheryl LaFleur, "Today's order is a positive step that greatly expands customer access to organized markets, particularly in the upper-Midwest region, and increases efficiency and reliability for the newly combined market."

The area of the Western Area Power Administration to be included in this new portion of the Southwest Power Pool is known as Western-UGP, for Western-Upper Great Plains, which owns an extensive system of high-voltage transmission facilities and markets federally generated hydropower in the Pick-Sloan Missouri-Basin Program-

⁶⁷ UGPR Membership in the Southwest Power Pool: Alternative Operations Study Recommendation. January 2014.

⁶⁸ [FERC Accepts Proposal to Integrate WAPA, Basin Electric, Heartland as New the Southwest Power Pool Members](#). News Release. November 10, 2014.

Eastern Division of Western. Basin Electric serves 2.8 million customers in territories covering approximately 540,000 square miles using nearly 2,100 miles of transmission lines and 70 switch yards. Heartland is a public corporation and political subdivision of the State of South Dakota. It provides wholesale power to 28 municipalities in Eastern South Dakota, southwest Minnesota, and northwest Iowa, to six South Dakota state agencies, and to one electric cooperative in South Dakota.

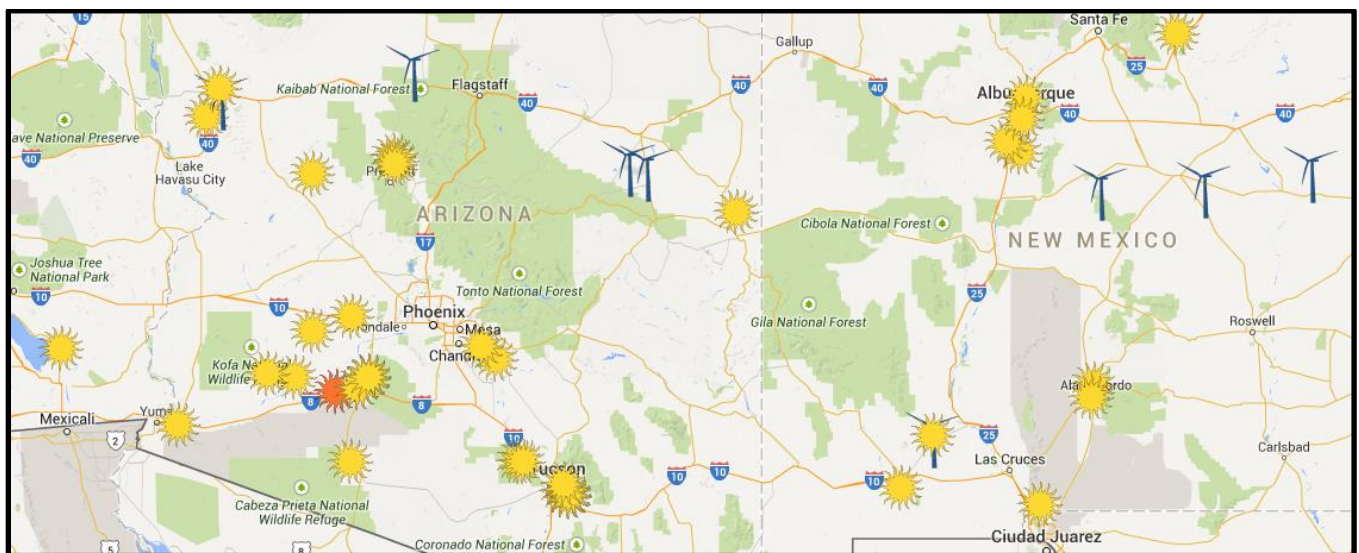
Together, these new the Southwest Power Pool members provide the backbone of the bulk electric transmission system across seven states in the Upper Great Plains region consisting of approximately 9,500 miles of transmission lines.”

The Southwest Power Pool began providing reliability coordination to the IS on June 1st and will fully integrate the system into its markets in October of 2015.⁶⁹

3.1.6 Southwest Variable Energy Resources Initiative (SVERI)

The SVERI⁷⁰ was formed in the fall of 2012 to evaluate the potential characteristics of variable energy in the Southwest over the next 20 years and to explore tools that may facilitate variable energy resource integration. The SVERI is comprised of four non-jurisdictional public power entities and four investor-owned utilities which include Arizona's G&T Cooperatives, Arizona Public Service (APS), El Paso Electric (EPE), Imperial Irrigation District (IID), Public Service Company of New Mexico (PNM), Salt River Project (SRP), Tucson Electric Power (TEP), and the Western Area Power Administration's Desert Southwest Region (WAPA DSW).

Figure 3-7: SVERI Footprint



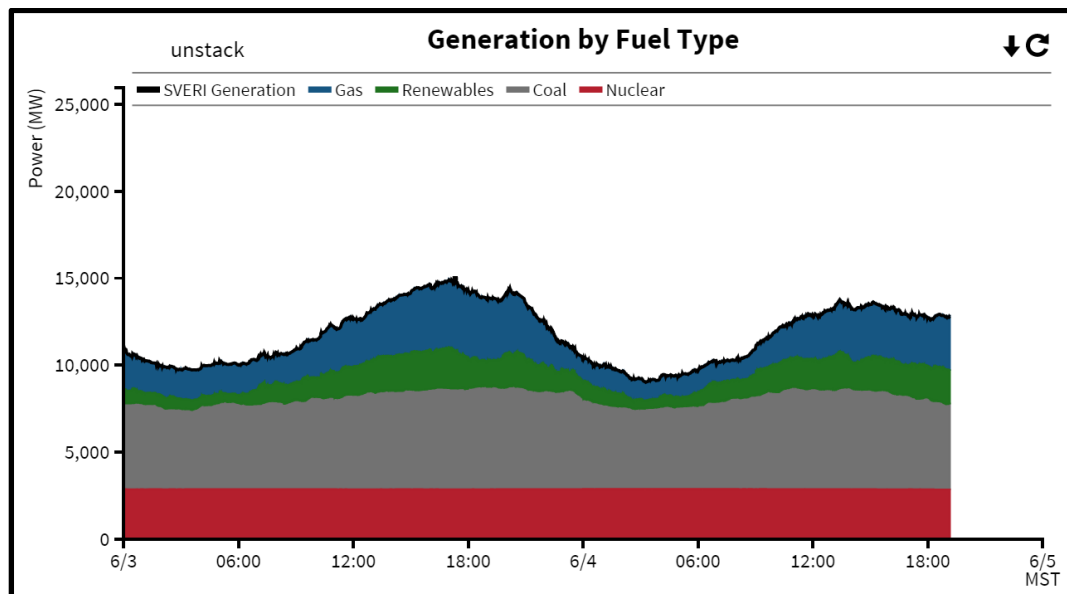
Source: <https://sveri.uaren.org/>

The formation of the SVERI was at least partially motivated by the EIM discussions in public forums and a desire by entities in the Southwest to develop a formal collaboration to represent the collective interests of the group. The Southwest, like the Northwest, has a high degree of cohesion between the non-jurisdictional electricity providers and is conservative in its approach to changes in system operations and infrastructure. The SVERI is also similar to the NWPP MC in that the membership mirrors the region's reserve sharing group. The reserve sharing groups across the Interconnection have long histories of collaboration and trust and have become default coalitions for the development of reliability and renewable integration strategies in both the Northwest and the Southwest.

⁶⁹ SPP Press Release. [Southwest Power Pool expands electric grid management to 14 states](#). June 2015.

⁷⁰ Additional information about the SVERI is available via the [public access data portal](#).

Figure 3-8: Sample SVERI Website Graphics



Source: <https://sveri.uaren.org>

Current activities within the SVERI include:^{71, 72}

- In 2013, the members entered into an agreement to share load and generation data with a third party for the purposes of standardizing data feeds, developing the ability of the entities to consolidate and analyze operational information, and creating a data access portal. The SVERI entered into a contract with the University of Arizona and launched a data access website in May of 2014. The website provides graphics and downloadable generation and load data in 10 second granularity for the consolidated footprint. The members have access to their own data and the consolidated data, but no member has access to the disaggregated data of the other members.
- Phase II of the partnership with the University of Arizona is focused on evaluating distributed PV, forecasting, ramping, and regulation requirements. The group is updating their typical day analysis and performing an evaluation of tools including Area Control Error (ACE)⁷³ Diversity Interchange (ADI)⁷⁴, Dynamic System Scheduling (DSS), and the Intra-hour Transaction Accelerator Platform (ITAP).⁷⁵
- Future work, which will be explored after the Phase II analytics are completed, will evaluate additional operational enhancements for regional collaboration.
- Arizona Public Service and the Salt River Project have implemented an ADI. Described by Arizona Public Service as a meaningful and beneficial step that can be taken in the short run, the ADI is fundamentally a mechanism by which the BAs net their ACE and leverage the geographic dispersion of loads and resources to reduce the

⁷¹ Arizona Public Service. [Grid Flexibility Strategies Presentation](#). October 10, 2014.

⁷² <https://sveri.uaren.org/>

⁷³ Area Control Error (ACE) is a real-time measurement of the performance of the system. It is a complex calculation that can roughly be approximated by the difference between a BAs net scheduled interchange (flow of power between neighboring BAs) and actual interchange. (NERC) Failure to maintain ACE within a narrow tolerance band can lead to reliability issues. Each BA is responsible for maintaining the ACE in its control area.

⁷⁴ An ACE Diversity Interchange (ADI) is an agreement between two or more BAs to net their ACE. This leverages the benefits of geographic diversity to manage system variability.

⁷⁵ ADI, DSS, and I-Tap were part of the Joint Initiatives, an effort by multiple balancing authorities in the West to evaluate tools to leverage the flexibility and diversity of their respective systems to promote reliability. The Joint Initiatives included trial changes to "Transmission Service Provider business practices to allow for within-hour transmission purchase and scheduling, developing tools to facilitate within-hour bilateral transactions, and developing a dynamic scheduling system consisting of standard protocols and communication infrastructure that would allow access to resources across multiple balancing authorities, subject only to transmission constraints." ([March 2009 WECC comments to FERC](#).) Regional evaluation of the Joint Initiatives faded over time and has largely been replaced by consideration of the more advanced EIM and NWPP MC tools.

need for entities to adjust generation in real time to balance supply and demand. The ADI creates both reliability benefits and operational savings. Arizona Public Service and the Salt River Project characterize the program as a low-barrier tool to support reliability and system efficiency, and are actively encouraging other entities in the Southwest to participate.

