PREPARED FOR:
Colorado Governor's Energy Office

Renewable Energy Development Infrastructure (REDI) Project

Regulatory and Economic Analysis

Funded by: U.S. Department of Energy
and Colorado Governor's Energy Office

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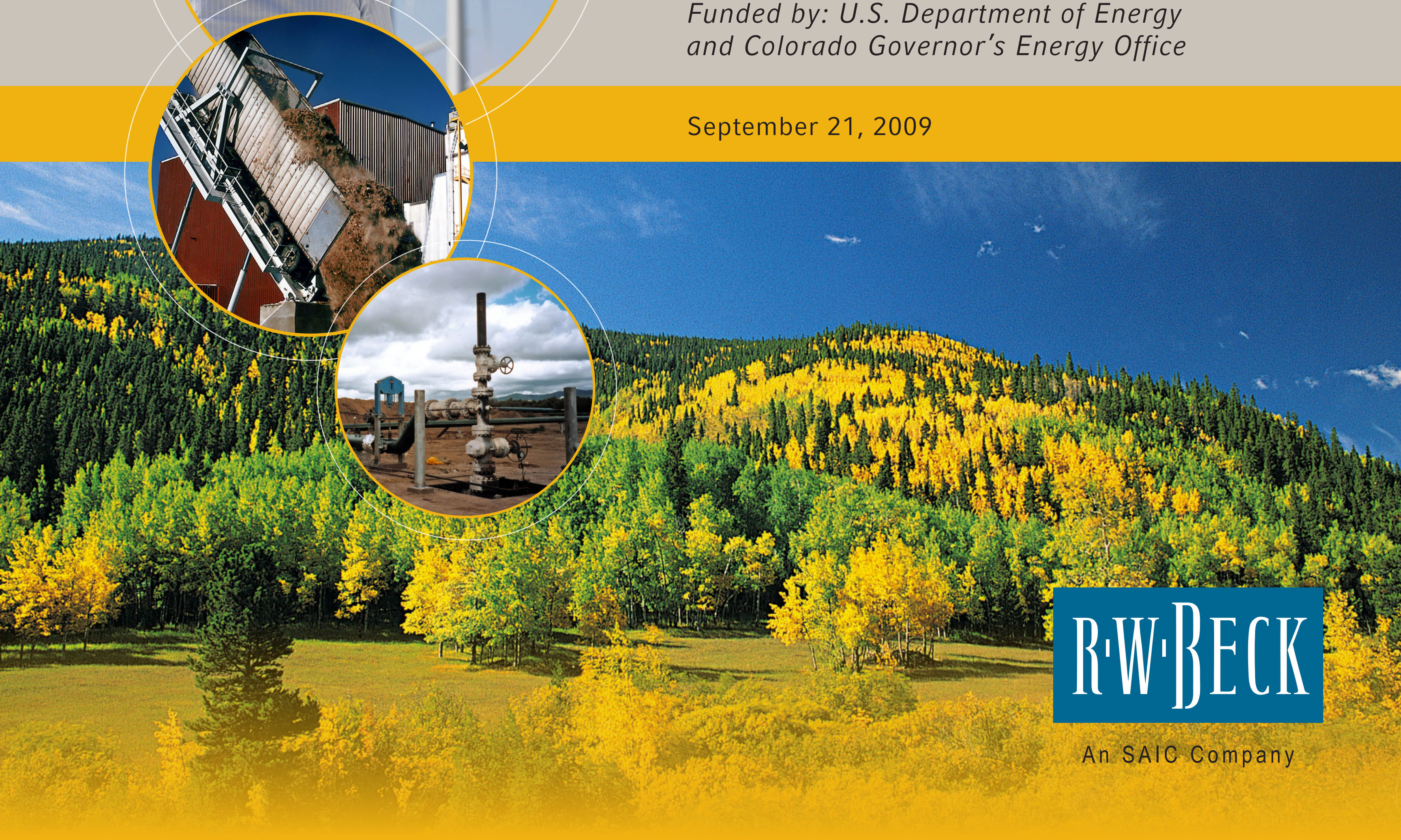

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The Colorado Governor's Energy Office (GEO) engaged R. W. Beck, Inc. (R. W. Beck), an SAIC company, to participate in the Renewable Energy Development Infrastructure (REDI) project. The REDI project was funded by GEO through a grant from the United States Department of Energy's (DOE) Office of Electricity Delivery and Energy Reliability. R. W. Beck was asked to provide an overview of the regulatory and economic aspects of the transmission development needed to provide access to Colorado's significant renewable resources as identified in the Colorado's Senate Bill 07-091 Report on the Renewable Resource Generation Development Areas (GDA). The focus of the REDI project is on activities that would encourage the development of high voltage transmission in Colorado and advance Colorado's New Energy Economy.

Morey Wolfson, GEO Transmission Program Manager, acted as the REDI project Principal Investigator. Matthew Brown of ConoverBrown was the REDI Project Manager. Skeeter Buck provided administrative assistance to the REDI project.

Bahman Daryanian served as the R. W. Beck project manager and principal investigator of R. W. Beck's portion of the REDI project. Other principal contributors from R. W. Beck included Donna Painter and Patrick Brin. The project also drew, as needed, on the collective knowledge and experience of other experts within R. W. Beck. Donna Brannan, Susan McDermid, and Kenna Norton provided editorial and report production support.

In addition to R. W. Beck, the other REDI Project Team members included:

- The National Renewable Energy Laboratory
- The University of Colorado-Denver Civil Engineering Department
- Navarro Engineering
- WorleyParsons
- ConoverBrown

The REDI Project Team worked with an Advisory Board that GEO assembled. The Advisory Board members who provided assistance to this projected were:

- Eugene Camp, representing the Staff of the Colorado Public Utilities Commission
- Craig Cox, representing Interwest Energy Alliance
- Tom Darin, representing Western Resource Advocates
- Rick Gilliam, representing SunEdison
- Ethnie Groves, representing Xcel Energy
- Ron Lehr, representing the American Wind Energy Association
- Dill Ramsay and Ron Steinbach, representing Tri-State Generation and Transmission Association
- Lee White, representing the Colorado Clean Energy Development Authority

Instead of being regarded as a stand-alone report, this Regulatory and Economic Analysis (this report) should be viewed as a compendium of subjects and issues that were assigned to R. W. Beck. R. W. Beck provided the background material to the REDI principal investigator, project manager, and other team members, for the development of the final consolidated report, which would also include contributions from other project consultants.

The early sections of this report present a broad picture of the electricity market and the renewable energy and transmission development status in Colorado. Other sections provide descriptions of the regional transmission planning processes, interaction of various state and regional entities, and federal and state regulatory processes for addressing cost recovery.

R. W. Beck's consultants hereby acknowledge the original contribution of various sources without which this work would not have been possible. R. W. Beck's consultants also wish to thank many individuals, stakeholder representatives, the REDI Project Team, and the REDI Advisory Board, who made significant contributions to our understanding of the issues.

Most of the information contained in this report is based on publicly available sources and documents. Additional information was collected through interviews with a number of stakeholders in the electric power sector of Colorado. For expository descriptions, heavy reliance was made on sources believed to be reliable, including work done by other practitioners. A good faith effort was made to reference all the relevant sources in the footnotes. Unless noted otherwise, all figures contained in this report were created by R. W. Beck using Ventyx's "Velocity Suite" software. Any error in reporting, quoting, referencing, or attributing of the original sources is inadvertent.

For the most part, this work is a survey of the current status of the development of transmission infrastructure for renewable energy resources in Colorado and the region. Given the continuous remaking of the regulatory and financial landscape in the United States (US) power industry, this report can only provide a broad picture of the state of affairs, without claiming to be complete and exhaustive in its coverage. Any implied recommendations offered in this report are intended to motivate discussion by policy makers and stakeholders, and are not meant to provide a definitive course of action without further economic, policy, and regulatory evaluation.

R. W. Beck, an SAIC company, is a group of technically based business consultants serving public and private infrastructure organizations and financiers in the energy, water, wastewater, and solid waste industries. R. W. Beck develops sustainable solutions specific to clients' engineering, economic, financial, planning, operational, and organizational challenges. R. W. Beck integrates business and financial acumen with technical expertise to drive success for clients and their stakeholders.

Any comments and reporting of errors or omissions in presentation and attributions/references may be sent to Bahman Daryanian at bdaryanian@rwbeck.com.

AC	Alternative Current
ATC	Available Transmission Capability
CAISO	California Independent System Operator
CCPG	Colorado Coordinated Planning Group
CEDA	Colorado Clean Energy Development Authority
Commission	Federal Energy Regulatory Commission
Co-ops	Rural Electric Cooperatives
CPCN	Certificate of Public Convenience and Necessity
CWIP	Construction Work In Progress
DC	Direct Current
DOE	United Stated Department of Energy
DSIRE	Database of State Incentives for Renewables and Efficiency
EPAct 2005	Energy Policy Act of 2005
ERO	Electric Reliability Organization
FERC	Federal Energy Regulatory Commission
GDA	Generation Development Areas
GEO	Governor's Energy Office
HB	House Bill
ISO	Independent System Operator
ISO-NE	ISO New England
kV	kilovolt
kWh	kilowatt hour
IOUs	investor-owned utilities
MISO	Midwest ISO
Munis	Municipal Utilities
MW	Megawatt
MWh	Megawatt hour
NEPA	National Environmental Policy Act
NERC	North American Reliability Corporation
OASIS	Open Access Same-Time Information System
OATT	Open Access Transmission Tariff
PJM	PJM Interconnection

PSCo	Public Service Company of Colorado
PUC	Public Utilities Commission
REA	Rural Electric Association
REC	renewable energy credits or certificates
REDI	Renewable Energy Development Infrastructure
REZ	Renewable Energy Zones
RETA	New Mexico Renewable Energy Transmission Authority
RMPA	Rocky Mountain Power Area
RMATS	Rocky Mountain Area Transmission Study
RPS	Renewable Portfolio Standards
RTO	Regional Transmission Organization
SB	Senate Bill
SDEIA	South Dakota Energy Infrastructure Authority
SPP	Southwest Power Pool
STP Agreement	WestConnect Project Agreement for Sub-regional Transmission Planning
SWAT	Southwest Transmission Planning Group
TEPPC	WECC's Transmission Expansion Policy and Planning Committee
TOTs	TOTal power flows, as shown in Figure 2-28
Tri-State	Tri-State Generation and Transmission Administration
US	United States
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council
WestConnect	Planning organization in Rocky Mountain and Southwest regions
wesTTrans	An enhanced OASIS site serving a significant portion of the WECC
WGA	Western Governors' Association
WIA	Wyoming Infrastructure Authority
WREGIS	Western Renewable Energy Generation Information System
WREZ	Western Renewable Energy Zones

1.1 Renewable Portfolio Standards in Colorado

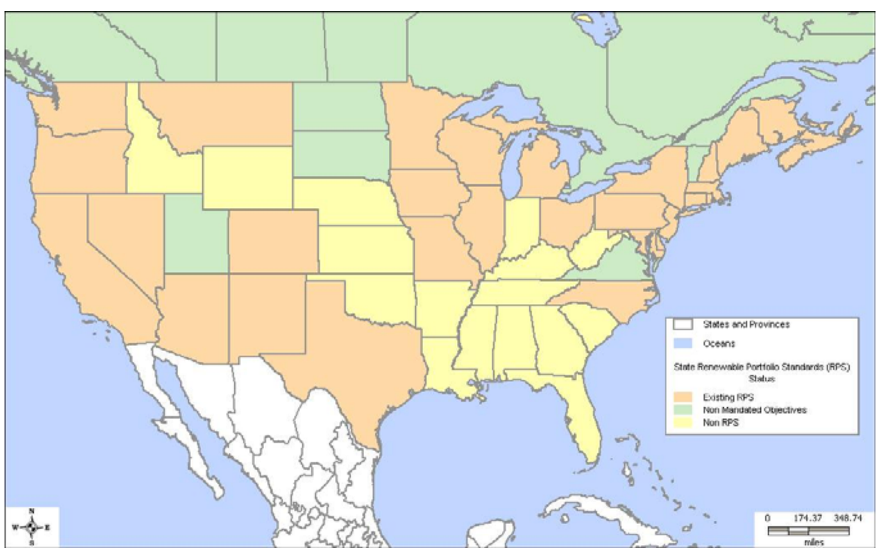
1.1.1 Renewable Portfolio Standards

A Renewable Portfolio Standard (RPS) is a state policy or regulation that requires electricity providers to provide a specified minimum amount or percentage of its power for customer load from eligible renewable energy resources by a target date. The goal of an RPS is to promote development of renewable energy resources because of the environmental and sustainability features of such resources.

RPS-type legislation has been adopted by many state legislatures. There is currently no federal RPS policy, although a future federal RPS legislation setting a national renewable energy requirement is a possibility.

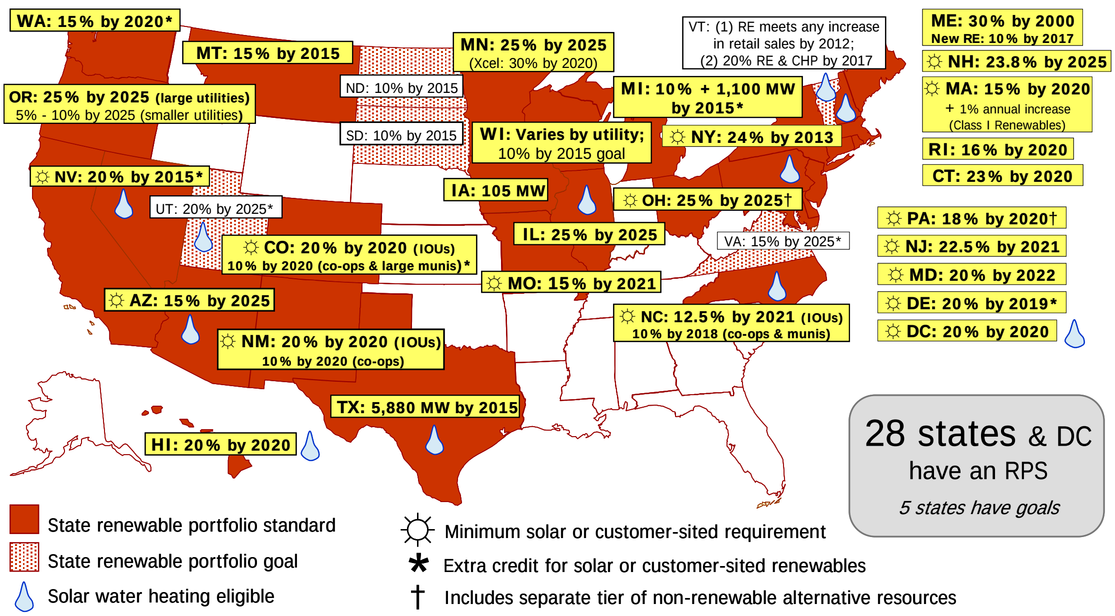
In this report, "RPS" is used as a generic term to refer to the state renewable energy regulations, but some states refer to their policies by other names. Not all states have RPS, but the number of those with a RPS, in its different forms, is increasing. Most of the states with a RPS have mandatory policies while a few rely on voluntary actions. Figure 1-1 presents the state-by-state status of RPS programs in the US.

Figure 1-1. Status of Renewable Portfolio Standard Regulation in the US



RPS regulations vary from state to state in their definition of RPS targets, target levels, and schedules, types of utilities subject to regulation, and the set of eligible renewable resources. Figure 1-2 provides a high-level summary of state RPS targets as of April 2009.