- In January of 2015, the SVERI released an analysis that evaluates renewable penetrations, ramp characteristics, and net load for 2014, 2017, 2020, 2022, and 2027 for the SVERI member footprint.⁷⁶
- In April of 2015, Arizona Public Service released a report that evaluates the benefits of the entity's potential participation in the CAISO EIM⁷⁷ and in May the company announced that it intends to participate in the CAISO EIM beginning in October of 2016.

3.2 FERC ORDER 1000 TRANSMISSION PLANNING AND COST ALLOCATION

FERC Order 1000 on transmission planning and cost allocation was finalized in October of 2012 and is intended to reform deficiencies in transmission planning and cost allocation.⁷⁸ In the Western Interconnection, the Order is expected to facilitate both reliability and renewable integration by requiring transmission owners to participate in intra-regional transmission planning that includes consideration of public policy requirements and non-transmission alternatives. In order to develop infrastructure that moves beyond business as usual and simply replaces retiring coal units with gas units, a paradigm shift in resource planning will be necessary. A primary focus of the current Order 1000 activities is on developing and refining substantively revised planning processes to enable that shift.

Figure 3-9: Summary of FERC Order 1000 Reforms

Planning Reforms

The rule establishes three requirements for transmission planning:

- Each public utility transmission provider must participate in a regional transmission planning process that satisfies the transmission planning principles of Order No. 890 and produces a regional transmission plan.
- Local and regional transmission planning processes must consider transmission needs driven by public policy requirements established by state or federal laws or regulations. Each public utility transmission provider must establish procedures to identify transmission needs driven by public policy requirements and evaluate proposed solutions to those transmission needs.
- Public utility transmission providers in each pair of neighboring transmission planning regions must coordinate to determine if there are more efficient or cost-effective solutions to their mutual transmission needs.

Cost Allocation Reforms

The rule establishes three requirements for transmission cost allocation:

- Each public utility transmission provider must participate in a regional transmission planning process that has a regional cost allocation method for new transmission facilities selected in the regional transmission plan for purposes of cost allocation. The method must satisfy six regional cost allocation principles.
- Public utility transmission providers in neighboring transmission planning regions must have a common interregional cost allocation method for new interregional transmission facilities that the regions determine to be efficient or cost-effective. The method must satisfy six similar interregional cost allocation principles.
- Participant-funding of new transmission facilities is permitted, but is not allowed as the regional or interregional cost allocation method.

Source: [FERC Order 1000 web pages](#)

As the BES infrastructure shifts away from its orientation around large coal-fired generating units and towards more dispersed clean energy resources, transmission planning will become increasingly complex. Long term development of transmission infrastructure that fully incorporates federal and state policies, the resulting shifts in

⁷⁶ [SVERI Load Shape Analysis](#), January 2015.

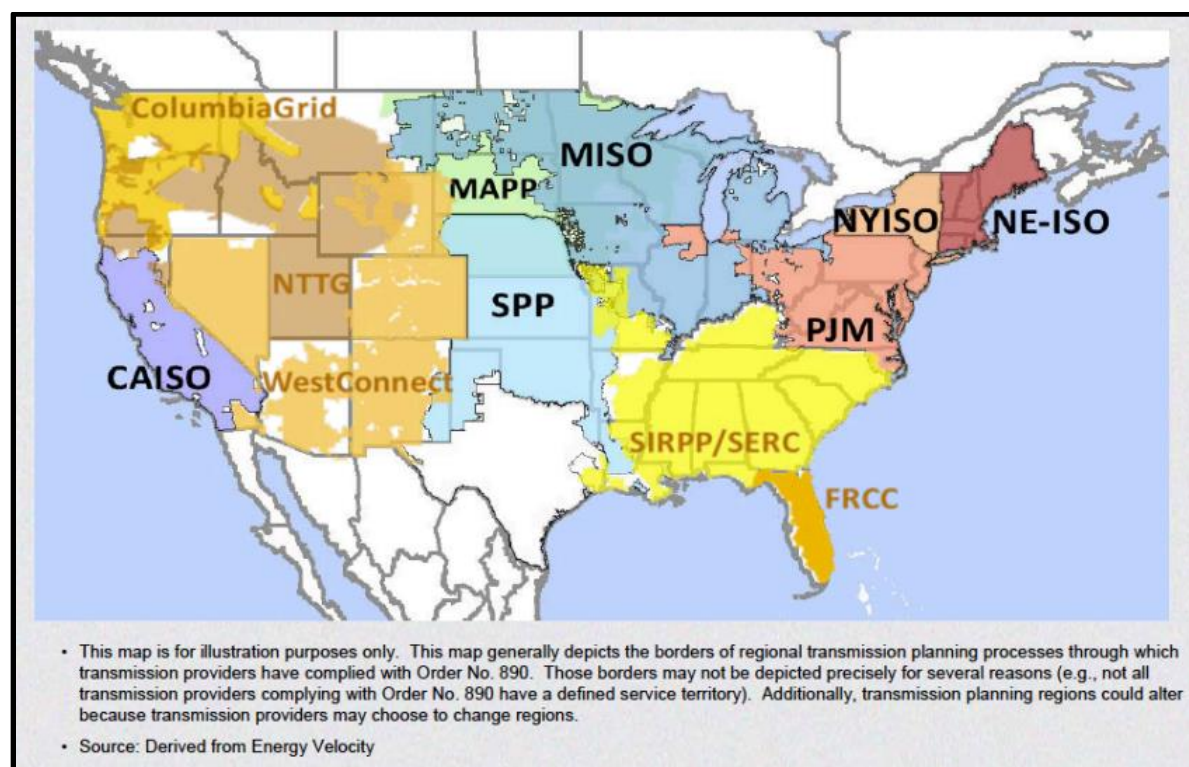
⁷⁷ [Arizona Public Service EIM Benefits Analysis](#), April 2015.

⁷⁸ [FERC Order 1000b](#)

supply and demand characteristics, and technology advancements will rely upon near term success in establishing new business practices within the planning groups. Because of the long lead times for transmission relative to generation development, it is exceptionally important that transmission planning be done both effectively and efficiently in a manner that fully incorporates public policy priorities such as renewable energy standards, energy efficiency requirements, deployment of distributed resources, and greenhouse gas reductions.

Within the Western Interconnection, there are four planning regions: the CAISO, Columbia Grid, Northern Tier Transmission Group (NTTG), and WestConnect. Prior to Order 1000, each of the regions had structures for transmission planning within their respective footprints. Only the CAISO had formal cost allocation procedures. The frameworks have historically varied dramatically by region and when Order 1000 became effective the regions were required to amend or create new agreements as necessary to align with the basic requirements of the Order.

Figure 3-10: U.S. Transmission Planning Regions



Source: [FERC Presentation: Final Rule on Transmission Planning and Cost Allocation](#)

Of the four planning regions in the Western Interconnection:

- CAISO has the most codified structure.
- NTTG and Columbia Grid were able to implement relatively minor modifications to their agreements to align with FERC compliance requirements.
- WestConnect, as the largest and most geographically diverse region, had the least formal processes prior to the Order and has made major modifications to its governance and business practices.

Highlights of the regional characteristics for WestConnect, Columbia Grid, and NTTG are included in the following sections. The CAISO, as an independent system operator, has planning processes that are substantively different from the rest of the Western Interconnection. CAISO Order 1000 activities are not included in this document but are available via the CAISO website.⁷⁹

⁷⁹ [CAISO FERC Order 1000 compliance web pages.](#)

Table 3-7: ICF Regional Transmission Planning Overview

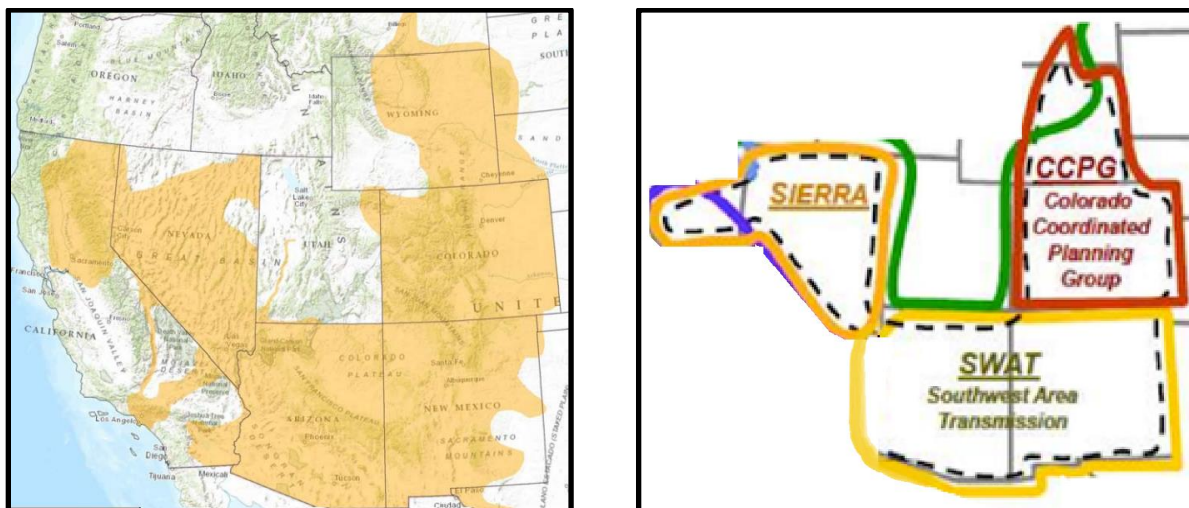
	Western Interconnection				Eastern Interconnection	
	CAISO	NTTG	ColumbiaGrid	WestConnect	SPP	MISO
Region Overview						
No. of Planning Parties	16	6	11	13	16 Transmission Owner members	50 Transmission Owner members
States Spanned	CA	CA, ID, MT, OR, WA, WY, UT	WA, OR, ID, MT	AZ, CA, CO, MT, NM, NV, TX, UT, WY	8 states	15 states
Approximate Peak Demand, 2014 (GW)	47 GW (coincident)	22 GW (estimated coincident)	22 GW (estimated coincident)	56 GW (2012 non-coincident)	49 GW (coincident)	96 GW (coincident)
Customers Served	30 Million	4 Million	3 Million	10 Million	15 Million	42 Million
Miles of High Voltage Transmission	26,000	29,000	22,000	40,000	49,000	50,000
Order 1000 Compliance Status						
Regional	Fully compliant	Fully compliant	Awaiting FERC Order, tariff changes effective 1/1/15	Awaiting FERC Order, tariff changes effective 1/1/15	Awaiting FERC Order, tariff changes effective 3/30/14	Awaiting FERC Order, tariff changes effective 6/1/2013
Interregional	Awaiting FERC Order, tariff changes effective 10/1/15	Awaiting FERC Order, tariff changes effective 10/1/15	Awaiting FERC Order, tariff changes effective 1/1/15	Awaiting FERC Order, tariff changes effective 10/1/15	Awaiting FERC Order, tariff changes effective 3/30/14 for SPP-MISO, 1/1/15 for SPP-SERTP	Awaiting FERC Order, tariff changes effective 3/30/14 for SPP-MISO, 1/1/15 for MISO-SERTP, 1/1/2014 MISO-PJM
Regional Planning Process						
Planning Cycle	Annual	Biennial	Biennial, Annual study program	Biennial	Triennial, Annual near-term studies	Annual
Governance and Direction of Planning Activities	Board of Directors	Steering Committee	Board of Directors	Planning Management Committee	Board of Directors	Board of Directors, System Planning Committee
Method for Participation by States	Stakeholder	Committee Membership	Stakeholder, Study Team Participant	PMC Member	Stakeholder	Stakeholder

Source: ICF International. [Western Planning Regional and Transmission Planning Coordination](#). April 2015.

WESTCONNECT

WestConnect's FERC Order 1000 compliance processes have been more involved than the other regions due to the size of the footprint (see table on the preceding page) and the organization's historically less formal structure. Prior to Order 1000, WestConnect produced rolling 10-year transmission plans for the entity as a whole and for its three sub-regions: the Colorado Coordinated Planning Group (CCPG), the Sierra Subregional Planning Group (Sierra), and the Southwest Transmission Planning Group (SWAT). The full WestConnect plan was fundamentally a roll up of the sub-regional plans.

Figure 3-11: WestConnect Footprint and WestConnect Sub-Regional Planning Areas



Source: [WestConnect Draft Business Practice Manual](#) and [Transmission Hub](#)

Following the promulgation of Order 1000, the region engaged in extensive stakeholder processes to develop a new organizational structure with significantly revised business practices. The WestConnect utilities made their initial Order 1000 compliance filings in October of 2012. Those were followed by extensive iterations of interventions, requests for rehearing, FERC orders, and interim compliance filings.

After a two plus year process, WestConnect received final FERC approval of its Order 1000 compliance filings on June 1, 2015. One of the key compliance elements is the Planning Participation Agreement. The agreement was the subject of lengthy negotiations between the utilities, state regulators, and other industry stakeholders. The agreement creates a WestConnect Order No. 1000 regional transmission Planning Management Committee (PMC) that is responsible for administering the new WestConnect regional planning process. By December 11, 2014 WestConnect had received a sufficient number of signatures from transmission owners to make the agreement effective and an organizational meeting for the Order 1000 PMC was held on December 16th.

The membership Classes are:⁸⁰

Class 1: Transmission owner members with load serving obligations⁸¹

Class 2: Transmission customers

Class 3: Independent transmission developers and owners

Class 4: State regulatory commissions

Class 5: Key interest groups

⁸⁰ The membership provisions and the Class delineations are critical for all of the planning regions because they identify who gets to participate in the processes and who gets to vote.

⁸¹ Class 1 has two sub-groups. Class 1.a. includes members that enroll in the transmission owner sector for purposes of cost allocation pursuant to Order 1000 (Enrolled Transmission Owners) and Class 1.b. includes members that join the transmission owner sector without enrolling for Order 1000 cost allocation purposes (Coordinating Transmission Owners.)

WestConnect entities that are eligible for Class 1 membership include:

- Arizona Public Service Company
- Basin Electric
- Black Hills Colorado Electric Utility Company
- Black Hills Power
- Cheyenne Light, Fuel, and Power Company
- El Paso Electric Company
- Imperial Irrigation District
- NV Energy
- Public Service Company of New Mexico
- Sacramento Municipal Utility District
- Salt River Project
- Southwest Transmission Cooperative
- Transmission Agency of Northern California
- Tucson Electric Power Company
- UNS Electric
- Western Area Power Administration
- Xcel Energy/ PSCO

Within each Class, there is one vote allocated to each member. For the PMC to approve any matter, a 75% majority in at least three membership sectors, one of which must be the transmission owner sector, must vote in favor of the proposal. Alternatively, if two-thirds of the transmission owner sector votes for a proposal and at least 75% of the members in four other member sectors approve the proposal, the proposal will be approved.

As part of the September 2014 FERC Order, WestConnect is required to perform an abbreviated planning cycle in 2015. The organization released a 2015 Regional Study Plan on January 6th and is in the process developing 10-year plans.⁸²

NORTHERN TIER TRANSMISSION GROUP (NTTG)

The NTTG and Columbia Grid share the Northwest, with NTTG focused on the East side and Columbia Grid on the West side. NTTG includes Deseret Generation and Transmission, Idaho Power, Northwestern, PacifiCorp, and Portland General Electric. The NTTG regional planning processes are described as being less complicated than those of Columbia Grid and the group made only minor modifications to its agreements to align with Order 1000 requirements.

The NTTG compliance filings were approved by FERC in 2014 and the 2014-2015 Draft Regional Transmission Plan was posted for public comment on December 31, 2014.⁸³ The NTTG has three primary committees: the Steering Committee, the Planning Committee, and the Cost Allocation Committee. For each of the Committees, each member is entitled to one equally weighted vote. The Class designations and membership rosters as of November 2014 are included below.

⁸² [WestConnect 2015 Regional Study Plan](#). January 6, 2015.

⁸³ [NTTG 2014-2015 Draft Regional Transmission Plan](#). December 31, 2014.

Figure 3-12: Northern Tier Transmission Group Facilities



Source: [NTTG website](#)

NTTG Steering Committee:⁸⁴

Class 1: Entities enrolled in Northern Tier as a full funder or nominal funder.

Class 2: State utility commissions, state customer advocates, or state transmission siting agencies within the Northern Tier Footprint (the Regulators).

Steering Committee	
Membership	
• Travis Kavulla - State Co-Chair, Montana Public Service Commission	
• David Clark - State Vice Co-Chair, Utah Public Service Commission	
• Ray Brush - Utility Co-Chair, NorthWestern Energy Corporation	
• Rick Vail - Utility Vice Co-Chair, PacifiCorp	
• Michele Beck - Utah Office of Consumer Services	
• Larry Bekkedahl - Portland General Electric	
• Marshall Empey - Utah Associated Municipal Power Systems (UAMPS)	
• Larry Nordell - Montana Consumer Counsel	
• Adam Richins - Idaho Power Company	
• Bill Russell - Wyoming Public Service Commission	
• John Savage - Public Utility Commission of Oregon	
• Marsha Smith - Idaho Public Utilities Commission	
• Curt Winterfeld - Deseret Power Electric Cooperative	

Source: [NTTG website](#)

⁸⁴ [NTTG Steering Committee Charter](#). August 2013.

NTTG Planning Committee:⁸⁵

Class 1: Transmission providers or transmission developers engaged in or intending to engage in the sale of electric transmission service within the Northern Tier Footprint (the Transmission Provider/Developer Class).

Class 2: Transmission users engaged in the purchase of electric transmission service within the Northern Tier Footprint, or other entity, which has, or intends to enter into, an Interconnection agreement with a transmission provider within the Northern Tier footprint (the Transmission User Class).

Class 3: State utility commissions, state customer advocates, or state transmission siting agencies within the Northern Tier Footprint (collectively, the Regulators, and the Regulatory Class).

Planning Committee Membership

- Dave Angell - Chair, Idaho Power
- Craig Quist - Vice Chair, PacifiCorp
- Johanna Bell - Idaho Public Utilities Commission
- John Chatburn - Idaho Office of Energy Resources
- Bob Decker - Montana Public Service Commission
- Marshall Empey - UAMPS
- Bill Hosie - TransCanada
- Rhett Hurless - Absaroka Energy LLC
- Don Johnson - Portland General Electric
- Rodney L. Lenfest - Sea Breeze Pacific - Regional Transmission System
- Chelsea Loomis - NorthWestern Energy
- Jerry Maio - Utah Public Service Commission
- Jim Tucker - Deseret Power Electric Cooperative
- David Walker - Wyoming Public Service Commission
- Scott Waples - Avista Corporation
- Dan Wheeler - Gaelectric, LLC
- Wes Wingen - Black Hills Power

Source: [NTTG website](#)

NTTG Cost Allocation Committee:⁸⁶

Class 1: Entities enrolled in Northern Tier as a funder and that have appointed a representative to the Steering Committee.

Class 2: State utility commissions, state consumer advocates, or state transmission siting agencies within the Northern Tier Footprint that have appointed a representative to the Steering Committee (the Regulators).