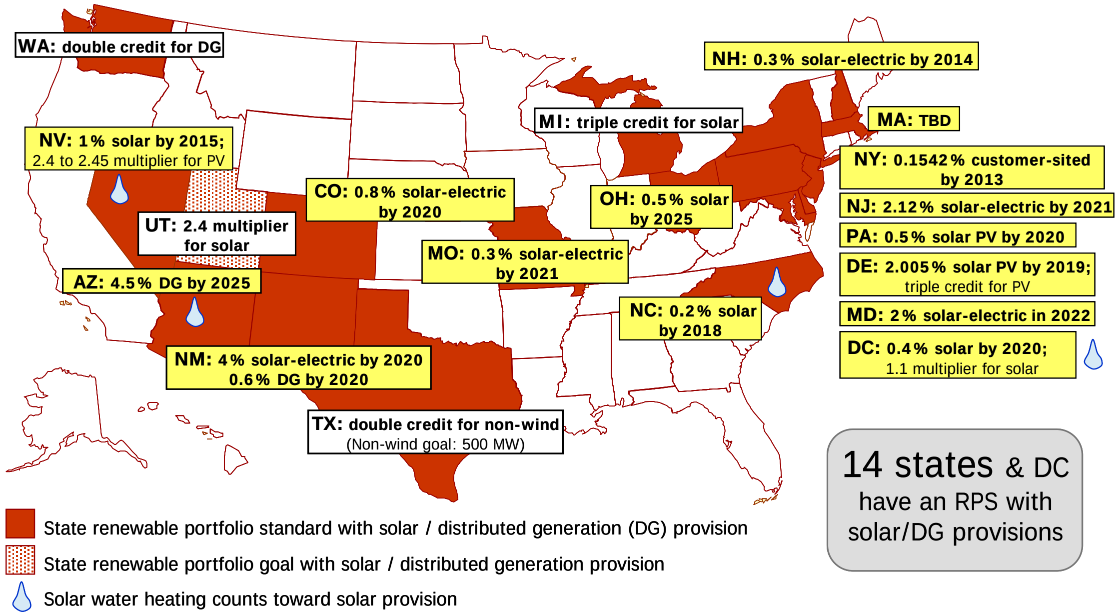
Figure 1-2. State Renewable Portfolio Standard Targets



Source: http://www.dsireusa.org. Accessed April 2009.

Some states have minimum technology requirements for certain technologies such as solar and distributed generation as shown in Figure 1-3. The percentage values in Figure 1-3 are relative to the total resources.

Figure 1-3. State Renewable Portfolio Standard Policies with Solar/Distributed Generation Provisions



Source: http://www.dsireusa.org. Accessed April 2009.

1.1.2 Renewable Energy Credit or Certificate

Many state RPS programs allow utilities to comply with the RPS requirements through tradable renewable energy credits or certificates (REC), which represent the value associated with the environmental attributes of the power generated from renewable energy resources.

Eligible renewable energy resources can earn one REC for each Megawatt hour (MWh) unit of electricity they produce. RECs can be sold and traded separately from the commodity electricity.

Utilities that do not have renewable energy resources or do not generate their own renewable-based electricity in sufficient amounts, can buy RECs from others to cover their renewable energy shortfalls. Covering these shortfalls demonstrates the utilities' compliance with their RPS obligations and to retire them through mechanisms set by the regulatory bodies.

There are a number of active REC markets in the US, with each RPS state having different eligibility requirements for RECs depending on the technology type, date of commercial operations, delivery requirements, and so on. The states and regions with mandatory RPS programs have "compliance" REC markets. Others have "voluntary" REC markets. There is currently no national REC market.

In the west, the issuance of a REC is mostly done through the Western Renewable Energy Generation Information System (WREGIS).

1.1.3 Western Renewable Energy Generation Information System

The Western Renewable Energy Generation Information System[1] (WREGIS) began operation in June 2007 as an independent renewable energy tracking system developed to track and register renewable generation by the generation resources in the Western Electricity Coordination Council (WECC) region.

WREGIS was developed through a collaborative process between the Western Governors' Association (WGA),[2] the Western Regional Air Partnership, and the California Energy Commission. WREGIS, with its administrative home at WECC, is governed by a seven-member committee, consisting of representatives from various stakeholder groups.

WREGIS is a database and an accounting software system designed to issue, register, and track RECs. WREGIS tracks the renewable generation by registered generation facilities and issues one WREGIS certificate, upon verifiable data, for each MWh of renewable energy generated by those facilities. Utilities can use WREGIS certificates to verify compliance with state RPS requirements and voluntary market programs.

Upon creation, WREGIS certificates are deposited in the private accounts of the users, similar to bank accounts, where users can transfer, retire, or export certificates to another compatible tracking system. The data on a WREGIS certificate includes MWhs produced, fuel source, facility location, and all state, provincial, and voluntary renewable energy program qualifications.

1.1.4 Colorado Renewable Portfolio Standard

In most states, the typical mechanism is for the state legislator to enact the RPS-related legislation. Bucking the trend, Colorado became the first state in the US to enact a renewable portfolio standard in November 2004 through the majority vote of the electorate in a ballot initiative.

The original Colorado RPS applied only to the investor-owned utilities (IOUs), requiring them to provide 10 percent of their energy from renewable resources. In March 2007, House Bill 1281 (HB07-1281) increased the RPS for the IOUs, and extended the RPS coverage to rural electric cooperatives (Co-ops) and municipal utilities (Munis) with more than 40,000 customers. The requirements for Co-ops and Munis are lower than those for the IOUs. Utilities can either supply the required amount of electricity from eligible renewable resources or purchase RECs from utilities that exceed the requirement to cover their target shortfalls. Summary details of Colorado's and other states' RPS programs are provided in the "Database of State Incentives for Renewables and Efficiency" (DSIRE) Web site.[3]

Table 1-1 presents the Colorado RPS targets and schedules applicable to IOUs and also to Co-ops and Munis with more than 40,000 customers. The values are the

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1 http://www.wregis.org/
2 http://www.westgov.org/
3 http://www.dsireusa.org/

percentage of renewable energy and/or recycled energy out of the total retail electricity sales supplied by each utility in Colorado.

Table 1-1. Colorado RPS Targets and Schedules

	2007	2008-2010	2011-2014	2015-2019	2020 and After
IOUs	3%	5%	10%	15%	20%
Co-ops & Munis		1%	3%	6%	10%

Source: http://www.dsireusa.org. Accessed April 2009.

As a minimum technology-type requirement, IOUs in Colorado should provide at least four percent of their RPS requirements from electricity generated by solar-electric technologies. Of this four percent, at least one-half must be generated by solar-electric systems located on-site at customers' facilities. However, there are no solar requirements for Co-ops and eligible Munis.

Colorado RPS provides a preferential treatment for eligible in-state resources. Each kilowatt hour (kWh) of electricity provided by eligible in-state renewable resources receives a 125-percent credit, i.e., it is valued at 25 percent more than out-of-state renewable energy for RPS-compliance purposes. In addition, solar electricity generated by a facility that begins operation before July 1, 2015, receives a 300-percent credit for RPS-compliance purposes. Solar electricity generated by a facility that begins operation on or after July 1, 2015, receives 100-percent credit.

A different preferential treatment is for electricity generated at a "community-based project," defined as a project not greater than 30 Megawatts (MW) in capacity that is located in Colorado and owned by individual residents of a community or by nonprofits, Co-ops, local government entities, or tribal councils, and in the service territory of electric Co-ops and eligible Munis. Such community-based projects receive 150 percent credit for RPS-compliance purposes. System owners may not take advantage of both the community-based project multiplier and the solar multiplier.

Under the current Colorado RPS, eligible renewable-energy resources include solar-electric energy, wind energy, geothermal-electric energy, biomass facilities that burn nontoxic plants, landfill gas, animal waste, hydropower, recycled energy, and fuel cells using hydrogen derived from eligible renewable resources.

1.2 Renewable Portfolio Standard Programs Across Western States

1.2.1 Comparison of Renewable Portfolio Standard Programs

All the Western states, except Idaho, Wyoming, and Utah have some kind of RPS program with mandatory targets in place. Idaho and Wyoming have no RPS regulations. The RPS in the state of Utah is not mandatory and can be viewed more as a voluntary RPS goal. Table 1-2 provides a summary overview and comparison of the RPS regulations in the Western states.

Table 1-2. Summary of Renewable Portfolio Standard Programs across Western States

State	RPS	Name (1)	Tradable RECs	Utility Type	By 2010	By 2015	By 2020	By 2025	Penalties
Arizona	Yes	RES	Yes	IOUs (2)	2.5%	5.0%	10.0%	15.0%	
California	Yes	RPS	Yes (3)	IOUs, Others (4)	20.0%		33.0%		$50/MWh (5)
Colorado	Yes	RES	Yes	IOUs	10.0%	15.0%	20.0%		
				Co-ops, Munis	1%	6%	10%		
Idaho	No								
Montana	Yes (6)	RRS	Yes	IOUs, Retail Suppliers	10%	15%			$10/MWh
Nevada	Yes	EPS	Yes	IOUs	12%	20%			
New Mexico	Yes (7)	RPS	Yes	IOUs	10%	15%	20%		
				Co-ops		5%	10%		
Oregon	Yes (8)	RPS	Yes	Large Utilities, Retailers (9)		15%	20%	25%	ACP (12)
				Small Utilities, Retailers (10)				10%	
				Smallest Utilities, Retailers (11)				5%	
Utah	Goal (13)	RPG	Yes	IOUs, Co-ops, Munis				20% (14)	
Washington	Yes	RES	Yes	Utilities (15)		3%	15%		$50/MWh
Wyoming	No								

Notes	
1	EPS = Energy Portfolio Standard, RES = Renewable Energy Standard, RPG = Renewable Portfolio Goal, RPS = Renewable Portfolio Standard, RRS = Renewable Resource Standard
2	IOUs with 50% of load in Arizona
3	If certain conditions are met, including verification of an operational WREGIS
4	Electric Service Providers, Small and Multi-Jurisdictional Utilities and Community Choice Aggregators
5	Up to $25 million per year
6	The law includes cost caps that limit the additional cost utilities must pay for renewable energy
7	Not over "reasonable cost threshold," 1% of 2006 customer costs - to grow 0.2% annually, and capped at 2%
8	Not fully required if costs exceed 4% of annual revenue requirement or if it replaces other eligible resources
9	With greater than 3% of load
10	With greater than 1.5% of load and less than 3% of load
11	With less than 1.5% of load
12	ACP (Alternative Compliance Payment) is in lieu of RPS - not strictly a penalty - value to be set
13	Meet targets to the extent that it is "cost-effective" to do so, with no interim targets until 2025
14	Utilities with greater than 25,000 customers
15	Of adjusted retail sales: excluding sales from nuclear, DSM, and carbon sequestered fossil based resources

Source: http://www.dsireusa.org. Tabulation by R. W. Beck.

1.2.2 Renewable Portfolio Standard Restrictions

Examination of programs in the Western states indicates that there are a few restrictions embedded within state RPS programs or other laws that make in-state resources preferable to importing Colorado resources. Arizona, for instance, requires that eligible resources must be deliverable to the state. Nevada provides preferential credit of 245 percent to Nevada customer maintained photovoltaic solar energy. As shown in Table 1-3, Montana's RPS rules have a number of provisions that are meant to promote in-state rural renewable development. Colorado's own preferential treatment of in-state renewable resources is the most emphatic within WECC. Table 1-3 also lists the states that specified minimum technology requirements, mostly favoring solar-based resources by assigning more than a 100 percent RECs to such resources, but the regulations do not appear to restrict the preferential treatment of such resources to in-state resources.

Table 1-3. Renewable Portfolio Standard Technology and In-State Resource Preferences

Technology and Other Requirements	
Arizona	20% of RPS from Distributed Renewable by 2010, 30% by 2012 and after
Colorado	4% of RPS from Solar (50% of which Customer Site)
Nevada	5% of RPS must be Solar, Contribution from eligible Energy Efficiency towards RPS capped at 25% of RPS PV credited at 240% Energy Efficiency savings credited at 105%, Energy Efficiency savings at peak periods, credited at 105%
New Mexico	By 2020, 20% of RPS from Solar, 20% of RPS from Wind By 2020, 10% of RPS from Geothermal and Biomass, 3% of RPS from Distributed Renewable Diversification targets are exempted if they impact reliability or if the generation cost increased by more than 2%
Oregon	By 2025 at least 8% of retail load from small-scale projects with a capacity of 20 MW or less
Utah	Unbundled RECs can only meet 20% of a large utility's and 50% of a large consumer-owned utility's obligation. Solar credited at 240%
Preferences for In-State Resources	
Arizona	Energy produced by eligible renewable-energy systems must be deliverable to the state. Extra credit multipliers may be earned for early installation of certain technologies, in-state solar installation, and in-state manufactured content. The multipliers are additive, but cannot exceed 2.0. Utility investing in or providing incentives for solar electric manufacturing plant to locate in state can acquire RECs equal to the capacity of the panels produced multiplied by 2,190 hours. These RECs cannot account for more than 20% of the annual requirement.
Colorado	In-State Generation credited at 125% Community Based Projects <= 30 MW credited at 150% Solar prior to 2015 credited at 300%
Montana	Provisions for community renewable energy projects (CREP) (under 25 MW) with local controlling interest. For compliance year 2011 to 2014, public utilities must purchase both the RECs and the electricity from CREPs totaling at least 50 MW in nameplate capacity. For compliance year 2015 and after, public utilities must purchase both the RECs and the electricity from CREPs totaling at least 75 MW in nameplate capacity. In addition, public utilities must enter into contracts that include a preference for Montana workers.
Nevada	PV maintained by customers credited at 245%

Source: http://www.dsireusa.org. Accessed April 2009. Tabulation by R. W. Beck.

2.1 Overview of Colorado's Electricity Market

2.1.1 Regional Structure

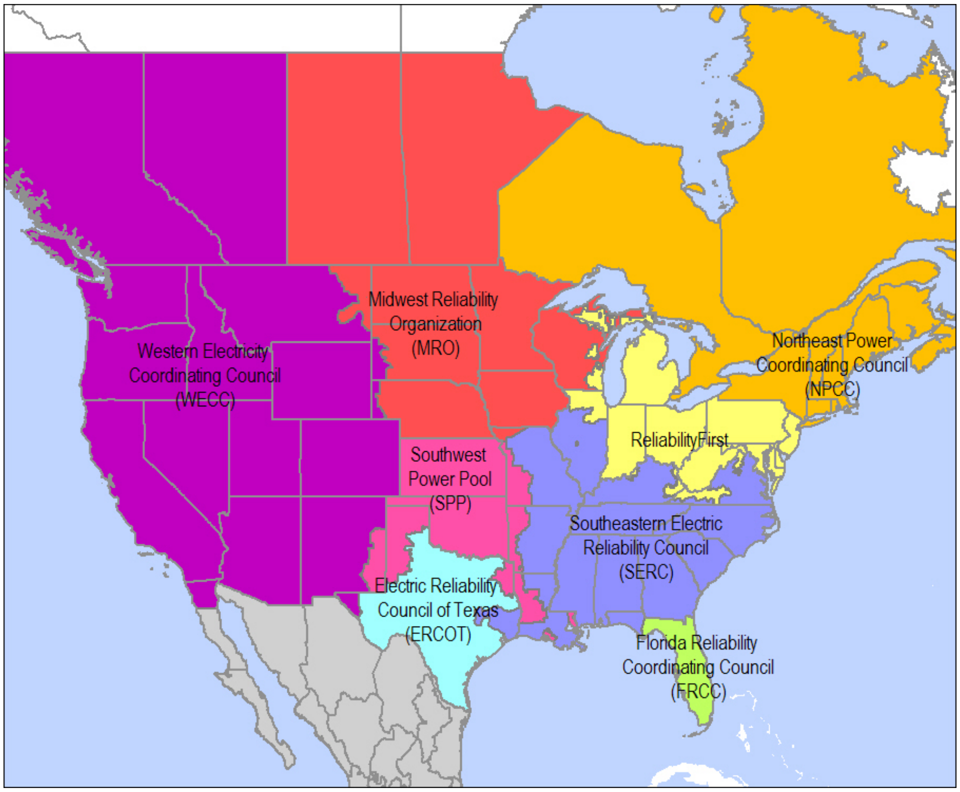
Colorado's electricity market is in the footprint of the WECC, one of the eight electric reliability councils of the North American Electric Reliability Corporation (NERC).