Cost Allocation Committee Membership

- Sarah Edmonds - Chair, PacifiCorp
- Amy Light - Vice Chair, Portland General
- Johanna Bell - Idaho Public Utilities Commission
- Ray Brush - NorthWestern Energy
- Bob Decker - Montana Public Service Commission
- Marshall Empey - UAMPS
- Belinda Kolb - Wyoming Office of Consumer Advocates
- Marci Norby - Wyoming Public Service Commission
- Larry Nordell - Montana Consumer Council
- Bela Vastag - Utah Office of Consumer Services
- Courtney Waite - Idaho Power
- Curt Winterfeld - Deseret G&T
- Joni Zenger - Utah Public Service Commission

Source: [NTTG website](#)

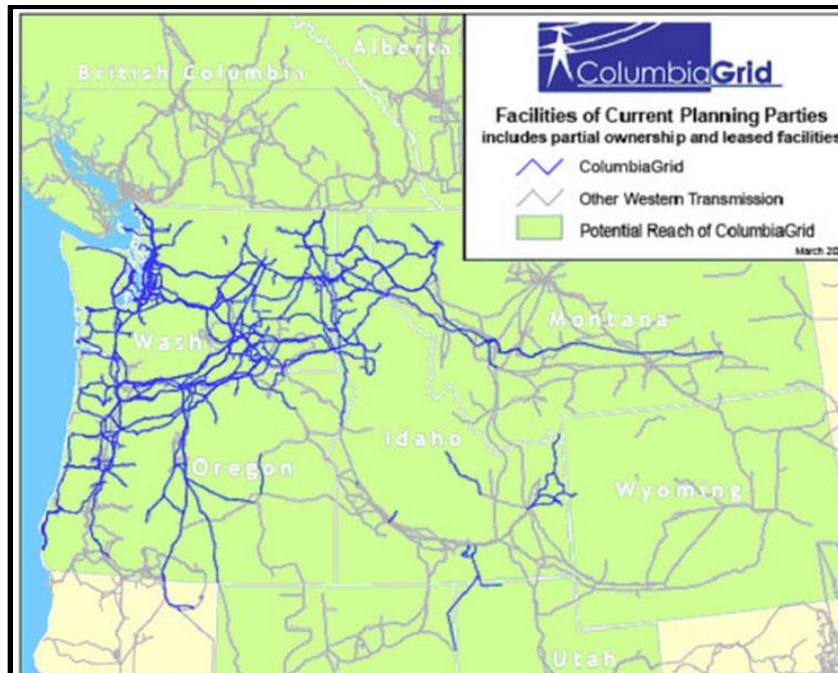
⁸⁵ [NTTG Planning Committee Charter](#). August 2013.

⁸⁶ [NTTG Cost Allocation Committee Charter](#). August 2013.

COLUMBIA GRID

Columbia Grid members include both investor-owned and non-jurisdictional entities. The politics between the groups can be problematic. BPA is not bound to comply with Order 1000 and their participation in both the planning processes and the cost allocation is voluntary. Because of BPA's size, the voluntary nature of their participation effectively gives them veto power over large transmission projects that could be subject to cost allocation.

Figure 3-13: Columbia Grid Transmission Facilities



Source: [Columbia Grid](#)

Only participating entities are eligible to vote on matters related to Order 1000. The planning documents identify a stakeholder role for regulators and special interest groups but these groups do not have voting rights.⁸⁷ Columbia Grid entities include:

- Avista Corporation
- Bonneville Power Administration
- Chelan County Public Utility District
- Grant County Public Utility District
- Puget Sound Energy
- Seattle City Light
- Snohomish County Public Utility District
- Tacoma Power

In November of 2014, Columbia Grid's jurisdictional transmission providers filed Order 1000 agreements which will operate in tandem with the Columbia Grid Planning and Expansion Functional Agreement. A 2014-2015 Draft Regional Plan was posted on December 23rd and a regional meeting was held February 5th.

⁸⁷ [Columbia Grid Order 1000 Functional Agreement](#), November 2014.

3.3 POWER MARKETING ADMINISTRATIONS AND OTHER NON-JURISDICTIONAL ELECTRICITY PROVIDERS

The Western Area Power Administration (Western), the Bonneville Power Administration (BPA), and other non-jurisdictional electricity providers are foundational participants for the development of regional operating agreements, coordinated transmission planning, and markets in the West.

To highlight the breadth and depth of non-jurisdictional entities in the West:

- Non-jurisdictional utilities own 39% of the high voltage transmission lines (200kV and above) in the Interconnection.
- BPA owns or operates 15,000 miles of transmission in the Northwest and controls a significant percentage of the transfer capacity between the Northwest and California.
- Western owns over 17,000 miles of transmission in the Western and Eastern Interconnections and is the path operator for three of the six critical qualified paths in the West.
- Fourteen of the 38 BAs in the West are non-jurisdictional.
- The non-jurisdictional transmission systems, by virtue of the manner in which they were developed as a result of 1930s legislation, surround the investor-owned utility systems and are a key to connectivity between potential market participants.

Table 3-8: Ten Largest Investor-Owned Utilities

Ten Largest Investor-Owned Utilities	State	2013 MWh
Southern California Edison	CA	83,949,877
Pacific Gas & Electric	CA	83,825,541
PacifiCorp - CA, ID, OR, UT, WA, WY	Multiple	70,617,030
Public Service Company of Colorado	CO	35,261,196
San Diego Gas & Electric	CA	34,636,840
NV Energy	NV	34,388,702
Arizona Public Service	AZ	33,642,115
Puget Sound Energy	WA	27,846,325
Portland General Electric	OR	22,950,993
Idaho Power	ID	17,460,117

Source: [EIA 2013 Form 861 Electric Data](#)

Table 3-9: Ten Largest Non-Jurisdictional Electricity Providers

Ten Largest Non-Jurisdictional Entities	State	2013 MWh	Class
Bonneville Power Administration	Multiple	86,819,182	PMA
Western Area Power Administration	Multiple	37,725,000	PMA
Salt River Project	AZ	36,382,461	Rural
Los Angeles Dept. of Water and Power	CA	22,644,848	Municipal
Tri-State Generation and Transmission	CO	19,432,244	Rural
City of Seattle	WA	9,457,191	Municipal
PUD No 1 of Chelan County	WA	4,776,963	Municipal
Pacific Northwest Generating Cooperative	OR	4,759,159	Rural
Sacramento Municipal Utility District	CA	4,553,294	Municipal
Intermountain Power Agency	CA	2,977,825	Municipal

Source: [EIA 2013 Form 861 Electric Data](#)

There are three primary types of non-jurisdictional entities, each with different governance and accountability structures:

- The PMAs are accountable to Congress, the Department of Energy, the Bureau of Reclamation, the Army Corps of Engineers, and their utility members.

- Municipal electric entities are primarily controlled by local governmental agencies.
- Rural electric associations are typically governed by their end-use customers.

Non-jurisdictional entities hold perspectives that are legitimately different from other stakeholders and there have historically been significant divides between the non-jurisdictionals, regulators, public interest groups, and (to a lesser degree) investor-owned utilities. Key fundamental differences include:

- The PMAs and other non-jurisdictional entities are not subject to the same level of state and federal jurisdiction as the investor-owned utilities. As a result, policies that influence the actions of the IOUs are generally not applicable to non-jurisdictional entities.
- The accountability structures for the non-jurisdictional entities can be much more complex and political than those of the investor-owned utilities. The non-jurisdictional constituencies frequently include a range of perspectives and can stalemate because of an inability to achieve consensus. The budgeting and rate recovery processes for the PMAs are bureaucratic and can be political.
- The PMAs can be constrained from engaging in certain types of transactions. For example, when the PMAs evaluated participation in the CAISO EIM, one of the initial concerns was their legal ability to pay the greenhouse gas emissions cost adders incorporated into the CAISO market prices. There were concerns that the adders would be considered a tax, which the PMAs are precluded by federal statute from paying. The 2014 Consolidated Appropriation Act resolved this by authorizing the PMAs to pay the *“cost of voluntary purchases of power allowances in compliance with state greenhouse gas programs existing at the time of enactment of this Act”* (emphasis added).⁸⁸ This issue could be problematic both for market participation and for EPA Clean Power Plan compliance approaches that involve emissions cost adders.
- Consistent with political party-line divisions between rural areas of the country and large cities, many (not all) of the rural electric entities are conservative and are oriented on local control. Similarly, the municipal entities are governed by variants of home rule statutes and can be averse to state or federal influence.
- The characteristics of the rural electric transmission systems differ from IOU systems because they span larger geographic distances and have lower customer densities per transmission line mile. This aspect of the system composition can be polarizing because of the potential for cost allocation inequities.
- Water issues have significant implications for the PMAs, their customers, and regional stakeholders. The West is highly dependent on water from the federal hydropower system for electricity, agriculture, commercial processes, consumer end-use, and recreation. Changing climate patterns including higher temperatures and lower precipitation increase demand for water and electricity yet decrease available resources; the growing population and higher per capita energy and water consumption put additional pressure on supplies; and complicated regimes related to water rights and environmental regulations confound the operation of the system. These factors affect the capacity, energy output, and flexibility of the hydropower generating fleet and have potentially significant implications for entities across the Interconnection.

3.4 EPA CLEAN POWER PLAN

In June of 2014, the EPA issued a proposed rule to regulate greenhouse gas emissions from existing power plants. Referred to as the Clean Power Plan (CPP), the regulations are based on Section 111(d) of the 1990 Clean Air Act and are intended to reduce CO₂ emissions from the electric sector by 30% from 2005 levels by 2030.⁸⁹

The CPP is the focus of substantive regional activity and could be a significant catalyst to the transition away from coal. When combined with previous EPA regulations that directly or indirectly affect existing generation sources, the regulations will compel the retirement of significant coal-fired capacity. For example, the 1999 Regional Haze Rule, the 2011 Cross-State Air Pollution Rule (CSAPR), and the 2012 Mercury and Air Toxics (MATS) also have significant implications for coal-fired generation. Even if there is a delay or roll-back of EPA rules, regulatory uncertainty is making ongoing investment in significant maintenance or major modifications of existing coal plants

⁸⁸ [2014 Consolidated Appropriation Act](#)

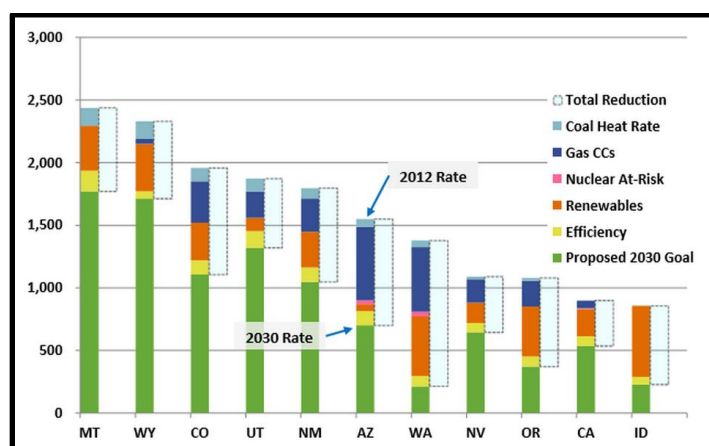
⁸⁹ For additional information on the proposed rule, please see the [Clean Power Plan section of the EPA website](#), the Regulatory Assistance Project [\(RAP\) 111\(d\) work](#), and the [WECC 111\(d\) analyses](#).

increasingly risky. This may affect the ability of entities to finance or secure approval for cost recovery of expenditures related to existing coal generation and may accelerate the retirement of the units.

The EPA has stated that it intends to release the final CPP in the summer of 2015. The current compliance timeline, which will almost certainly be revised, would require states to submit compliance plans to the EPA by the summer of 2016. Industry comments filed on the proposed rule object strenuously both to the timeline for state compliance filings and the timelines for changes to the physical infrastructure. Certain entities express concerns about the ability of utilities to achieve the targets while maintaining system reliability.

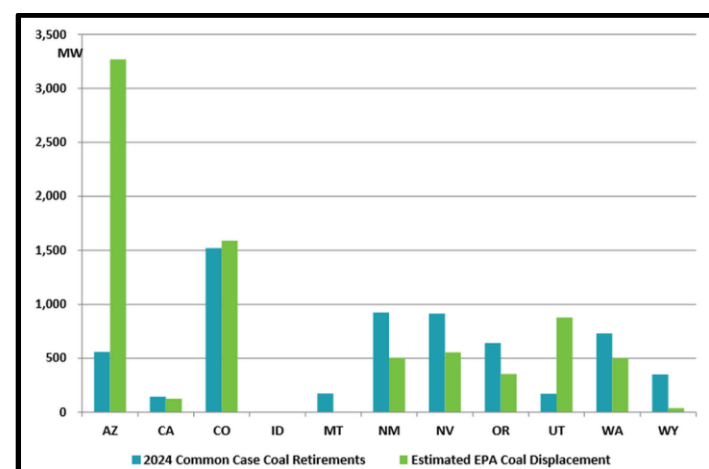
The volume of discourse in the West about the reliability implications of the CPP is remarkable considering that the region as a whole is on track to meet or exceed the CPP targets as a result of existing policies including EPA regulations and state public policy programs that include renewable energy and energy efficiency standards. The following table shows the coal retirements by state as projected by the Western Electricity Coordinating Council for 2024 (the blue columns)⁹⁰ compared to the expected EPA targets for coal retirements (the green bars.)

Figure 3-14: Clean Power Plan State Goal Breakdown (lbs/MWh)



Source: [Clean Power Plan Phase 1 Technical Report](#). WECC. September 2014.

Figure 3-15: Coal Retirements by State (2010-2024)



Source: [Clean Power Plan Phase 1 Technical Report](#). WECC. September 2014.⁹¹

⁹⁰ These values were developed by WECC with substantial input from subject matter experts. They reflect coal plant retirements that were planned prior to the EPA Clean Power Plan.

⁹¹ The WECC Transmission Expansion Planning Policy Committee (TEPPC) "Common Case" referenced in the legend is described in Section [3.6.2](#).

A key area of dissent related to the CPP is the degree to which compliance could cause system reliability issues. In November of 2014 the NERC released a report on the Potential Reliability Impacts of EPA's Proposed Clean Power Plan.⁹² The NERC report states that:

- *"State-specific carbon intensity targets create potential reliability concerns in two major areas: (1) direct impacts to resource adequacy and electric infrastructure, and (2) impacts resulting from the changing resource mix that occur as a result of replacing retiring generation, accommodating operating characteristics of new generation, integrating new technologies, and imposing greater uncertainty in demand forecasts.*
- *Most importantly, generation (along with other system resources) and transmission must provide specific capabilities to ensure the bulk power system can operate securely under a myriad of potential operating conditions and contingencies, in compliance with a wide range of NERC planning and operating Reliability Standards. The above challenges warrant further consideration by policy makers.*
- *Long lead times for transmission development and construction require long-term system planning—typically a 10–15-year outlook. In addition to designing, engineering, and contracting transmission lines, siting, permitting, and various federal, state, provincial, and municipal approvals often take much longer than five years to complete.*
- *The location of additional transmission resources will be informed by the outcome of the transmission planning studies. The transmission planning process will not be able to fully incorporate the impacts of potential retirements until those resource addition requirements are made known to the system operator."*

Stakeholders criticize the NERC analysis and industry arguments asserting potential reliability threats created by the CPP on the basis that they do not include sufficient consideration of capacity contributions and the provision of reliability services from non-traditional resources including renewable generators, other clean energy technologies, and non-generation/non-transmission alternatives. As was discussed in Section 2, although large coal-fired generating units currently provide a significant percentage of the system reliability services, clean energy technologies and gas-fired generators also have the ability to provide voltage control, reactive power, inertia, frequency response, and regulation in a manner that is portfolio based versus dependent upon one technology or a discrete number of large and aging coal generating units.

Multiple organizations have performed independent analyses and have come to the conclusion that the CPP is a flexible and feasible approach to significantly reduce GHG emissions. As one example, a February 2015 analysis by the Brattle Group concluded that:⁹³

"Following a review of the reliability concerns raised and the options for mitigating them, we find that compliance with the CPP is unlikely to materially affect reliability. The combination of the ongoing transformation of the power sector, the steps already taken by system operators, the large and expanding set of technological and operational tools available and the flexibility under the CPP are likely sufficient to ensure that compliance will not come at the cost of reliability."

WECC is analyzing the potential reliability implications of the CPP in the Western Interconnection and is developing tools to advise states as they develop their own plans and consider partnering with neighboring states for compliance.⁹⁴ WECC is collaborating with regional stakeholders including the Western Interconnection Regional Advisory Body, Western states, the National Renewable Energy Laboratory, and E3 Consulting to:⁹⁵

- *"Leverage data and analytical capabilities to assist states as they develop and evaluate compliance plans;*
- *Provide objective, regional perspective and encourage the exploration of regional/multistate compliance solutions; and*
- *Monitor and evaluate potential impacts to reliable system operations of proposed and/or potential state compliance plans."*

⁹² [Potential Reliability Impacts of EPA's Proposed Clean Power Plan – Initial Reliability Review](#). NERC. November 2014.

⁹³ The Brattle Group. [EPA's Clean Power Plan and Reliability: Assessing NERC's Initial Reliability Review](#). February 2015.

⁹⁴ Additional information about the WECC scenario analysis is available in Section [3.6](#).

⁹⁵ [WECC Board Update: EPA Clean Power Plan and WECC Efforts](#). September 2014.

In its preliminary analyses, WECC found that removing 7,000 MW of coal in the West and replacing it with non-dispatchable (i.e., wind and solar resources) results in almost no degradation in the system's ability to respond to a large contingency (i.e., the outage of a large generating unit).^{96, 97}

Similarly, the NREL Western Wind and Solar Integration Study (WWSIS), which has been underway since 2008 and is independent of the CPP work, has found that the Western Interconnection is technically capable of integrating significant percentages of wind and solar generation without negative reliability implications.⁹⁸ The Phase 3 study, released in January of 2015, evaluated renewable penetrations of up to 53% and found them to be compatible with reliable system performance.⁹⁹

In response to the significance of the CPP, FERC convened a series of technical conferences in early 2015 to address the Clean Power Plan with a focus on electric reliability, wholesale electric markets and operations, and energy infrastructure.¹⁰⁰ The technical conferences were held:¹⁰¹

- February 19, 2015 in Washington, DC
- February 25, 2015 in Denver, CO
- March 11, 2015 in Washington, DC
- March 31, 2015 in St. Louis, MO

During these technical conferences, issues related to market distortions across states and regions based on different compliance approaches were as or more prominent than discussions about reliability. The confounding market effects may necessitate the adoption of broader regional approaches which are potentially more complicated but that will likely lead to more durable outcomes than individual state compliance strategies. The FERC meetings clearly identified that there are entrenched issues related to how the system and markets currently operate that will need to be addressed. State collaboration will be essential.

In an April 2015 article in Power Magazine, FERC Commissioner Cheryl LaFleur stated that *"I believe that we as a nation can achieve real environmental progress, including on climate change, but only if we're willing to build the infrastructure—both gas and electric—and adapt the energy markets to make that possible."*¹⁰²

3.5 PEAK RELIABILITY COORDINATOR

Peak Reliability is the NERC-registered reliability coordinator (RC) for the Western Interconnection. As defined by NERC, the RC is *"The entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision."*¹⁰³

Peak is a new organization that was formed as a result of the February 2014 bifurcation of Western Electricity Coordinating Council (WECC) into a regional entity with compliance responsibilities (WECC) and a reliability

⁹⁶ [EPA Clean Power Plan Phase 1 Technical Report](#). WECC. September 2014.

⁹⁷ The WECC common case considers wind and solar to be non-dispatchable resources. This is primarily an economic versus a technical limitation and could change given appropriate market incentives to motivate asset owners to constrain energy output in favor of providing ancillary and other reliability services.

⁹⁸ [Western Wind and Solar Integration Study \(WWSIS\) web pages](#).

⁹⁹ [Western Wind and Solar Integration Phase 3 Report – Frequency Response and Transient Stability](#). National Renewable Energy Laboratory. January 2015. The 53% represents the bound of the study, not the limit of the system. Higher penetrations have not yet been evaluated.

¹⁰⁰ [FERC Supplemental Notice of Technical conferences](#). January 6, 2015.

¹⁰¹ The meeting materials are available via the FERC website: [February 19th meeting in D.C.](#); [February 25th meeting in Denver](#); [March 11th meeting in D.C.](#); [March 31st meeting in St. Louis](#).

¹⁰² Commissioner Cheryl LaFleur. [FERC's Work on the Clean Power Plan](#). Power Magazine. April 2015.

¹⁰³ [NERC Glossary](#). Updated February 2015.

coordinator (Peak). As an outcome of the 2011 Southwest outage¹⁰⁴ investigation, FERC and NERC strongly recommended that WECC bifurcate into two organizations; one to perform the NERC-designated compliance functions and a separate entity to perform the NERC-designated reliability functions. In response, WECC effectively spun off Peak to be the regional reliability coordinator. The bifurcation began in mid-2012 and culminated in February of 2014. Now in its second year of operations, Peak is in the process of defining and deploying its strategic priorities and has a number of challenges that need to be addressed.¹⁰⁵

3.5.1 Board of Directors and Member Advisory Committee

Peak Reliability is governed by a Board of Directors that is guided by a Member Advisory Committee (MAC). Peak membership includes six Classes:¹⁰⁶

Class 1: Electric Line of Business Entities owning, controlling, or operating more than one thousand (1,000) circuit miles of transmission lines of 115 kV or higher voltage within the Western Interconnection.