NERC's mission is to ensure the reliability of the bulk power system in North America. To achieve that, NERC develops and enforces reliability standards; assesses reliability annually via 10-year and seasonal forecasts; monitors the bulk power system; evaluates users, owners, and operators for preparedness; and educates, trains, and certifies industry personnel. NERC is a self-regulatory organization, subject to oversight by the United States Federal Energy Regulatory Commission ("FERC" or "the Commission") and governmental authorities in Canada. NERC was certified as the Electric Reliability Organization (ERO) by FERC on July 20, 2006.

The reliability regions covered under NERC consist of four separate interconnections: WECC, Electric Reliability Council of Texas, Eastern Interconnection, and the Quebec interconnection. The four interconnections have no Alternative Current (AC) connections, and therefore, their operations are non-synchronous, which means that operations in one interconnection does not impact operations in others, and that current frequency is maintained separately in each interconnection. However, the interconnections have Direct Current (DC) connections, where disturbances in one interconnection would not impact operations in other interconnections, since flows over DC ties are controllable.

As shown in Figure 2-1, there are a total of eight NERC reliability councils overseen by NERC.

Figure 2-1. NERC Reliability Regions

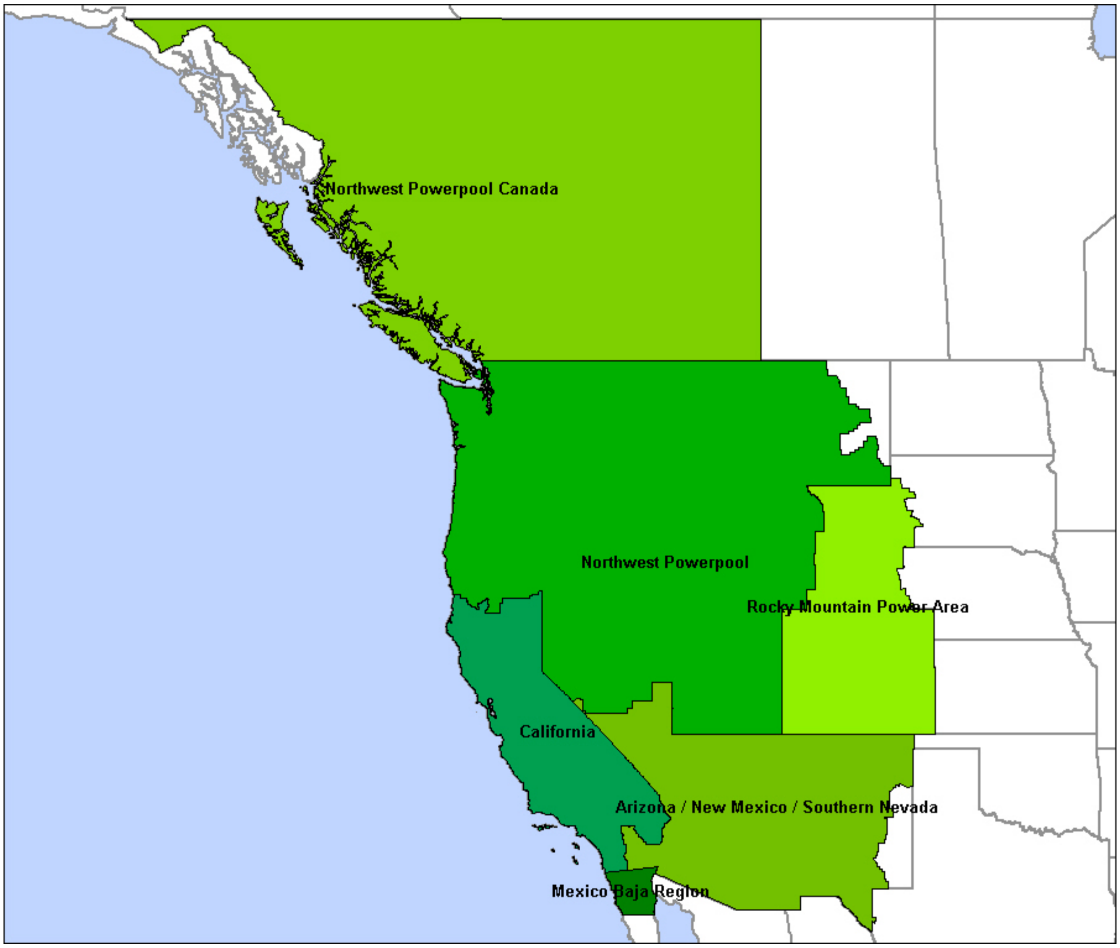


2.1.2 Western Electricity Coordinating Council Sub-regions

WECC is one of the eight electric reliability councils within NERC and the only council in the Western Interconnection. It covers 14 western states and parts of Canada and Mexico. WECC was formed in April 2002 from the merger of the Western Systems Coordinating Council, Western Regional Transmission Association, and Southwest Regional Transmission Association. As shown in Figure 2-2, WECC is divided into a number of sub-regions:

- California/Mexico Baja Region.
- Arizona/New Mexico/Southern Nevada.
- Northwest Power Area – USA.
- Northwest Power Area – Canada.
- Rocky Mountain Power Area (RMPA).

Figure 2-2. Western Electricity Coordinating Council Regions



2.1.3 Western Electricity Coordinating Council Market Structure

The reporting areas under WECC have diverse market structures, each with its own individual generation supply and load features. The utility structures in each sub-region encompass a mix of IOUs, Munis, municipal joint action agencies, rural electric associations (REAs) or Co-ops, generation and transmission associations, and two federal power marketing administrations. All of the markets in the WECC region, except the California/Mexico Baja Region, are bilateral in nature and without a structured wholesale market. In the non-California/Mexico Baja Region markets, almost all transactions are through bilateral contracts, with most of the larger public utilities retaining their traditional vertically integrated structure.

In contrast to other WECC markets, the California/Mexico Baja Region market, except for some areas covered by municipal and public power entities, is a competitive wholesale market run by the California Independent System Operator (CAISO). The

CAISO launched a nodal market, a locational marginal price-based market, referred to as the Market Redesign and Technology Upgrade on April 1, 2009.[4]

2.1.4 Rocky Mountain and Colorado Market

The RMPA is a sub-region of the WECC. It covers all of the state of Colorado, parts of central and all of eastern Wyoming, and portions of western Nebraska and South Dakota.

RMPA consists of a mix of IOUs, Munis, REAs, generation and transmission associations, and federally owned Western Area Power Association (WAPA). The RMPA market is based purely on bilateral transactions, with local regulated utilities being responsible for balancing the hourly markets. RMPA markets do not belong to a Regional Transmission Organization (RTO) and do not operate a separate Independent System Operator (ISO) type competitive market. Wholesale customers obtain transmission service through agreements executed pursuant to individual utility Open Access Transmission Tariffs (OATT) filed with the FERC.

RMPA currently does not have a process for assessing resource adequacy on a region-wide basis. However, individual entities address resource adequacy requirements as part of their integrated resource planning needs.

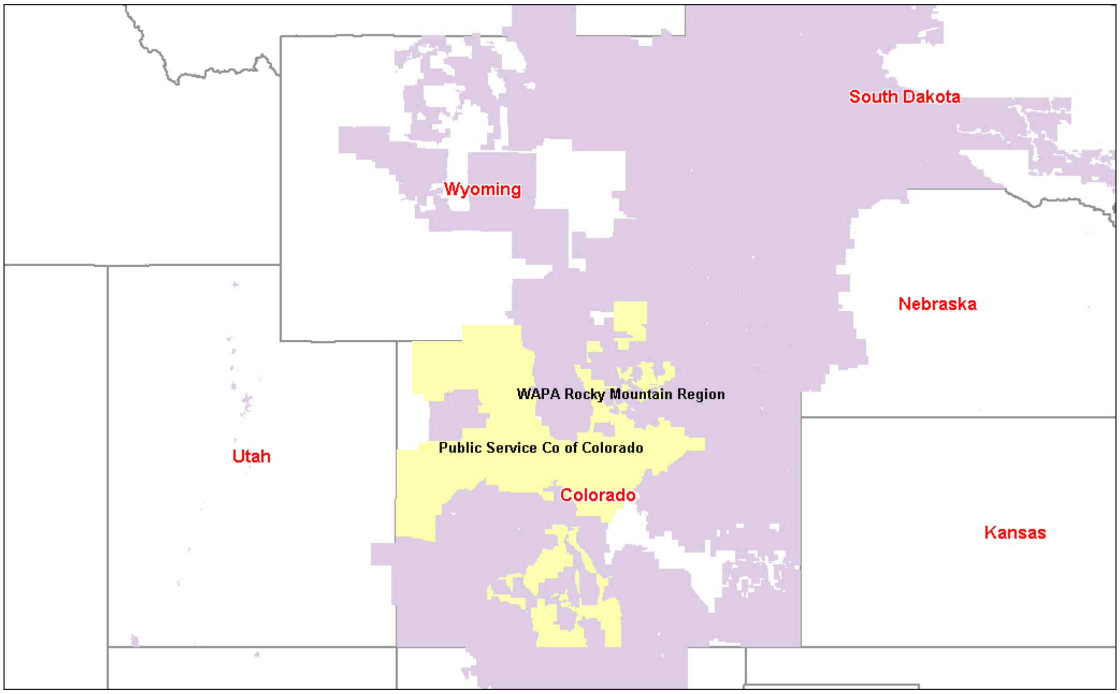
As displayed in Figure 2-3, the balancing authorities, i.e., control areas, in the RMPA include the Public Service Company of Colorado (PSCo) and WAPA. Having multiple control areas in a region may contribute to less efficient allocation of region-wide energy, capacity, and operating reserve resources.

There are no centralized exchange markets specific to the region, and there are no electricity trading hubs within RMPA, which contributes to a lack of transparency of the wholesale market operations and wholesale prices. The nearest trading hub is the Four Corners hub near the geographic meeting point of the states of Colorado, New Mexico, Arizona, and Utah, where physical and financial electricity products are traded through brokers.

Bilateral transactions are negotiated directly between suppliers and load serving entities, and are scheduled through individual transmission owners. As a result, prices and terms are generally tailored for each transaction and are less transparent compared to the more organized ISO-type markets.

[4] http://www.caiso.com/2383/23837b9467860.pdf

Figure 2-3. Control Areas in the Rocky Mountain Power Area



By some accounts, non-transparency of prices, lack of available system and network information, and disjointed operation of the sub-regional power systems may result in less efficient generation dispatch and utilization of the transmission system. For instance, to mitigate for potential system deficiencies, exacerbated by lack of shared information, transmission owners hold part of their transmission capacity as unused "reserves" to ensure reliable system operation, resulting in potentially limiting transmission access to some merchant generation and other transmission customers including wholesale buyers, and thus negatively impacting market competition and efficient allocation of resources.

There has been some discussion and attempts to establish an RTO or ISO-type market and/or a centralized transmission operator. However, these efforts have not been successful, mostly due to the peculiar structure of the RMPA markets with their mix of IOUs, Co-ops, Munis, and federally owned power marketing administrations operating under various jurisdictions.

A non-profit membership entity called Desert Start, or DSTAR, was started in 1997, which was then transformed into WestConnect in 2001, with the objective of improving the transmission planning process in the RMPA and the Arizona/New Mexico/Southern Nevada regions. However, WestConnect appears to be more of a coordinated and collaborative planning entity, rather than an RTO- or ISO- type entity, or the pre-ISO power pools in the former regulated markets, where savings from pooling resources among voluntary participants were split among the participants under the so-called "split-the-savings" principle.

2.1.5 Rocky Mountain Power Area Peak Demand and Energy

The RMPA annual peak demand occurs in either the summer or winter season due to variations in the weather. According to NERC's "2008 Long-Term Reliability Assessment,"[5] for the period from 2008 through 2017, summer total internal demands and annual energy requirements were projected to grow at annual compound rates of 2.35 and 2.24 percent, respectively. The shortfall in 2017 between the "Planned" reserve resources (15,418 MW), including 398 MW of interruptible load, and the total internal demand plus target margin (16,880 MW) is expected to be -1,462 MW. The annual energy use for the nine-year period from 2008 through 2017 is forecast to increase by 2.2 percent, compared to the historic annual energy use increase of 3.0 percent from 1997 through 2007. The target reserve margin from RMPA is 11.8 percent for the summer and 13.4 percent for the winter.

According to NERC's "2008 Summer Reliability Assessment,"[6] the 2008 summer peak demand forecast of 12,285 MW is 3.0 percent greater than 2007's actual peak demand of 11,931 MW and is 6.4 percent greater than 2007's forecast peak demand of 11,547 MW. The 2007 summer peak demand was higher than expected due to warmer temperatures. The forecast peak demand includes 242 MW of interruptible demand and load management capability. The projected capacity margin for the peak month (July) is 12.5 percent, which equates to a 14.2-percent reserve margin.

According to NERC's "2008/2009 Winter Reliability Assessment,"[7] the 2008/2009 winter peak demand of 10,529 MW was projected to occur in December and to be 5.1 percent greater than the previous winter's actual peak demand of 10,014 MW, which occurred in January. The 2008/2009 winter peak forecast is 7.4 percent greater than the last winter's projected forecast peak demand of 9,807 MW, which was projected to occur in December 2007. The expected load growth for the 2008/2009 winter season is attributed to continued residential, commercial, and industrial growth. The 2007/2008 winter season's peak demand was 2.1 percent higher than what was forecast (9,807 MW). The forecast peak demand includes 131 MW of interruptible demand and load management capability. The projected capacity margin for the peak month is 23.0 percent, which is equivalent to a reserve margin of 29.9 percent.

The current economic downturn should put a damper on the regional load growth and there is an expectation that the electricity load growth trends of the past will not be sustainable in the near future.

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[5] NERC, "2008 Long-Term Reliability Assessment," October 2008.

[6] NERC, "2008 Summer Reliability Assessment," May 2008.

[7] NERC, "2008/2009 Winter Reliability Assessment," November 2008.

2.1.6 Capacity and Generation Mix

The dominant generation resources in RMPA and Colorado are coal-fired and gas-fired plants. The region is resource rich in coal and gas. Rocky Mountain and Colorado utilities have historically relied on low-cost coal resources, which are readily available in the Rocky Mountain region. Power plants sometimes are located near a coal mine, which helps to reduce costs, since transportation is a large part of the cost of delivering coal to electric generating plants. Coal is often procured through long-term contracts. However, the Rocky Mountain area has been experiencing rapid growth in natural gas production. Gas-fired plants are most often operated in a peaking mode, and as a result, the marginal fuel type is natural gas.

Figures 2-4 and 2-5 show the capacity and generation mix by fuel types in the Rocky Mountain region. Figures 2-6 and 2-7 show the capacity and generation mix by fuel type in Colorado. As shown in the figures, coal is the overall dominant capacity resource, in terms of MWs, in the Rocky Mountain region, but has fallen behind gas in Colorado. However, in terms of gigawatt hours of generation, coal-based electricity is dominant both in the Rocky Mountain region and also in Colorado. The implication is that even if gas-based capacity is greater than the coal-based capacity in Colorado, the coal-fired plants run longer and/or at higher utilization during the year compared to the gas-based capacity, or in other words, the coal-fired plants on the average have a higher capacity factor than the gas-fired plants.