Class 2: Electric Line of Business Entities owning, controlling, or operating transmission or distribution lines, but not more than one thousand (1,000) circuit miles of transmission lines of 115 kV or higher voltage, within the Western Interconnection.

Class 3: Generation Owners and Operators and other Electric Line of Business Entities doing business in the Western Interconnection who are Registered Entities with NERC that do not own, control, or operate transmission or distribution lines in the Western Interconnection, including but not limited to power marketers, independent power producers, load serving entities, and any other Entity whose primary business is the provision of energy services.

Class 4: End users of significant amounts of electricity in the Western Interconnection, including industrial, agricultural, commercial, and retail entities as well as organizations in the Western Interconnection that represent the perspectives of a substantial number of persons interested in the impacts of the Bulk Electric System on the public or the environment.

Class 5: State and Provincial Representatives from the Western Interconnection having policy or regulatory roles and who do not represent state or provincial agencies and departments whose function involves significant direct participation in the market as an end user or in Electric Line of Business activities.

Class 6: Members at large, that is, entities that are not otherwise eligible for Membership in the other Member Classes but who have a substantial interest in the purposes of Peak Reliability, such as developers.

3.5.2 Alternative Funding

Peak's funding, which was initially an allocation of the Federal Power Act Section 215 assessments, was challenged by the Edison Electric Institute and the Peak Class 1 and Class 2 members. As a result, the funding source is in the process of shifting from Section 215 funding to bilateral contracts between Peak and its transmission owner/operator members. Funding has been a source of contention since the initiation of the WECC bifurcation. During the bifurcation, FERC ruled in favor of Section 215 funding for Peak and subsequently affirmed the ruling upon rehearing. Edison Electric Institute appealed to the DC Court of Appeals in May of 2014. Before the DC Circuit Court heard the case, FERC requested that it be remanded back to FERC for further consideration. The docket has not been acted upon since the remand. In the meantime, Peak Class 1 and Class 2 members developed an Alternative Funding Mechanism under which funding for Peak will be directly from the members. A draft agreement that reflects the results of the negotiations was issued on April 10, 2015 and was approved by the Peak Board on May 11, 2015. It is expected that the membership will approve the agreement.¹⁰⁷

¹⁰⁴ On September 8, 2011 the loss of a single transmission line in Arizona initiated a cascading electricity outage that affected parts of Arizona, Southern California, and Baja Mexico. The outage left approximately 5 million people without power for up to 12 hours. A [joint analysis](#) performed by the Federal Energy Regulatory Commission (FERC) and the North American Electric Reliability Corporation (NERC) determined that inadequate planning and deficiencies in real-time situational awareness were primary contributors to the outage.

¹⁰⁵ The Peak Reliability 2015-2019 Strategic Plan was finalized in January of 2015 and is available [here](#).

¹⁰⁶ [Peak Reliability website](#).

¹⁰⁷ [Peak Reliability Alternative Funding Agreement Web-Pages](#).

3.5.3 Data Sharing

Data sharing has been a topic of debate since the beginning of the bifurcation effort. Peak, in its normal course of operations, receives and has the right to request extensive operating data. Prior to the bifurcation, WECC had access to the data and the organization used it both for operational and system planning purposes. The data is essential for WECC's Transmission Expansion Planning and Policy Committee (TEPPC) (discussed in Section [3.6.2](#)) and for its regional reliability analyses. In addition to WECC's need for the data, transmission planners, developers, independent researchers, and industry stakeholders require the data to perform objective operational, reliability, and planning analyses.

A joint Peak-WECC data sharing task force, which has significant industry participation, engaged in a process to develop a broadly acceptable data sharing agreement but came to an impasse. Operating entities are highly resistant to the dissemination of the data, including to WECC, and cite both critical infrastructure protection and commercial confidentiality concerns related to its release. Non-utility stakeholders argue that without access to the system infrastructure and operating data, which has historically been available subject to limitations, WECC will be unable to perform its statutory responsibilities and regional stakeholders will be stymied in their objective analysis of the system. At the direction of the Board, Peak staff developed a data sharing policy to replace the legacy data sharing agreement. This was supported by non-utility members of Peak and other stakeholders but met heavy resistance from the utilities. At its March 18th meeting, the Peak Board of Directors deployed a short-term solution by approving an interim bridge policy that extends the current data sharing practices with some modifications for an additional year. The Board's goal is to have a new data sharing agreement ready for approval in December.

3.5.4 Enhanced Curtailment Calculator (ECC)

From a task perspective, Peak is not moving projects forward at a pace that is perceived by some stakeholders to be sufficiently expeditious. Two projects of specific concern are the Enhanced Curtailment Calculator (ECC) (Section [3.5.4](#)) and the Western Interconnection Synchrophasor Project (WISP) (Section [3.5.5](#)). Both the ECC and the WISP are integral to the ability of the Interconnection to advance the situational awareness and control necessary to support reliability and clean energy integration yet both are mired in institutional inertia. Peak has other important projects underway, but these have the potential to be particularly problematic.

The ECC is a situational awareness and control tool that is intended to enable enhanced regional management of transmission congestion and reliability. Additionally, the ECC is intended to improve financial equity by curtailing transmission in better alignment with priority rights than what is facilitated by the tools and processes that are currently in place. The ECC is intended to be a substantial improvement over the current tool, WebSAS, and is important for the success of the EIM, the NWPP MC, and other regional initiatives. The highly technical nature of the project has kept stakeholder engagement relatively constrained, but the development is approaching a point where a broader set of industry participants will need to become involved.

Although the ECC is intended to significantly enhance reliability management, it is contentious. The ECC deployment is targeted to occur in two phases:

- Phase 1: Develop the functional specifications and software. Integrate it into the Peak control center operations. Peak is working with regional stakeholders and a software vendor, OATI, to develop the ECC functionalities. The purpose of the tool will be to optimize congestion relief in alignment with transmission priorities. In Phase 1, Peak would not have the ability to physically curtail the system.
- Phase 2: Expand the ECC to provide Peak with physical control of the system.

System operators are highly opposed to Phase 2, which is possibly a driving factor in the slow progress of Phase 1. Peak does not currently have physical control over any aspect of the system. It manages transmission congestion by issuing manual instructions and directives to BAs and transmission operators. Phase 2 of the ECC is a complete paradigm shift and is expected to be exceptionally complicated and difficult from both operational and stakeholder engagement perspectives.

Some regional entities assert that the tool is essential as a means to protect reliability and to ensure equitable curtailments in accordance with transmission rights. Others argue that Peak does not have sufficient information or expertise about the transmission infrastructure to reasonably have physical control of the system, and that automation of curtailments would create significant reliability risks. Peak's response is that system operators need to provide the currently un-modeled constraints, to which the operators respond that the expertise is not portable to an optimization model. This circular discussion has been in process since the 2011/2012 development of the ECC task force.

RTOs across the country have physical curtailment abilities integrated into system operations and are able to effectively manage curtailments without endangering reliability. A key difference in the RTO regions is that transmission cost recovery is based on a regional rollup of costs, and actions that affect a particular path within the larger system do not have the same level of equity considerations. The challenges related to the balkanization of the Western Interconnection and the inherent impracticalities of contract-path transmission rights are glaringly evident in the ECC debate.

3.5.5 Western Interconnection Synchrophasor Program (WISP)

An example of a significant investment that is underway to improve situational awareness and control is the Western Interconnection Synchrophasor Program (WISP).^{108, 109} The WISP was initiated in 2009 to develop synchrophasor infrastructure in the Interconnection and has since received \$115.6 million in funding via DOE matching grants and contributions from regional entities.¹¹⁰ E3 Consulting performed an analysis of the potential benefits and estimated that the WISP could result in operational and economic benefits of \$1.8 billion over a 40 year period. Of these benefits, \$630 million were projected to be associated with increased utilization of and decreased capacity costs for renewables.¹¹¹

Within the expansive scope and scale of electricity system operations, situational awareness and control are conditions precedent to making meaningful advancements in system performance, yet there are significant deficiencies in these areas in the West. As a result of the deficiencies, system operators need to be prepared to address unexpected power flows and system disturbances with tools that may not be optimal. This can result in minor to significant operational challenges across the Interconnection and can also result in the system being operated in an unduly conservative and uneconomic manner.

Integrated and real-time information on forecast and actual generation and load, unscheduled power flows, frequency excursions, and voltage deviations is critical. As penetrations of clean energy resources increase in the West, situational awareness and control will become increasingly paramount. The WISP has the potential to provide significant value in this area.

The Peak website indicated in October of 2014 that full deployment of the WISP is expected to:¹¹²

- Help defer investment in transmission capacity expansions.
- Reduce ancillary service cost.
- Reduce wide-scale blackouts.

¹⁰⁸ WECC. [WISP Project FAQs](#). December 2009.

¹⁰⁹ Synchrophasors are a key tool to enable situational awareness. The [North American Synchrophasor Initiative Fact Sheet](#) states that "Synchrophasors are precise electrical grid measurements of values such as voltage or power that are available from monitors called Phasor Measurement Units (PMUs). These measurements are taken at high speed (30 observations per second), and each measurement is time-stamped according to a common time reference. Time stamping allows synchrophasors from different utilities to be time-aligned (or synchronized) and combined together, providing a detailed and internally consistent operational "picture" of the entire Interconnection. This picture can help grid operators detect disturbances that would have been impossible to see with older supervisory control and data acquisition (SCADA) systems, which typically collect one measurement every 2-4 seconds."

¹¹⁰ Funding and hosting entities include BPA, Idaho Power, NV Energy, PacifiCorp, Peak Reliability, Pacific Gas and Electric, Southern California Edison, San Diego Gas and Electric, Salt River Project, WECC, and a collaboration between CAISO, the California Energy Commission, and the Electric Power Research Institute. The WISP program involves the full Interconnection.

¹¹¹ WECC. [WISP Project FAQs](#). December 2009.

¹¹² Peak Reliability. [What We Do](#). Website accessed October 31, 2014.