Figure 2-4. Rocky Mountain Power Area Operating Capacity Mix (MW) by Fuel Type in 2007

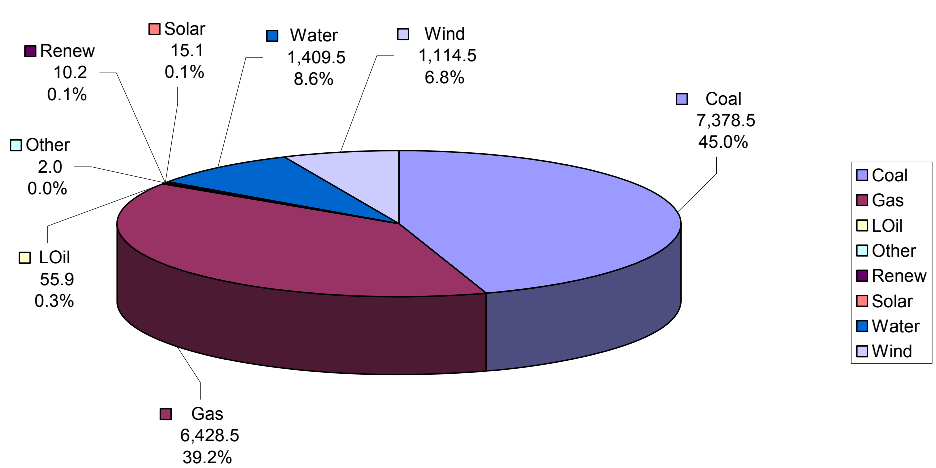


Figure 2-5. Rocky Mountain Power Area Generation Mix (gigawatt hour) by Fuel Type in 2007

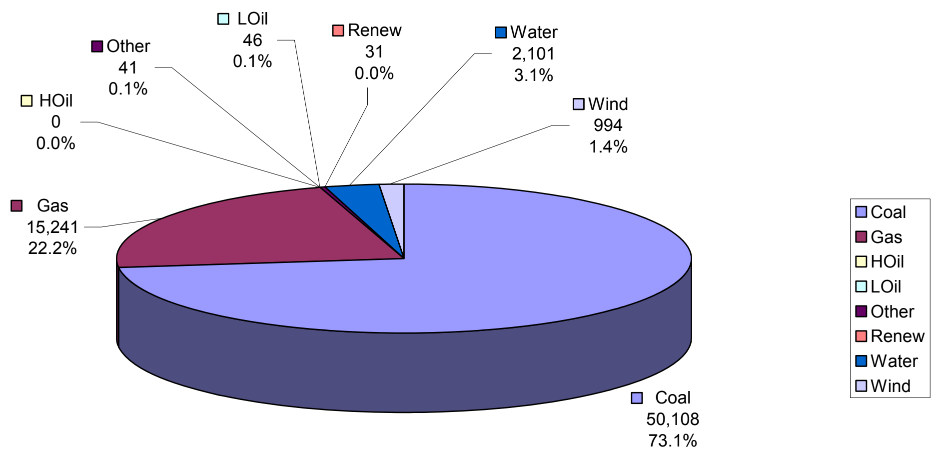


Figure 2-6. Colorado Operating Capacity Mix (MW) by Fuel Type in 2007

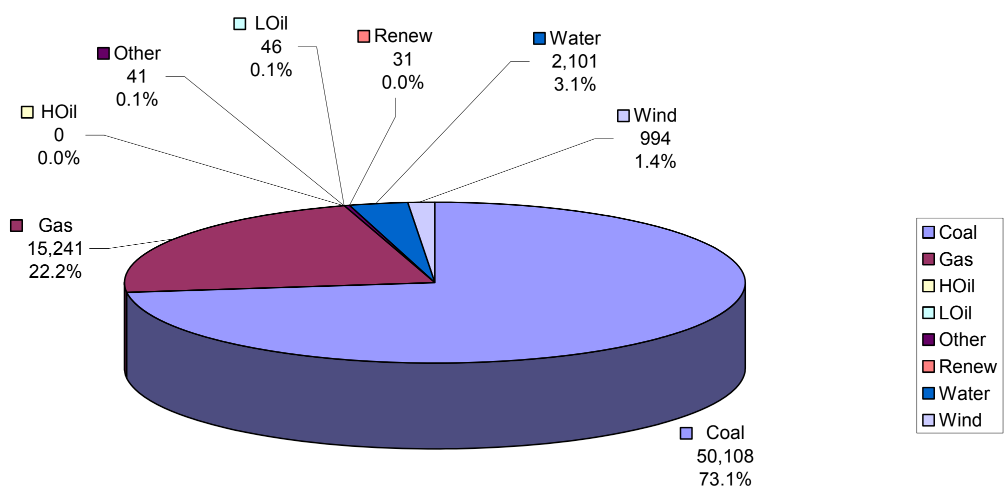
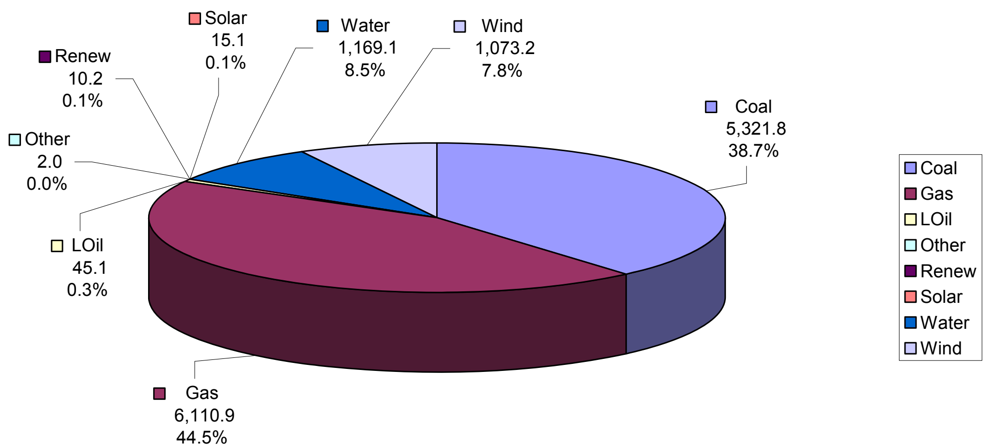


Figure 2-7. Colorado Generation Mix (gigawatt hour) by Fuel Type in 2007



2.1.7 Generation Vintage in the Rocky Mountain Area

Figures 2-8 and 2-9 depict the vintage of generation in the Rocky Mountain region by their fuel type and prime mover type. The older plants are mostly either hydroelectric power plants or coal-burning or gas-fired steam plants. Hydroelectric power plants usually have a long service life. Many of the older coal-fired and gas-fired steam plants have been operating for more than 40 years. Typically the most polluting, or greenhouse gas emitting, are the coal-fired steam plants and the least efficient plants are the oil and gas-fired steam plants.

In the near future, these older plants will be candidates for retirement based on their vintage alone, and their replacements, in all likelihood, would either be super clean or "green" fossil fuel-based or renewable resource-based power plants in the region.

Figure 2-8. Generation Vintage in Rocky Mountain Power Area by Fuel Type

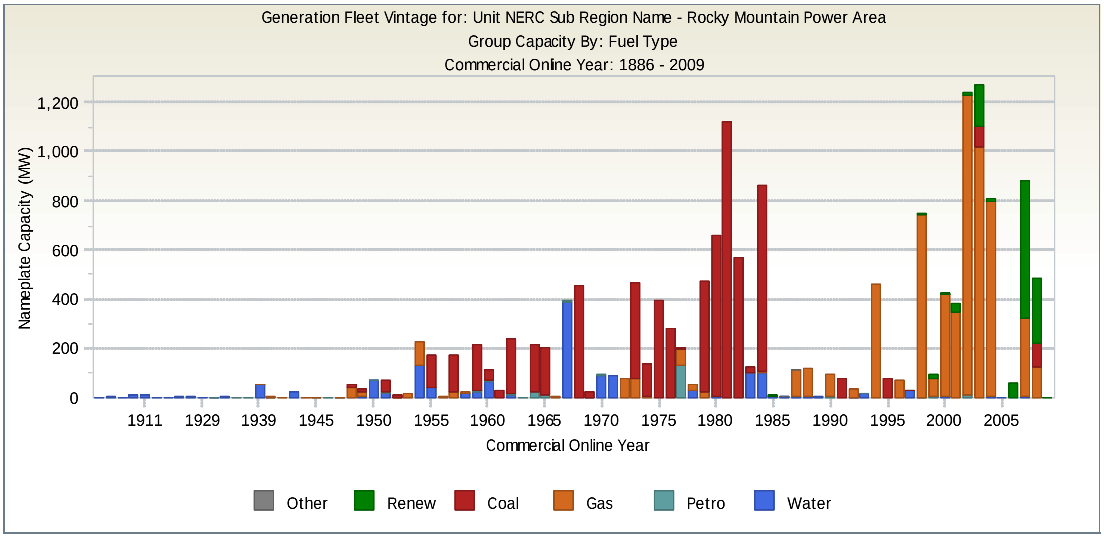
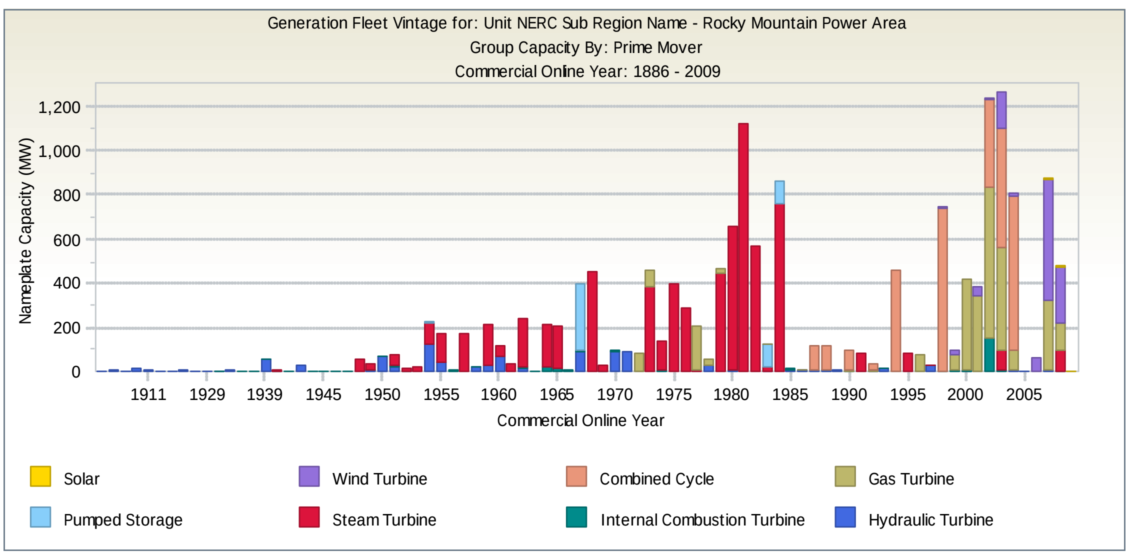


Figure 2-9. Generation Vintage in Rocky Mountain Power Area by Prime Mover



2.1.8 Rocky Mountain and Colorado Load and Supply

Figures 2-10 to 2-15 illustrate the relative annual load and capacity supply in Colorado and the Rocky Mountain region. The underlying data include the existing power plants and future power plants that have been announced and are at various stages of development. The figures do not include any unannounced future plants that will be needed to meet an acceptable level of installed reserve margin and hence an acceptable level of resource adequacy in the region.

Capacity supplies in these figures are identified by their status, i.e., existing or at different stages of development, or by their fuel or mover type. The charts may not include all the proposed plants at their various stages of consideration, particularly the renewable energy resources with short lead-times, due to difficulty in confirming the genuineness of the announcements, or the time it takes to update and adjust the underlying database with information in a rapidly changing environment. The charts also include a proposed future nuclear power plant with a commercial operating year of 2018, resulting in a spike in reserve margin in that year. However, whether the announced plant will become a reality on the ground on such a short time horizon needs to be seen. Furthermore, the load growth projections shown may be an overestimation, since the current economic downturn is expected to dampen the load growth.

Nevertheless, the displayed charts emphatically show that in the very near future, without any additional new capacity coming online, the installed reserve margin will drop below the industry-norm target of 15 percent. The interesting question to contemplate is, what type of power plants will be built to maintain an acceptable level of reserve margin?

Figure 2-10. Supply and Demand Report by Plant Status - Colorado

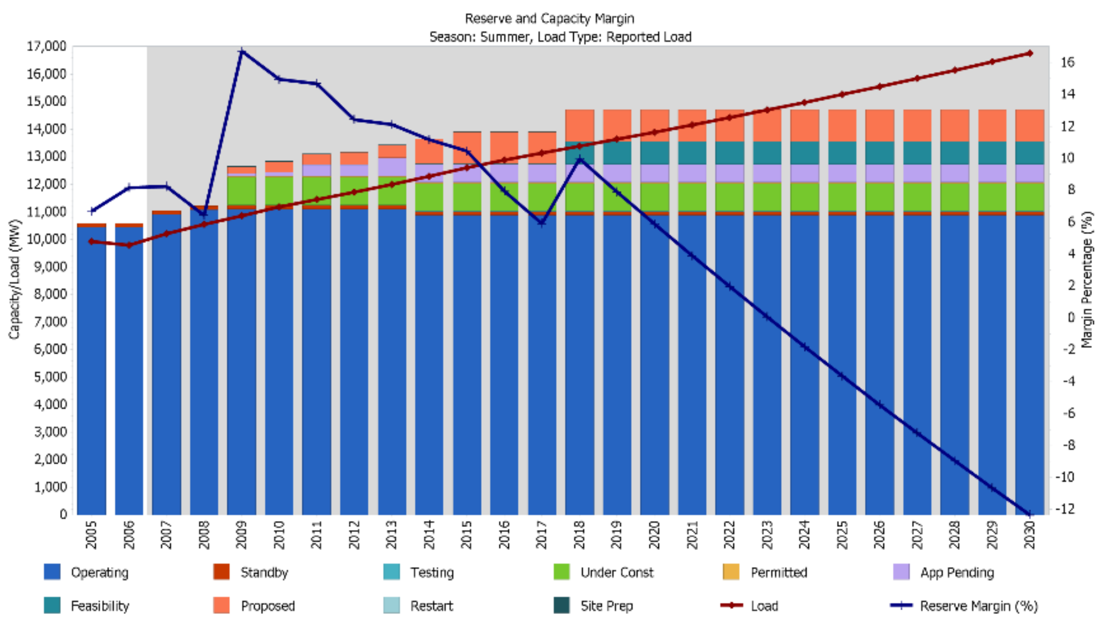


Figure 2-11. Supply and Demand Report by Fuel Type - Colorado

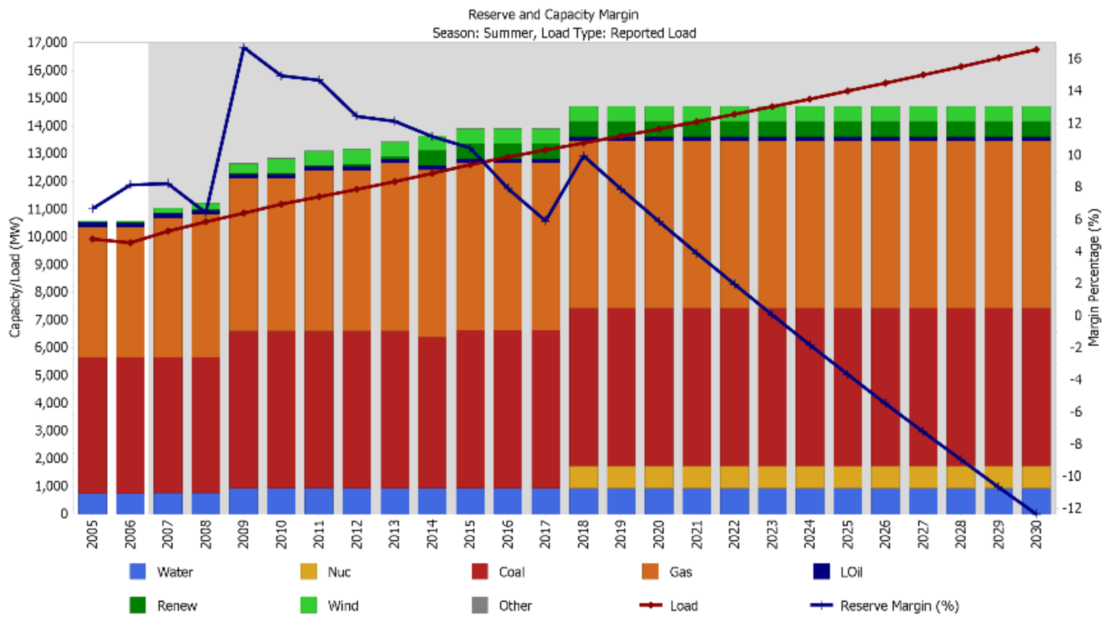


Figure 2-12. Supply and Demand Report by Prime Mover Type - Colorado

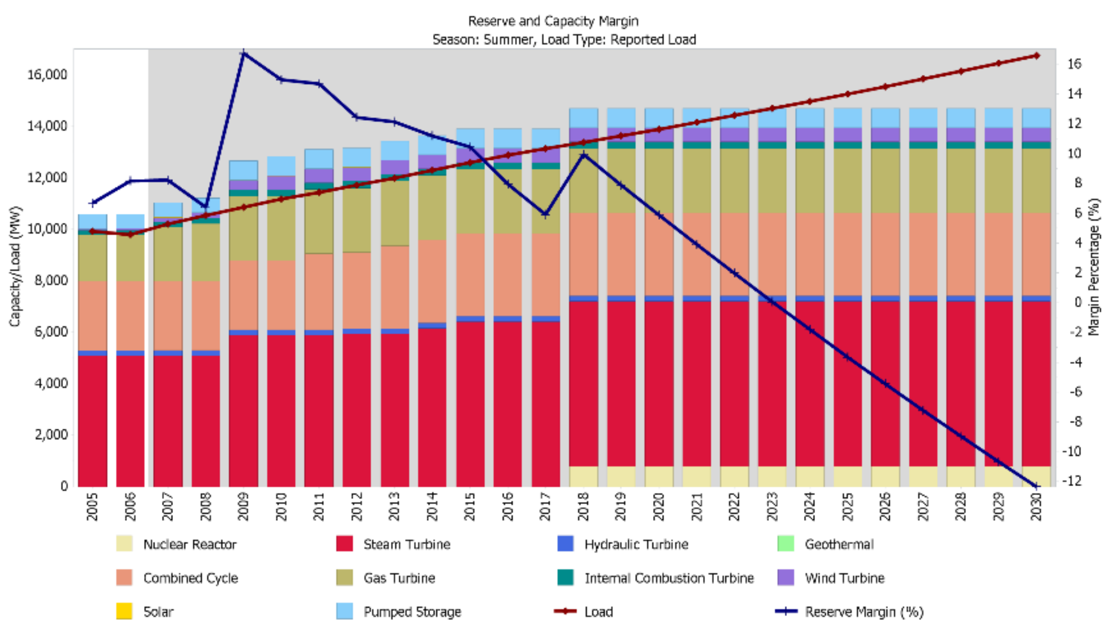


Figure 2-13. Supply and Demand Report by Plant Status – Rocky Mountain Power Area

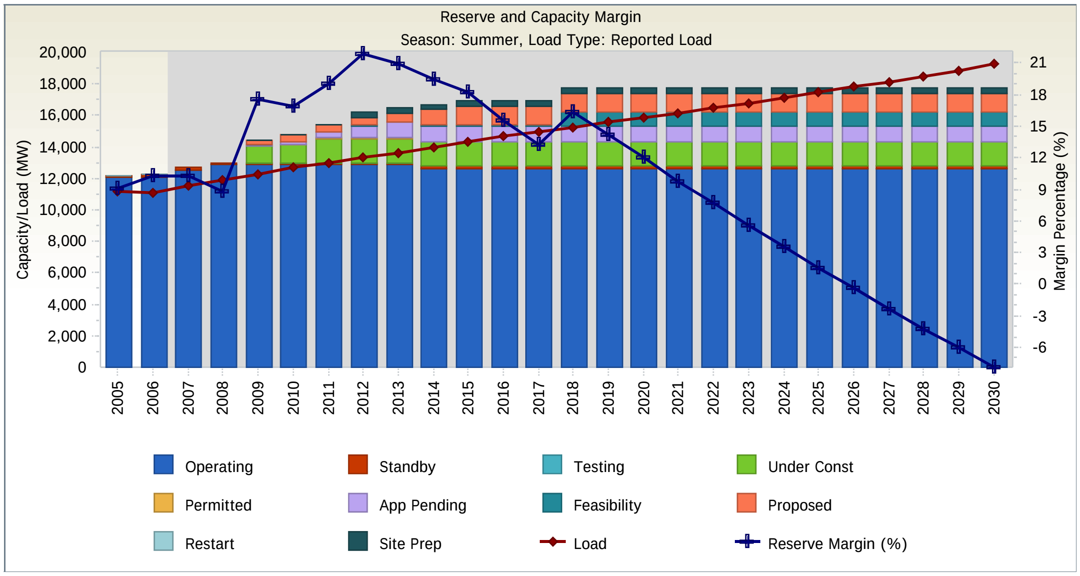


Figure 2-14. Supply and Demand Report by Fuel Type – Rocky Mountain Power Area

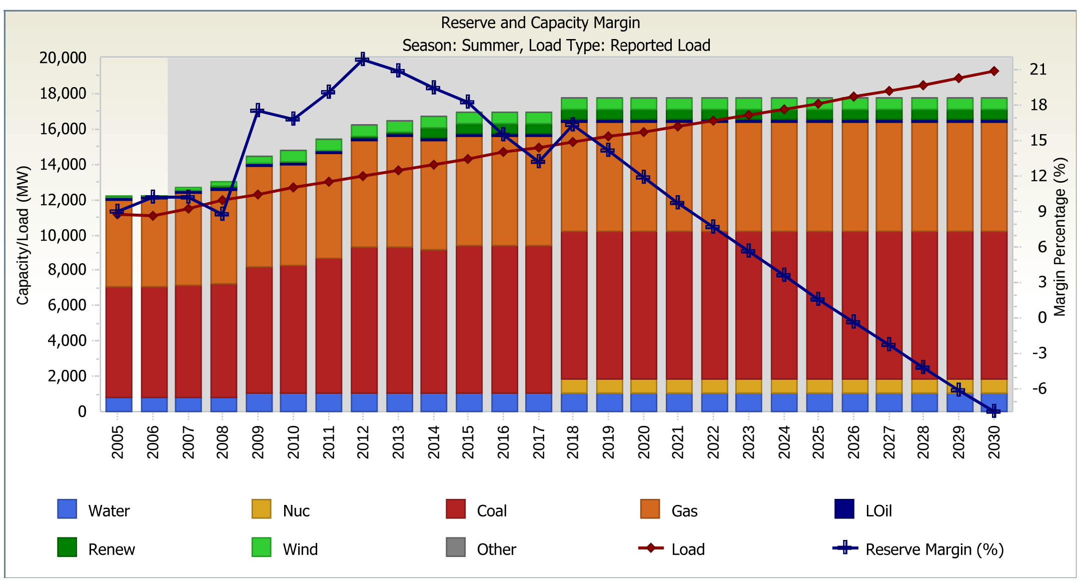
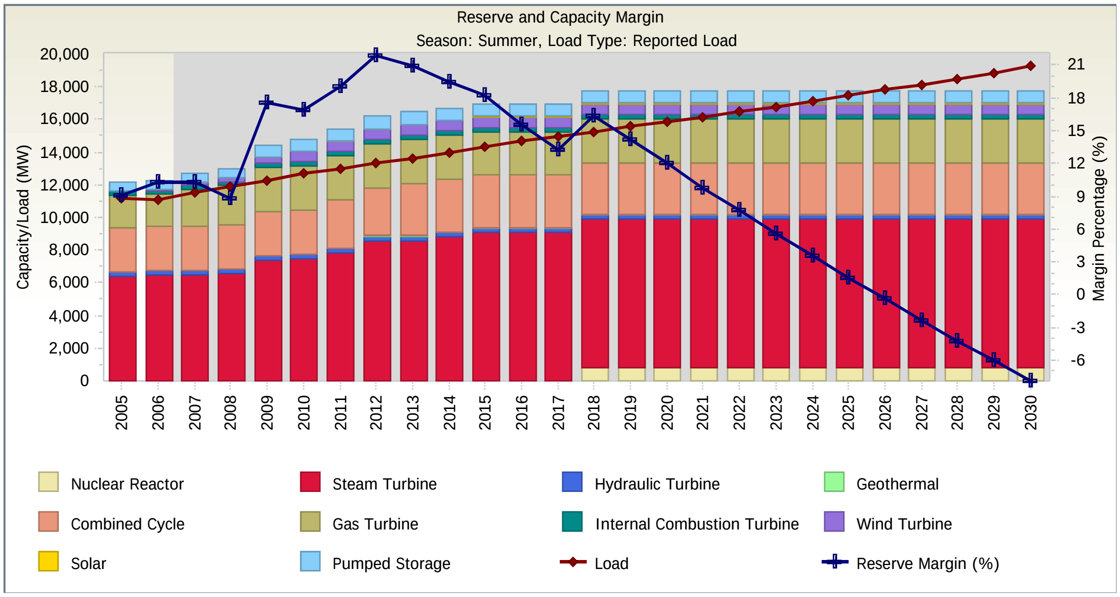


Figure 2-15. Supply and Demand Report by Prime Mover Type
Rocky Mountain Power Area



2.1.9 Generation Merit Order Cost Curves

Figures 2-16 and 2-17 display the generation merit order cost curves in RMPA. The merit order curves are constructed by stacking up the generation supply from the least expensive to most expensive units in terms of their variable cost (Dollar/Megawatt hour) of operation. A merit order cost curve shows the marginal variable cost of electricity production at any level cumulative capacity needed to meet the load. The charts identify the categories of different fuel types on the cost curves.

Figure 2-16 assumes no carbon costs, i.e., no carbon dioxide emission allowance costs. Figure 2-17 assumes a hypothetical carbon cost or carbon dioxide emission allowance cost of $20/ton to represent a future time when and if either a carbon tax or carbon cap and trade regime takes effect. Figures 2-18 and 2-19 are similar to Figures 2-16 and 2-17, except that the capacities on the merit order curves are identified by the plant's primary mover instead of by fuel type. On all the merit order cost curves, the vertical lines identify the average load and high and low loads during the year in the region. Any capacity below the minimum load would be expected to be dispatched in every hour of the year, if available, since they are the least expensive to operate. Any capacity above the maximum load will probably not be dispatched at all, except when there are forced or scheduled outages of other generation units in the system, necessitating utilization of these more expensive generation units.

What these figures show is that additional carbon-related costs will result in changing the relative costs of generation types and their relative place on the merit order curve, which will directly impact how much they get dispatched, and therefore, their capacity factor and relative economics. These charts assume that carbon costs for each type of generation unit will be reflected in the dispatch price of the units as an emission's cost "adder" to the units' variable costs. In other words, any carbon costs will be passed to the electricity customers. The more carbon a plant produces, the higher its variable costs and its relative movement to the right on the merit order curve will be, and the fewer hours it would run, assuming unit dispatch were based on relative variable generation costs. As can be observed in the charts, not only does the merit order curve move up vertically (due to an increase in variable generation costs), the placement of different fuel and prime mover types change on the merit order curve. For instance, a previously low cost coal-fired unit would move to the right on the curve, and get replaced by a less expensive (and less carbon generating) gas-fired unit.

The introduction of a carbon regime would only have a positive impact on the renewable energy resources. Since these resources have practically zero variable costs (they burn no fuel), they are expected to be dispatched whenever their primary energy source, i.e., the wind or the sun, are available. Even a renewable resource-based generation plant with high capital costs, to the extent that it has a contract to sell power, could produce energy whenever it can. The main impact of a carbon regime would be an increase in power prices, which in a deregulated competitive market would translate to higher revenues for the renewable energy resources.

Another important impact of a carbon regime would be a potentially drastic change in the mix of future generation that will be built to keep up with the load growth; and with coal-fired generation becoming costlier, the expectation is a potentially higher emphasis on the development of renewable energy resources due to their expected comparative economic advantage.

Figure 2-16. Rocky Mountain Power Authority Cost Curve by Fuel Type
(No Carbon Costs)

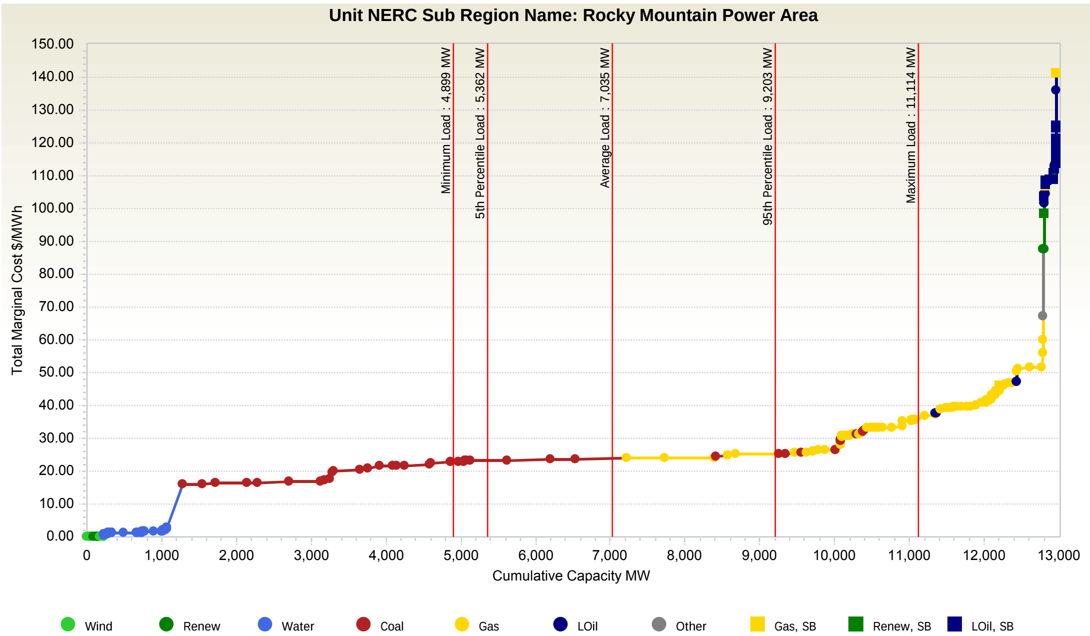


Figure 2-17. Rocky Mountain Power Authority Cost Curve by Fuel Type
($20/Ton Carbon Costs)

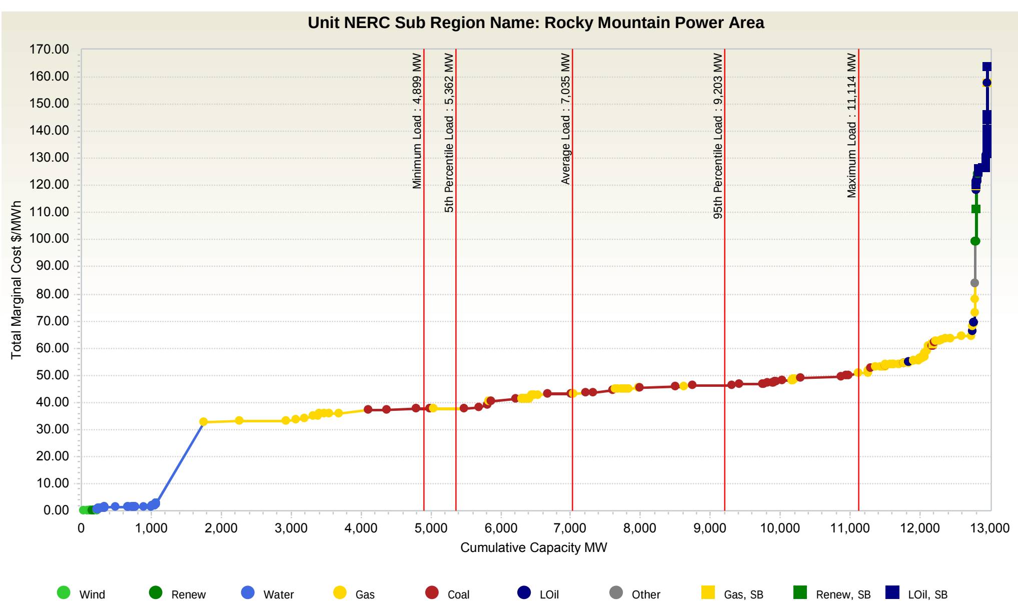


Figure 2-18. Rocky Mountain Power Area Cost Curve by Mover Type
(No Carbon Costs)