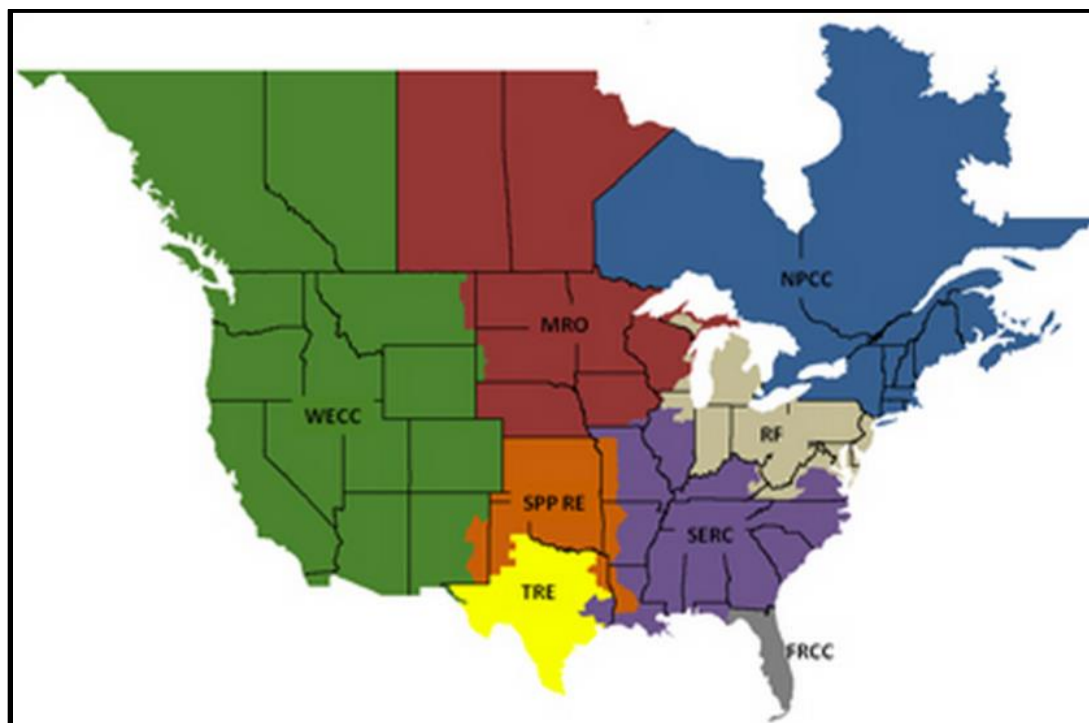
- Increase electric service reliability.
- Improve utilization of intermittent renewable generation.

In the joint 2011 Southwest outage analysis, FERC and NERC noted that the WISP tools were not sufficiently integrated to be used during the event, but that the data proved to be valuable in the forensic analysis.¹¹³ It is not clear from publicly available information when the WISP will be fully functional.

3.6 WESTERN ELECTRICITY COORDINATING COUNCIL (WECC)

WECC is one of eight entities designated by NERC to manage the reliability of the bulk power system. WECC's statutory responsibilities are to develop and enforce reliability standards within its geographic boundaries; certify and register owners, operators, and users of the bulk power system as responsible for compliance with reliability standards; perform reliability assessments and performance analyses; analyze system events and reliability improvements; provide training and education to registered entities; and assess situational awareness and infrastructure security.¹¹⁴

Figure 3-16: NERC Reliability Regions



Source: [NERC](#)

WECC, like Peak, is funded by allocations of Federal Power Act Section 215 assessments. Unlike Peak, WECC's status as a 215-funded entity is relatively secure. However, there is pressure by utilities to constrain this funding to cover only the standards and compliance functions of the organization. Non-utility stakeholders favor a broader role for WECC and press the organization to be forward looking and to perform extensive analysis to evaluate reliability in a dynamic future.

¹¹³ FERC and NERC joint report: [Arizona-Southern California Outages on September 8, 2011: Causes and Recommendations](#). April 2012. Pages 85 and 86.

¹¹⁴ [Amended and Restated Delegation Agreement between NERC and WECC](#). December 2014.

3.6.1 Board of Directors and Member Advisory Committee

The WECC Board and Member Advisory Committee (MAC) are tasked with maintaining alignment with the organization's strategic objectives. The WECC has five member Classes:¹¹⁵

Class 1: Electric Line of Business Entities owning, controlling or operating more than 1,000 circuit miles of transmission lines of 115 kV and higher voltages within the Western Interconnection.

Class 2: Electric Line of Business Entities owning, controlling or operating transmission or distribution lines, but not more than 1,000 circuit miles of transmission lines of 115 kV or greater, within the Western Interconnection.

Class 3: Electric Line of Business Entities doing business in the Western Interconnection that do not own, control or operate transmission or distribution lines in the Western Interconnection, including power marketers, independent power producers, load serving entities, any other Entities whose primary business is the provision of energy services, and those Entities that are not eligible for membership in the other Member Classes and who have a substantial interest in the purposes of WECC.

Class 4: End users of significant amounts of electricity in the Western Interconnection, including industrial, agricultural, commercial and retail entities as well as organizations in the Western Interconnection that represent the interests of a substantial number of end users or a substantial number of persons interested in the impacts of electric systems on the public or the environment.

Class 5: Representatives of states and provinces in the Western Interconnection, provided that such representatives will have policy or regulatory roles and do not represent state or provincial agencies and departments whose function involves significant direct participation in the market as end users or in Electric Line of Business activities.

3.6.2 Transmission Planning and System Assessment Committees, Task Forces, and Working Groups

The WECC has a myriad of committees, task forces, and working groups, a number of which are focused on optimization of transmission planning and development.¹¹⁶ These include but are not limited to the Transmission Expansion Planning Policy Committee (TEPPC), the Scenario Planning Steering Group (SPSG), the Environmental Data Task Force (EDTF), and the Metrics Definition Task Force (MDTF).

Individually and collectively these committees, task forces, and working groups generate publicly available information developed by key subject matter experts in the Interconnection. Industry stakeholders are able to support and guide regional transmission development by collaborating to create consensus-driven base cases (also referred to as common cases) and scenario analyses that are used by the planning regions, developers, researchers, and multiple other industry stakeholders. The existence of centralized databases and analyses constructed from viable sources with well-vetted assumptions is essential to reduce general information asymmetry, support regional transmission planning, and provide independent transmission and generation developers with access to information they need to formulate competitive capacity expansion proposals.¹¹⁷

The committees seek to ensure broad stakeholder involvement through communication and outreach activities such as monthly regional conference calls and topical workshops. Key work products include:

- Centralized databases of generation and transmission characteristics to a very granular level of detail. These resources are used by WECC and the industry and are also invaluable for developers, the national laboratories, consultants, and other independent stakeholders.
- Forums for subject matter experts to shape basic assumptions including but not limited to coal and gas fuel cost projections, thermal unit retirements, current and future renewable energy capital costs and equipment

¹¹⁵ [WECC Bylaws](#). Accessed February 2015.

¹¹⁶ As of the date of this report, there are 70 different committees, task forces, and working groups within WECC. This proliferation is a target for criticism because it can be perceived that there is significant overlap between the committee members and topics. The work structures are a focus area for a WECC Section 4.9 review that seeks to evaluate and optimize the performance of the WECC. The Section 4.9 Task Force Work Plan as approved in November of 2014 is available [here](#).

¹¹⁷ Many, but not all, of the databases and analyses are public.

capabilities, expected expansions of centralized and distributed renewable energy, and increases or decreases in demand.

- Scenario analyses that iteratively evaluate various potential futures of transmission development; centralized and distributed renewable energy deployment; and coal retirements. These analyses inform flexibility assessments and EPA Clean Power Plan study efforts.
- The development and ongoing population of land use databases to guide developers towards potential transmission routing that will be the least problematic in terms crossing environmentally sensitive areas, tribal lands, restricted access federal and state property, or otherwise protected areas of the region. This work is expected to take decades off of transmission development timelines.

The expertise and public resources developed by the WECC committees are essential to transmission and generation development in the West yet are the target of relatively frequent challenges by the industry. Policy makers and industry stakeholders will need to continue to be vigilant about protecting the data and analytic resources provided by WECC.

3.6.3 System Flexibility Assessment

WECC is performing a system flexibility assessment that incorporates progressive assumptions about renewable energy development and coal plant retirements. The incumbent infrastructure and operational constraints in the West have created a largely inflexible system that is poorly positioned to adapt to a dynamic future. Flexible resource sufficiency is a growing area of interest and is expected to increase in operational and regulatory significance across multiple states in the near to mid-term.

Flexible resources:

- Are responsive to system operating signals.
- Can rapidly increase or decrease output (i.e., ramp up or down).
- Are capable of sustaining ramps for minutes to hours.
- Have low minimum operating levels.
- Are quick start, quick stop.

Flexible technologies include:

- Gas-fired combined cycle, single cycle, and internal combustion generators.
- Active power controls on wind turbines (e.g., automatic generation control, frequency response, and synthetic inertia).
- Advanced wind and solar inverters.
- Storage.
- Demand response.

As a result of the criticality of the flexibility issue, WECC and the Western Interstate Energy Board have initiated a flexibility analysis project. The entities are *“working together to pursue a joint project to examine the reliability and flexibility of the Western Interconnection ten years in the future. The purpose of this joint project is to study power system reliability and flexibility in the Western Interconnection for use in WECC’s current Transmission Expansion Planning study cycle. Through a series of regional studies, using regional capacity adequacy analysis and flexibility analysis, the work will:*

- *Assess the adequacy of the fleet of resources in the Western Interconnection to meet loads throughout the year with acceptable reliability;*
- *Assess the ability of the fleet of resources in the Western Interconnection to accommodate high penetrations of variable renewable energy resources while maintaining reliable operations;*
- *Investigate operational challenges, potential constraints on flexible operations, and potential solutions to those challenges at high levels of renewable penetration in the Western Interconnection;*
- *Characterize the size, magnitude and duration of any flexibility deficiencies that might result in reliability challenges under one or more plausible high renewable cases;*
- *Assess the extent to which transmission and regional coordination can provide assistance in meeting flexibility needs;*

- Investigate potential flexibility solutions, including but not limited to flexible fossil generation, demand-side resources, energy storage, CAES and pumped hydro; and
- Explore and demonstrate the use of a flexibility planning framework and modeling tool at the Interconnection level.¹¹⁸

The WECC and the Western Interstate Energy Board work in this area is intended to provide credible and independent analysis of the ability of the Interconnection to reliably shift the generation profile and adapt to a future that includes significant coal capacity reductions and renewable resource expansions.