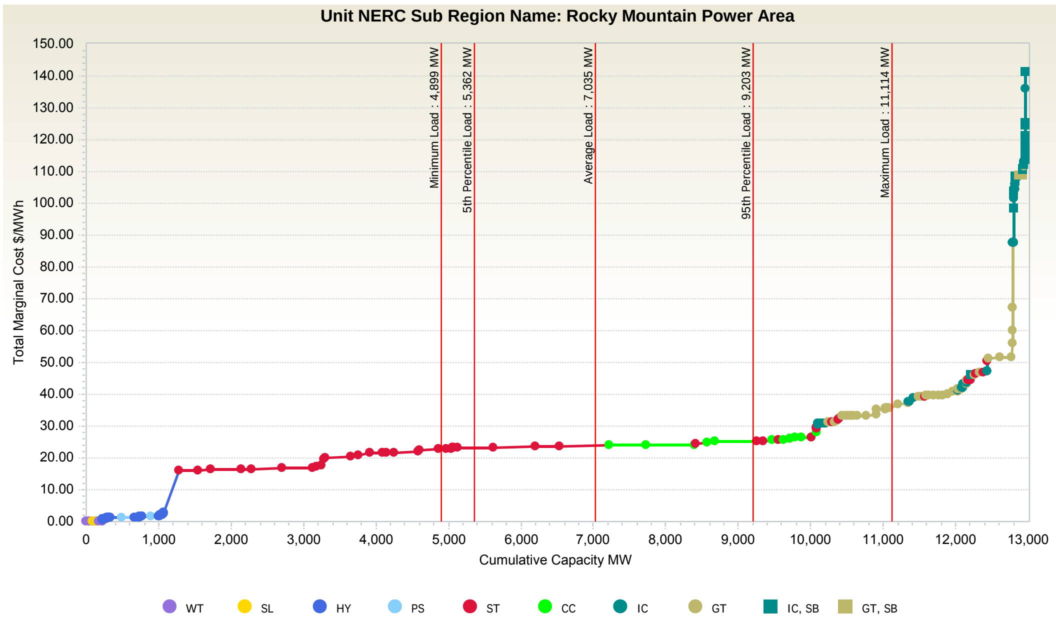
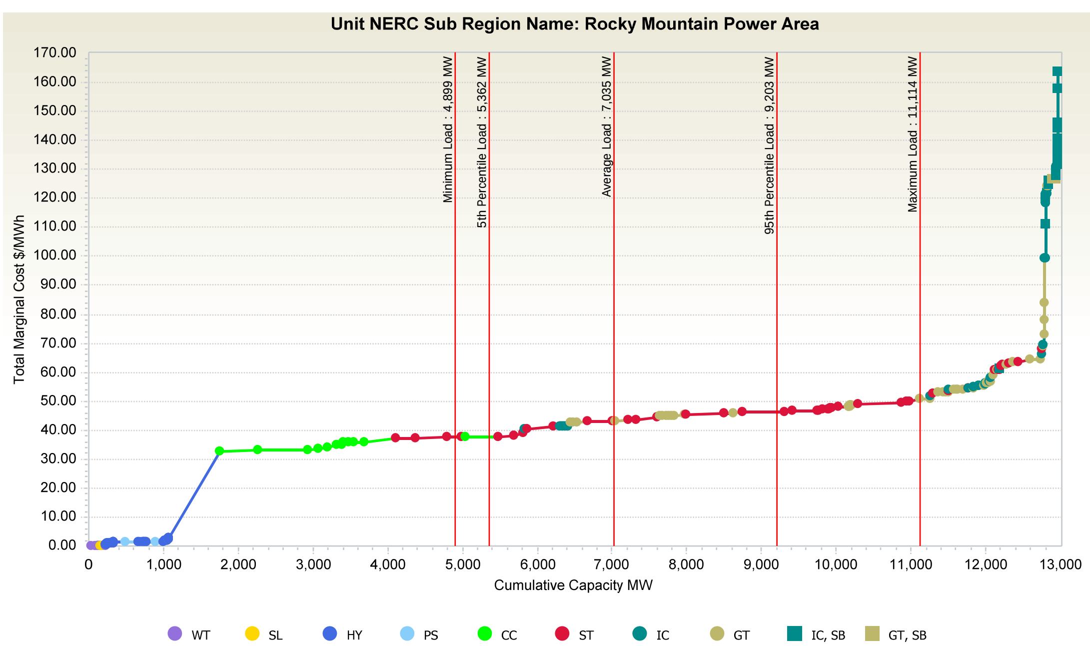


Figure 2-19. Rocky Mountain Power Area Cost Curve by Mover Type
($20/ton Carbon Costs)



2.1.10 Historical Electricity and Gas Prices in the Region

Figure 2-20 shows the historical electricity price in the Four Corners electricity hub, the nearest trading electricity hub to Colorado, and the Colorado Interstate Gas Company's mainline gas hub. Figure 2-21 depicts the historical on-peak and off-peak electricity prices in Four Corners and the gas price for comparison.

These charts illustrate that there is some correlation between historical power and gas prices, particularly the on-peak prices. It should be noted that even the Four Corners hub is not a reliable proxy for the power prices in Colorado. This is because the transmission capacity from Four Corners due west is highly utilized by the coal-fired electricity generation at that location, and the trading at Four Corners is not as voluminous as trading in other WECC trading hubs such as Palo Verde, Malin, SP15, NP15, COB, and Mid-C. Some of the spikes in power prices in the Four Corners area could be due to local events in the that area or in regions further west, because of actual or expected shortages in generation supply or transmission capacity in another location.

Nevertheless, the charts illustrate that gas price volatility in the region does translate to the wholesale market power price volatility, particularly during on-peak times. One benefit of renewable resources is their disassociation with prime energy source price levels and their volatility.

Figure 2-20. Historical Four Corners Power vs. Colorado Interstate Gas Company's Mainline Gas Prices

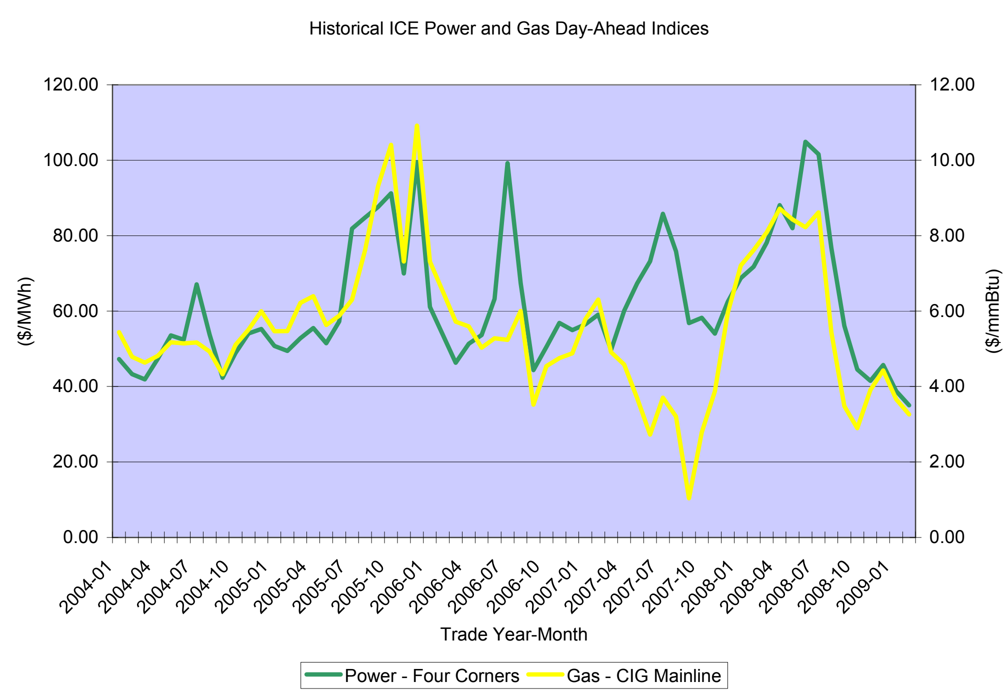
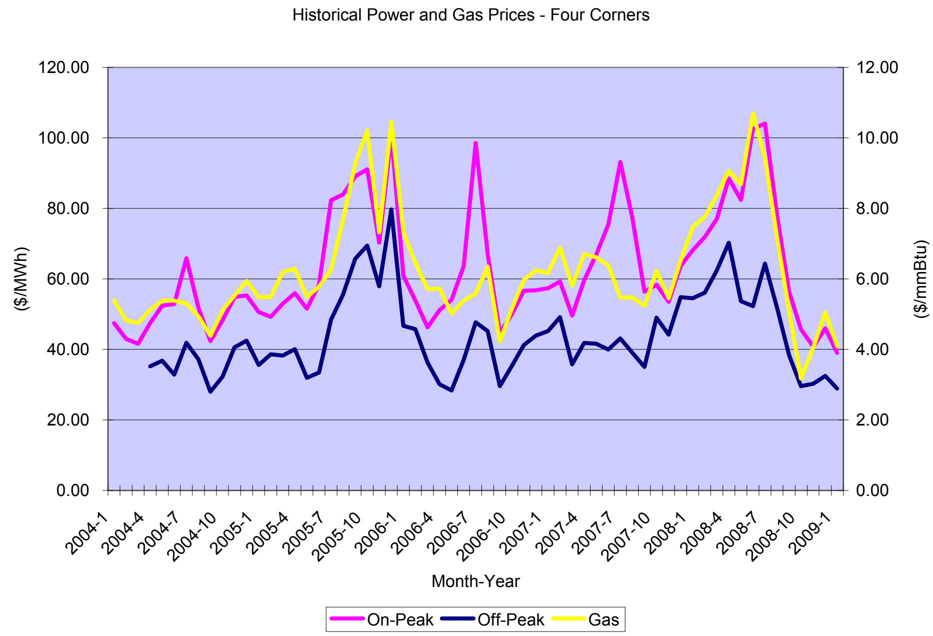


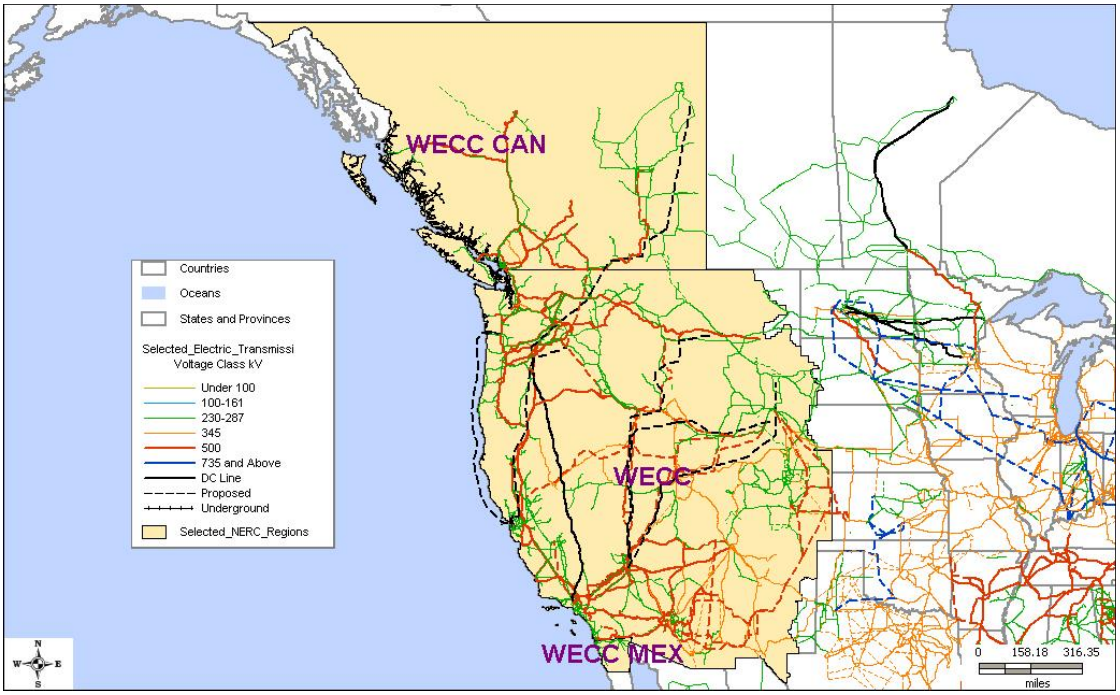
Figure 2-21. Historical Four Corners' Power On-Peak and Off-Peak vs. Colorado Interstate Gas Company's Mainline Gas Prices



2.2 Western Electricity Coordinating Council and Colorado Transmission

The western US interconnection facilitates the mostly summer peak time north to south power transfer from the northwest to California. Figure 2-22 provides an overview of the transmission grid in the WECC.

Figure 2-22. WECC Transmission Grid

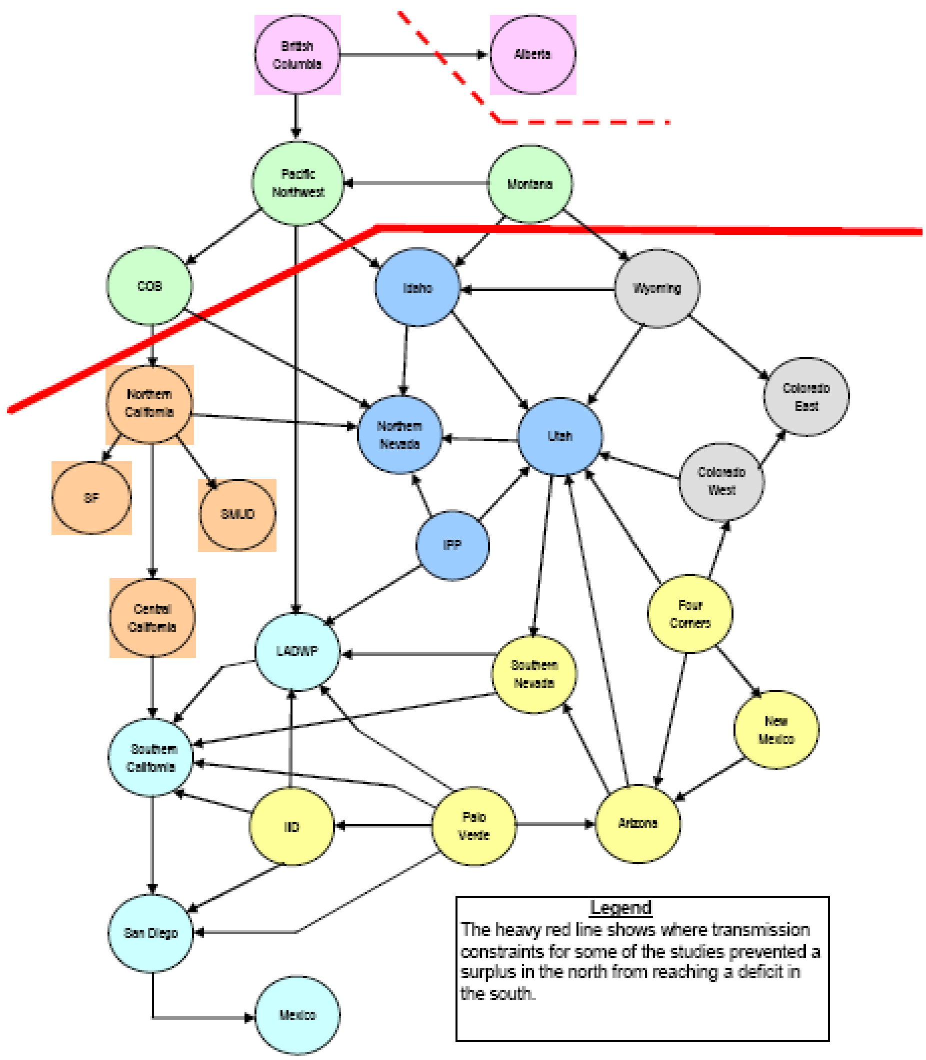


WECC's "2008 Power Supply Assessment"[8] indicates that, under certain assumptions, a condition called the "North-South Split" is observed, which happens when the transmission system between the northwest/British Columbia/Montana (the North) and the areas to the south (the South) is insufficient to allow all reported surpluses north of the constraint to meet loads south of the constraint in the economic dispatch performed in the assessment.