3.7 DEPARTMENT OF ENERGY

The Department of Energy (DOE) is critical to the ability of entities in the Interconnection to evaluate, fund, and deploy strategies and technologies to advance the reliability and economic performance of the BES. The DOE oversees the national labs, which perform important analytics on system operations and clean energy integration. The Department is a channel for funding from the federal government to regional groups that convene policy forums and develop both qualitative and quantitative policy and technical analyses.

DOE activities of particular interest include:

- The Quadrennial Energy Review (QER) was initiated as a result of a Presidential directive and is intended to evaluate energy infrastructure and government-wide energy policy in order to provide guidance for federal activity in these areas. The DOE is tasked with the development of the review and the first report on the transmission, storage, and distribution of electricity was released in April of 2015. The level of action that will be taken as a result of the analysis is not yet clear.
- The Quadrennial Technology Review is underway to “identify the important technology research development, deployment, and diffusion opportunities across energy supply and end-use in working towards a clean energy economy in the United States. The insight gained from this analysis will provide essential information for decision-makers as they develop funding decisions, approaches to public-private partnerships, and other strategic actions over the next five years.” Both the QER and the QTR could be instrumental in guiding federal activity and investment that is in alignment with priorities in the West.
- The Transmission Infrastructure Program (TIP), under the purview of the Western Area Power Administration, has \$3.25 billion in borrowing authority to “facilitate the delivery to market of power generated by renewable energy resources.” The program is generally considered to be under-utilized due to lack of qualified projects and was repositioned in May of 2014 in a manner that could enable Western to work more proactively with potential developers on project proposals that could be candidates for TIP support.
- The Western Interconnection Synchrophasor Program (WISP),¹¹⁹ funded in part by DOE matching grants, is a promising endeavor that doesn’t seem to have broad industry participation and would likely benefit from additional DOE and stakeholder engagement. This program is important for other regional activities.
- The DOE Grid Modernization Laboratory Consortium was launched in November of 2014 and is intended to be “a strategic partnership between DOE headquarters and our National Laboratories to bring together our leading experts and resources to collaborate on the goal of modernizing the nation’s grid.” One of the objectives of the Consortium “will be to develop a multi-year program plan for grid modernization. The plan will outline an integrated systems approach to transforming the nation’s grid by incorporating numerous program activities within DOE as well as activities undertaken by national stakeholders.” These activities will ideally include the Transactive Energy efforts of Pacific Northwest National Laboratory’s GridWise Architecture Council which evaluates “techniques for managing the generation, consumption or flow of electric power within an electric power system through the use of economic or market based constructs while considering grid reliability constraints.”¹²⁰

¹¹⁸ Source: Western Interstate Energy Board.

¹¹⁹ Discussion of the WISP is provided in Section 3.5.5.

¹²⁰ Please see the GridWise Architecture Council discussion of transactive energy available [here](#).

3.8 CONCLUDING OBSERVATIONS

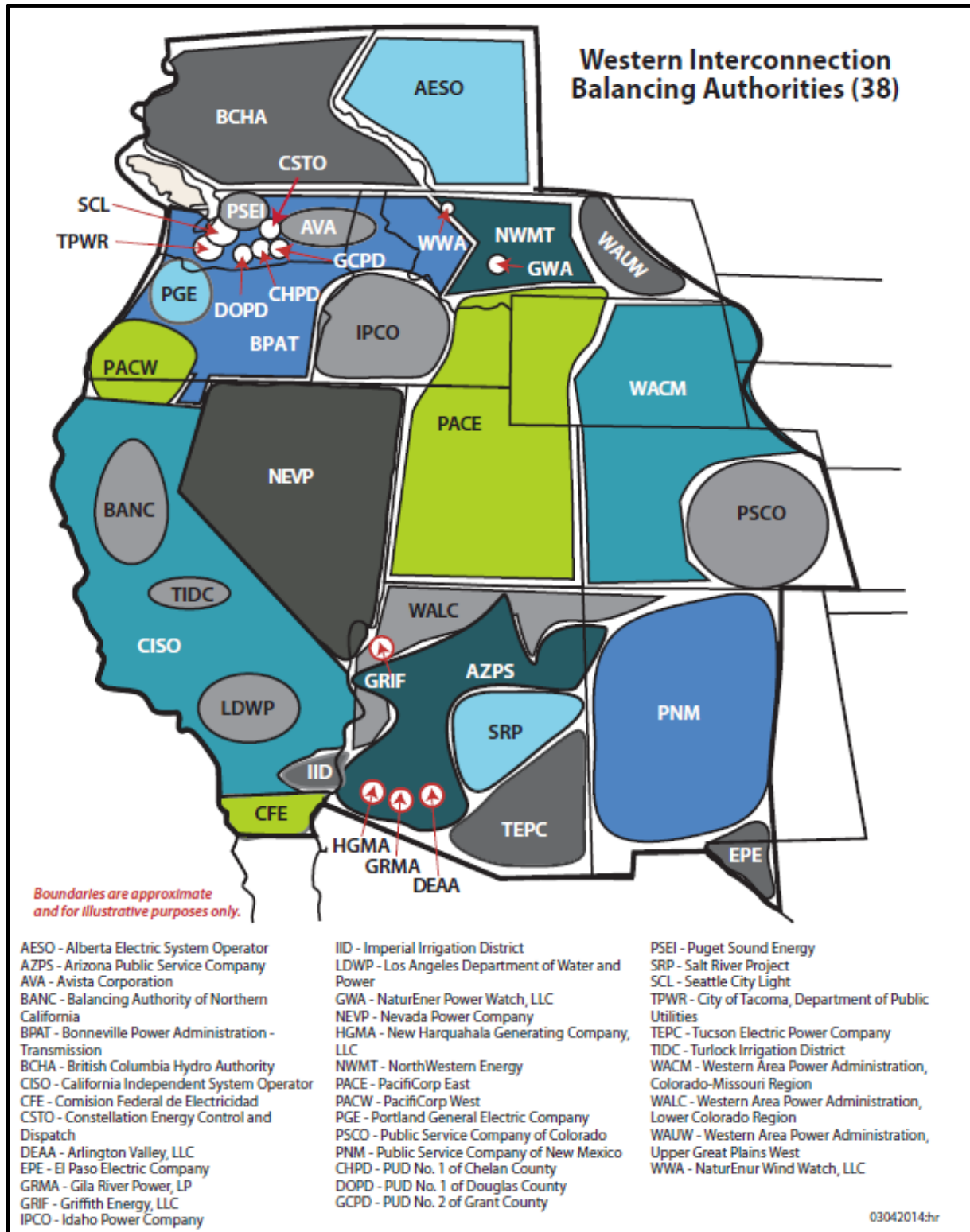
As the industry moves forward, policy makers and other stakeholders will be well-served to stay abreast of the myriad of regional activities with an eye towards requiring that the initiatives protect both reliability and ratepayers. To this end, ongoing analysis, outreach, and informational updates will be necessary to break through the walls of conjecture about the ability of the system to evolve to more fully align with public policy priorities.

Specific examples of analytics that will be important for policy makers include:

- More complete understanding of the reliability benefits of regional collaborations with a focus on providing material targeted for state regulators. Demonstrate that regional coordination aids reliability and that lack of it creates substantive and growing reliability threats.
- Case studies of how the Southwest Power Pool and the Midcontinent Independent System Operator navigated their transitions from multi-BA operations to RTOs to fully integrated forward markets. With the Southwest Power Pool, it may be particularly compelling to evaluate the manner in which the organization addressed the priorities of the multiple states and non-jurisdictional entities in its service territory.
- Evaluations of lessons learned and best practices on the ability of RTOs to optimize clean energy resource integration. There are conceptual analyses of why regional operations and markets are good for integration, but quantitative and qualitative assessments are needed of where this is working well in the Eastern Interconnection and Texas.
- Robust economic valuations about the cost of outages to as much regional detail as possible. This will aid both state and federal decision and investment making processes.
- Analysis of the means by which markets can support the retention of valuable assets, the unlocking of technical potential from existing resources, and investment in new technologies (e.g., advanced inverters and active power controls).
- Qualitative and quantitative analyses on the inter-relationships between EPA compliance options, markets, and multi-lateral operating agreements. Identification of the implications of various compliance approaches.

In order to successfully implement currently enacted and emerging clean energy policies, regional and state policy makers will increasingly be called upon to understand and make decisions about complex regional planning, operating, and market issues that have not historically been at the forefront of regulatory activities in the West. This will require a dramatically increased level of coordination between state and regional entities and will be a paradigm shift for the West; the success or failure of which will determine the ability of the Interconnection to transition the electricity system.

Appendix A – Western Interconnection Balancing Authorities



Source: Western Electricity Coordinating Council

Appendix B – Acronyms

APS	Arizona Public Service
ARRA	American Recovery and Reinvestment Act of 2009
BA	Balancing Authority
BAA	Balancing Authority Area
BES	Bulk Electric System
BPA	Bonneville Power Administration
CAISO	California Independent System Operator
CPP	EPA 111(d) Clean Power Plan
DOE	Department of Energy
DSTF	Data Sharing Task Force
ECC	Enhanced Curtailment Calculator
EDTF	Environmental Data Task Force
EIM	Energy Imbalance Market
FERC	Federal Energy Regulatory Commission
IOU	Investor Owned Utility
ISO	Independent System Operator
LBNL	Lawrence Berkeley National Laboratory
MAC	Member Advisory Committee
MC	Northwest Power Pool Market Assessment and Coordination Committee
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
NTTG	Northern Tier Transmission Group
NWPP MC	Northwest Power Pool Market Assessment and Coordination Committee
PMA	Power Marketing Administration
PMC	Planning Management Committee
PNM	Public Service Company of New Mexico
PPA	Planning Participation Agreement
PRPA	Platte River Power Authority
PSCO	Public Service Company of Colorado
PUC	Public Utility Commission
RFP	Request for Proposal
RTO	Regional Transmission Organization
SCED	Security Constrained Economic Dispatch
SPP	Southwest Power Pool
SRP	Salt River Project
SVERI	Southwest Variable Energy Resources Initiative
TEPPC	Transmission Expansion Planning Policy Committee
TIP	DOE/Western Area Power Administration Transmission Infrastructure Program
WECC	Western Electricity Coordinating Council
WIEB	Western Interstate Energy Board
WIRAB	Western Interconnection Regional Advisory Body
WISP	Western Interconnection Synchrophasor Project