Those periods of the North-South Split manifestations are opportune times for surplus power from Colorado and others points to the east to be used to meet loads to the west. The following diagram in Figure 2-23 depicts the location of this split as it appears in the "2008 Power Supply Assessment."

[8] WECC, "2008 Power Supply Assessment," http://www.wecc.biz/planning/ResourceAdequacy/PSA/Pages/default.aspx

Figure 2-23. Western Electricity Coordinating Council's Transmission and North-South Split



Source: DOE, "National Electric Transmission Congestion Study." http://www.wecc.biz/planning/ResourceAdequacy/PSA/Pages/default.aspx

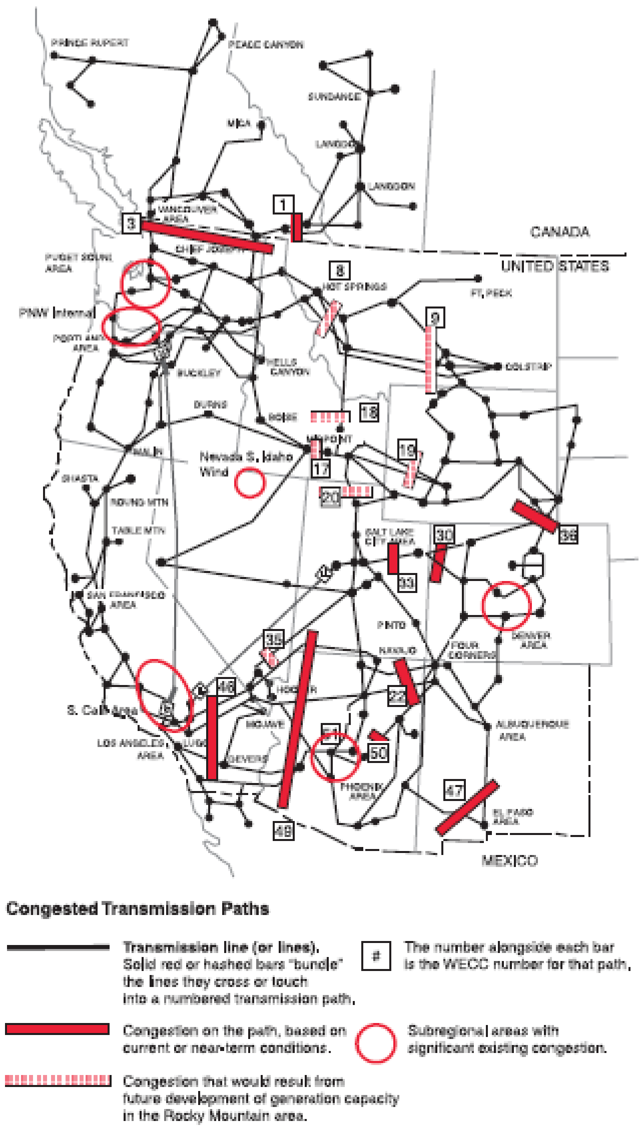
2.2.1 Export Paths for Colorado Power

The DOE's August 2006 "National Electric Transmission Congestion Study"[9] provides a historical perspective on transmission congestion in the WECC. Figure 2-24 displays some of the principal catalogued transmission paths in the WECC region and depicts those paths that were identified as congested in the historical studies.

[9] DOE, "National Electric Transmission Congestion Study," http://www.wecc.biz/planning/ResourceAdequacy/PSA/Pages/default.aspx

Tracing the paths from Colorado to the west, it can clearly be seen that there are potential major hurdles for export of electric energy from Colorado to points west (Colorado to Utah on paths 30, 33, and Colorado to Arizona and California on paths 22, 49, and 46).

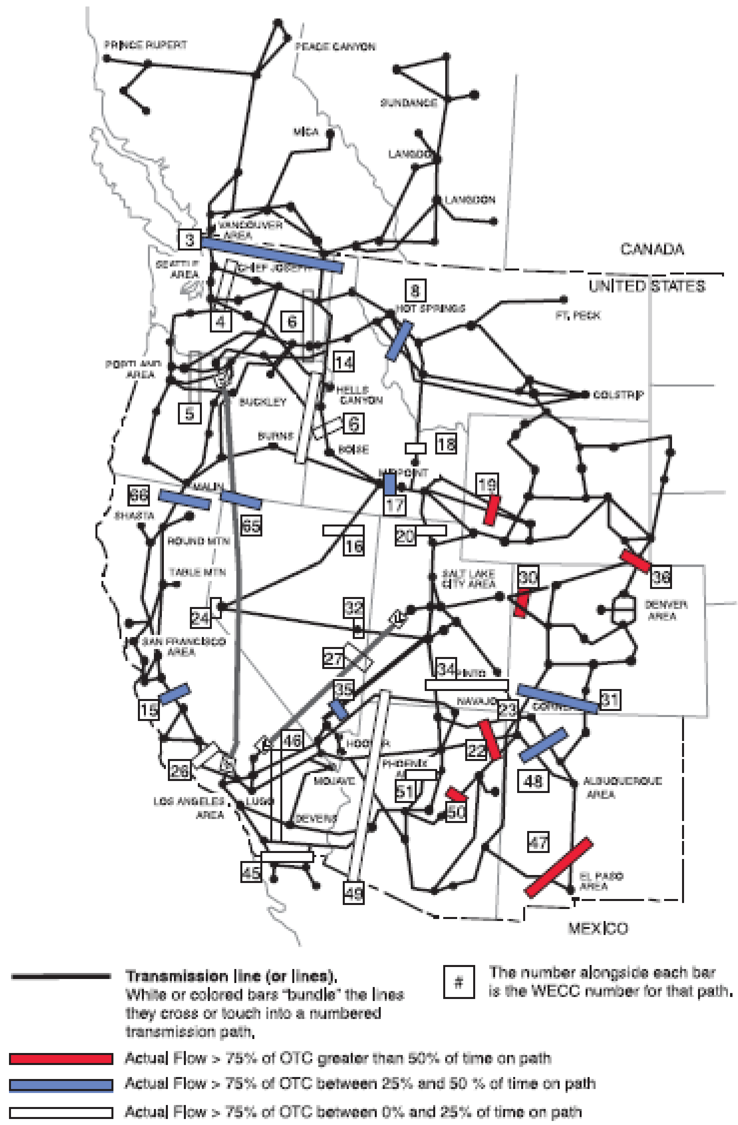
Figure 2-24. Congestion on Western Transmission Paths



Source: DOE, "National Electric Transmission Congestion Study."
http://www.wecc.biz/planning/ResourceAdequacy/PSA/Pages/default.aspx

Based on the same study, Figure 2-25 displays the western transmission paths that were most heavily used based on the examination of data on actual transmission usage for the six-year period between 1999 and 2005. The analysis is based on the most heavily loaded season for each path during the six-year period. Historically, paths 30 and 22 were shown to be highly congested. Path 31 from southwest Colorado to northeast Arizona was shown to be moderately congested. Paths 49 and 46 were shown to be lightly congested.

Figure 2-25. Actual Transmission Congestion, 1999-2005



Source: DOE, "National Electric Transmission Congestion Study."
http://www.wecc.biz/planning/ResourceAdequacy/PSA/Pages/default.aspx

In its western analysis, the DOE study sorted the congested paths by a number of methods to identify those that were most congested. The following paths were found to be the most likely to be the most heavily congested in 2008:

1. Arizona to southern Nevada and southern California.
2. Northern and eastern Arizona.

3. In the Rocky Mountains, the Bridger West line from Wyoming to Utah.
4. Montana to Washington and Oregon.
5. Colorado to Utah.
6. Colorado to New Mexico.
7. Utah to northern and central Nevada.
8. The Pacific Northwest south to California.
9. The Pacific Northwest flows northward to Canada.
10. In Southern California, from the Imperial Irrigation District to Southern California Edison.

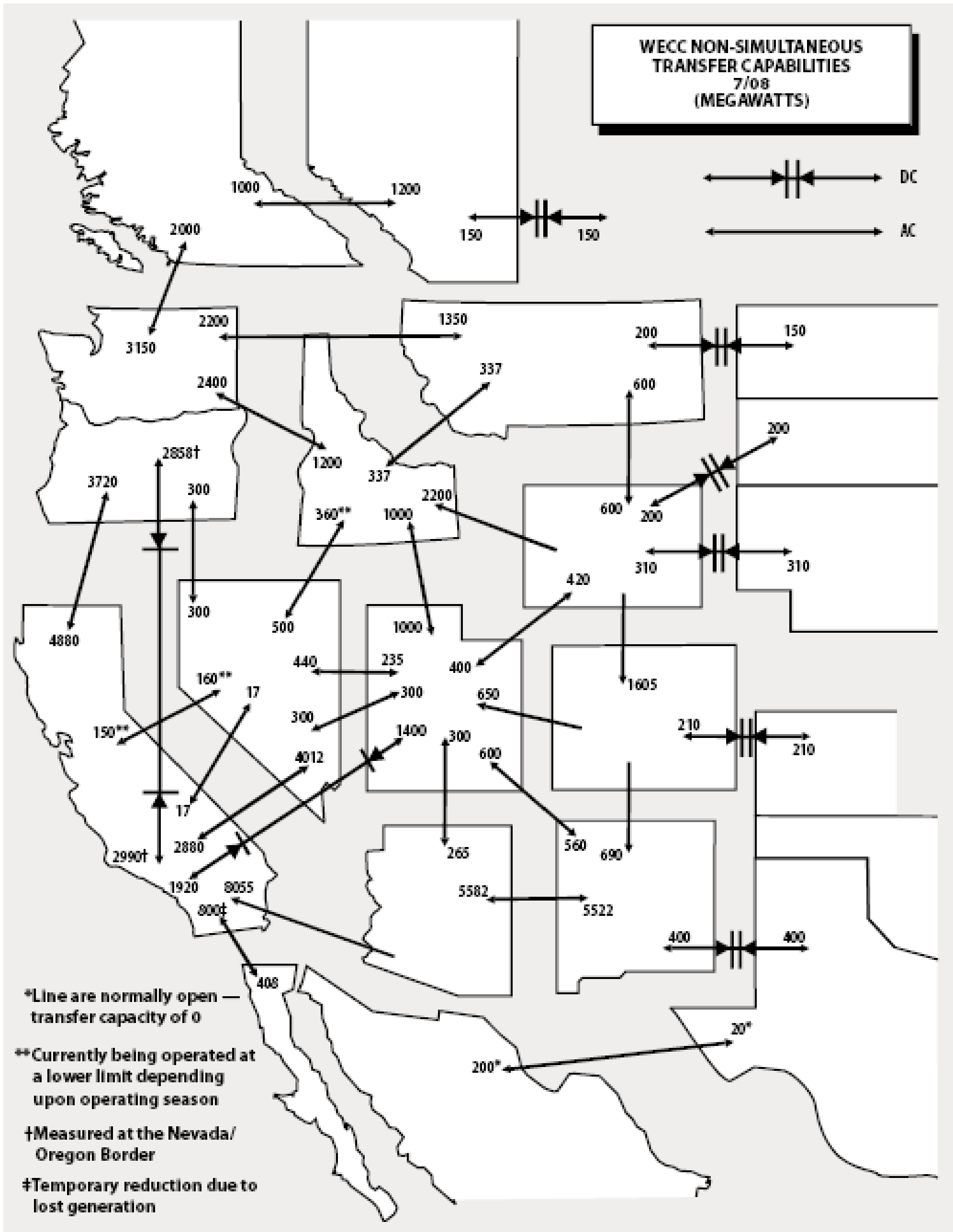
According to the study, these findings match with the results from other recent studies, as shown in the previous figures. Of the above identified paths, numbers 1, 3, 5, 6, 7, and 10 are the paths that have potential impact on the export of electric energy from Colorado to points west in the WECC.

The 2008 study by the WECC's Transmission Expansion Policy and Planning Committee (TEPPC) of so-called "2017 Cases,"[10] identified significant congestion, where the most heavily constrained paths included Path C (Utah-Idaho), TOT2A (Colorado-New Mexico), TOT2C (Utah-Nevada), the Four Corners 345/500-kilovolt (kV) transformers, and Montana-northwest. As can be seen, a number of these most heavily constrained paths are directly between Colorado and the potential export markets to the west.

Figure 2-26 shows the WECC's non-simultaneous transfer capabilities as of July 2008. As shown in the figure, the transfer capability from Colorado due south to New Mexico is 690 MW, and the transfer capability from Colorado due west to Utah is 650 MW. Therefore, the total non-simultaneous export capability from Colorado to south and west was about 1,340 MW as of July 2008.

[10] http://www.wecc.biz/documents/library/TEPPC/2009/CoverLetter_Exec_Summary_Final_V4_a.pdf

Figure 2-26. Western Electricity Coordinating Council's Non-Simultaneous Transfer Capabilities (July 2008)



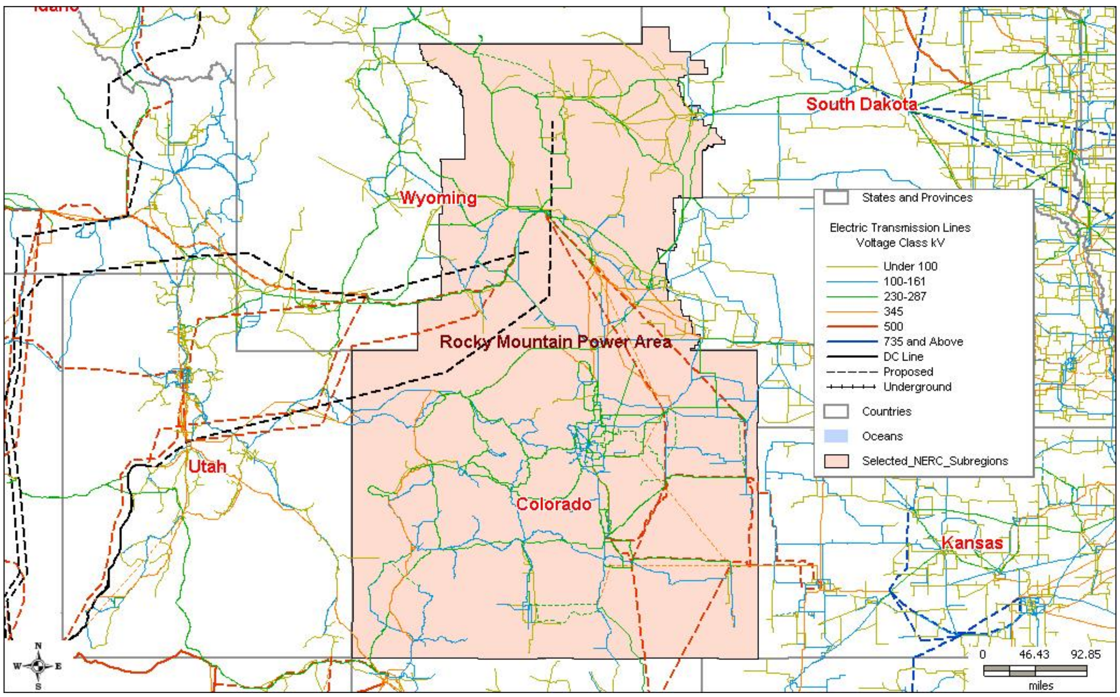
Source: WECC, "Information Summary," November 2008. http://www.wecc.biz/library

The above findings indicate that in order to facilitate the export of Colorado's electricity from renewable resources to other WECC states, in addition to the need for transmission infrastructure development within Colorado, significant work also needs to be done to address and mitigate constrained paths between Colorado and the markets to the west. Development of proposed major transmission projects in the WestConnect footprint is expected to increase the east to west transmission capacity.

2.2.2 Rocky Mountain Power Area Transmission Grid

Figure 2-27 takes a closer look at the transmission system within RMPA.

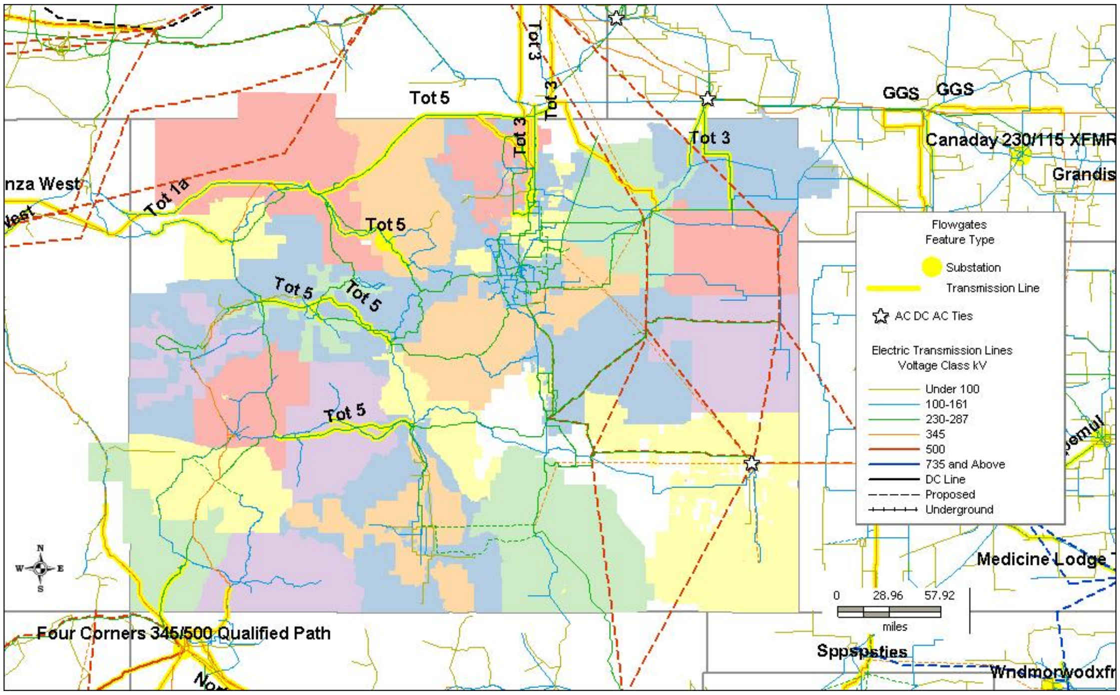
Figure 2-27. Rocky Mountain Power Area Transmission Grid



RMPA and Colorado are located on the eastern boundary of the WECC. To the east lies the Eastern Interconnection with no AC tie-lines to the west, therefore, the prospects for exporting of Colorado power to the east is minimal. The Tri-State Generation and Transmission Association (Tri-State) supplies wholesale electricity to WECC and Eastern Interconnection customers. Since 1977, Tri-State has owned and operated the David A. Hamil DC Tie at Stegall, Nebraska, which joins the Eastern and Western Interconnections. PSCo operates a DC tie to Lamar, Colorado, since 2005.

Figure 2-28 displays the transmission system in Colorado, with both existing and proposed transmission lines shown. Also shown are the locations of the major transmission constraints identified by yellow color lines (mostly referred to as TOTs, short for "TOTal power flows," as identified in WECC's annual Path Rating Catalogues).

Figure 2-28. Colorado Transmission Grid



2.2.3 RMPA Transmission Constraints

Table 2-1 lists the most relevant transmission paths, taken from the 2009 WECC "Path Rating Catalog,"[11] which would be expected to impact power flows within the Rocky Mountain region or between Colorado and its potential export markets to the west.

The paths and their transmission limits are defined over specific individual or collection of transmission lines. For reliability purposes, system operators in the WECC strive to ensure that these transfer limits are not violated by implementing various mitigation and remedial actions.

11 WECC, "Path Rating Catalog," January 2009.

Table 2-1. Western Electricity Coordinating Council's Transmission Paths with Impact on the Rocky Mountain Power Area

Path Name	Ratings
Path 19. Bridger West: Border between SE ID and SW WY	E to W: 2200 MW
Path 21. Arizona to California	E to W: 5700 MW (Non-simultaneous)
Path 22. Southwest of Four Corners	East-West: 2325 MW nominal, West-East: Not rated
Path 30. TOT 1A: Extreme NW CO	E to W: 650 MW (maximum)
Path 31. TOT 2A: Extreme SW CO	N to S: 690 MW minus net load in an area of SW CO
Path 36. TOT 3: Border between NE CO and SE WY	N to S: 1605 MW (Maximum)
Path 37. TOT 4A: SW WY	NE to SW: 810 MW (Non-simultaneous)
Path 38. TOT 4B: NW WY	SE to NW: 680 MW (Non-simultaneous)
Path 39. TOT 5: West-Central CO	W to E: 1675 MW
Path 40. TOT 7: North Central CO	N to S: 890 MW (maximum)
Path 46. West of Colorado River (WOR): NV-AZ to CA	10,623 MW
Path 48. Northern New Mexico (NM2): Northern NM	Simultaneous: 1849 MW Non-simultaneous: 1970 MW
Path 49. East of the Colorado River (EOR): Western AZ	E to W: 8055 MW (Non-simultaneous)
Path 80. Montana Southeast: Southeast MT	600 MW for both imports and exports from the MT
Phase II Projects	
II–4. Navajo Transmission Project, (segment 1): NE AZ and NW NM	E to W: 1600 MW
II-5. TOT3 Archer Interconnection Project: Border between NE CO and SE WY	N to S: 1800 MW
II-6. Wyoming-Colorado Intertie (WCI) Project: Eastern WY and NE CO	N to S: 900 MW
Phase III Projects	
III-1. Devers-Palo Verde #2 (DPV2) Path 49 Rating: Western Arizona	E to W: 9255 MW (Non-simultaneous)
III-2 East of the Colorado River 9300 MW Project: Western Arizona	E to W: Rating of 9300 MW
III-3 East of the Colorado River (EOR 9300 MW Prj)	E to W: Rating of 9300 MW
III-8. Path 36 Upgrade (Miracle Mile – Ault 230 kV): Border between NE CO and SE WY	N to S: 1680 MW (Maximum Proposed)

Source: WECC, 2009 "Path Rating Catalogue," January 2009.

NERC's "2008 Summer Reliability Assessment"[12] and "2008/2009 Winter Reliability Assessment,"[13] both indicate that the transmission path between southeastern Wyoming and Colorado often becomes heavily loaded, and consequently, the WECC's unscheduled flow mitigation procedure may have been invoked on occasion during the winter to provide line loading relief for these paths.

2.2.4 Planned Transmission Projects

As listed in NERC's "2008 Long-Term Reliability Assessment,"[14] and compiled in Table 2-2, there are a number of planned transmission projects in the WECC. Only those transmission projects greater than 200 kV in size are included in the table. Due to various project delays, some of the expected service dates may be pushed back.

12 http://www.nerc.com/files/summer2008.pdf

13 http://www.nerc.com/files/Winter2008-09.pdf

14 NERC, 2008 Long-Term Reliability Assessment, October 2008.

Table 2-2. Major Planned Northwest Transmission Projects

Terminal From Location	Terminal To Location	NERC Subregion	Line Length (Miles)	Voltage Operating (kV)	Capacity Rating (MVA)	Expected Service Date
Montana	Alberta	NWPP	80	230	TBD	May-09
Montana	Alberta	NWPP	135	230	TBD	May-09
Northwest Alberta Reinforcement		NWPP	83	144	330/422	Apr-10
Northwest Alberta Reinforcement		NWPP	145	240	TBD	Apr-10
Midpoint	Boise Bench: Loop King	NWPP	80	230	TBD	Jun-10
Populus	Terminal	NWPP	135	345	TBD	Jun-10
Gonder	Harry Allen	NWPP	250	525	3000	Jun-12
Northwest Alberta Reinforcement		NWPP	135	144	TBD	Apr-11
East Kootenay Reinforcement		NWPP	80	230	TBD	Oct-11
Edmonton	Calgary Transmission Reinforcement	NWPP	206	500	3000	Nov-11
Rock Springs, WY	American Falls, ID	NWPP	1041	500	TBD	Jun-12
Hemingway	Boardman	NWPP	202	500	3000	Jun-12
Mountain States Transmission Intertie		NWPP	460	500	1500	Jan-13
Pearl Transmission Station		NWPP	78	230	394	May-14
Shoshone, ID	Walters Ferry, ID	NWPP	126	500	3000	Jun-14
Nicola, BC	Meridian, BC	NWPP	153	500	TBD	Oct-14
Donkey Creek	Pumpkin Buttes	RMPA	75	230	TBD	Oct-08
Hughes	Sheridan	RMPA	105	230	460	Dec-09
Miracle Mile	Ault	RMPA	146	239	402	Dec-09
Comanche	Midway	RMPA	50	230	506	May-10
Comanche	Daniels Park	RMPA	125	345	1200	May-10
Comanche	Daniels Park	RMPA	125	345	1200	May-10
Midway	Waterton	RMPA	82	345	1200	Nov-10
San Luis Valley	Walsenburg	RMPA	80	230	613	Dec-11
RMPA	Pawnee Smoky Hill	RMPA	96	345	735	May-13
Southeast Valley Project		AZ/NM/SNV	51	500	1405	Jun-08
Navajo Transmission Project		AZ/NM/SNV	189	500	1300	Apr-09
Navajo Transmission Project		AZ/NM/SNV	62	500	1300	Dec-10
Southeast Valley Project		AZ/NM/SNV	87	500	1405	May-11
Centennial II Proejct		AZ/NM/SNV	61	525	3000	Jun-11
Navajo Transmission Project		AZ/NM/SNV	218	500	1300	Dec-11
Palo Verde	North Gila	AZ/NM/SNV	115	500	1200	Jun-12
Tortolita	Vail	AZ/NM/SNV	60	345	925	Jun-14
Metcalf	Moss Landing Reconducting	CA/MX	70	230	TBD	Dec-08
Big Creek 3	Rector	CA/MX	75	230	460	Apr-09
Palo Verde	Devers	CA/MX	225	500	TBD	Jun-11
IPPDC Upgrade		CA/MX	488	± 500	TBD	Jul-09
Sunrise Powerlink (IV-Central)		CA/MX	100	500	TBD	Jun-11
Barren Ridge	Castaic	CA/MX	72	230	TBD	Jul-05
Barren Ridge	Castaic	CA/MX	234	230	TBD	Jul-05
Green Path North		CA/MX	85	500	TBD	Nov-13
La Jovita, MX	La Herradura, MX	CA/MX	50	230	430	Oct-13
El Cañon, MX	El Ciprés, MX	CA/MX	52	230	430	Jun-15

Source: NERC, "2008 Long-Term Reliability Assessment,": October 2008.

According to the NERC report, in addition to the currently planned transmission projects, several proposed mega transmission projects ranging from 1,500 MW to 3,000 MW are in the early stages of consideration, including the following:

- Northern Lights – Celilo Project (Alberta to Oregon).
- Northern Lights – Inland Project (from as far north as Montana to as far south as Los Angeles and Phoenix).
- Frontier Line (from Montana and Wyoming to California).
- TransWest Express Project (from Wyoming to Arizona).
- Canada/Pacific Northwest to Northern California Project.

Most of these projects are associated with potential renewable energy projects and reinforce the transmission system. These projects are expected to help reduce future

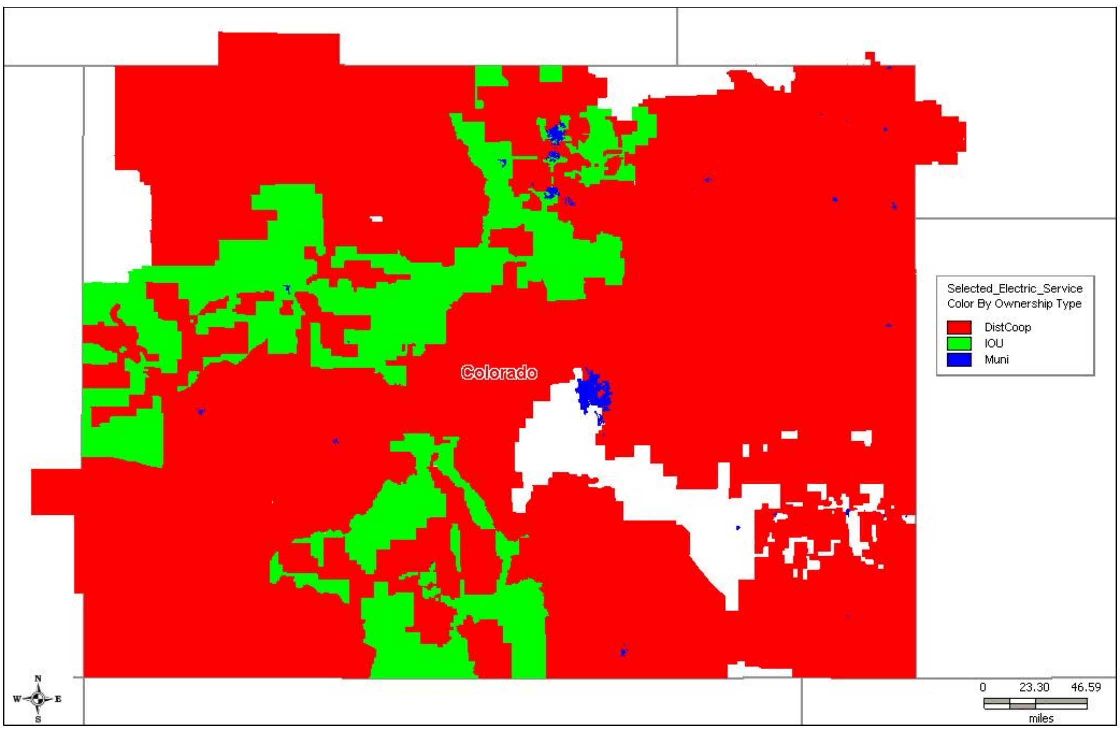
North-South transmission constraints such as the North-South Split. Some changes to the planned and proposed projects should always be expected.

Section 3
Colorado Market Entities

3.1 Types of Market Entities in Colorado

The Colorado electricity market consists of many different types of entities engaged in electric power generation, transmission, distribution, supply, and consumption of electricity. Figure 3-1 presents a map of the geographical extent of IOUs, Munis, and REAs (REAs are referred to as DistCoop in the map). Geographically, a vast extent of Colorado is served by REAs. However, most population centers are served by either IOUs or Munis.

Figure 3-1. Geographic Distribution of Different Colorado Utility Types



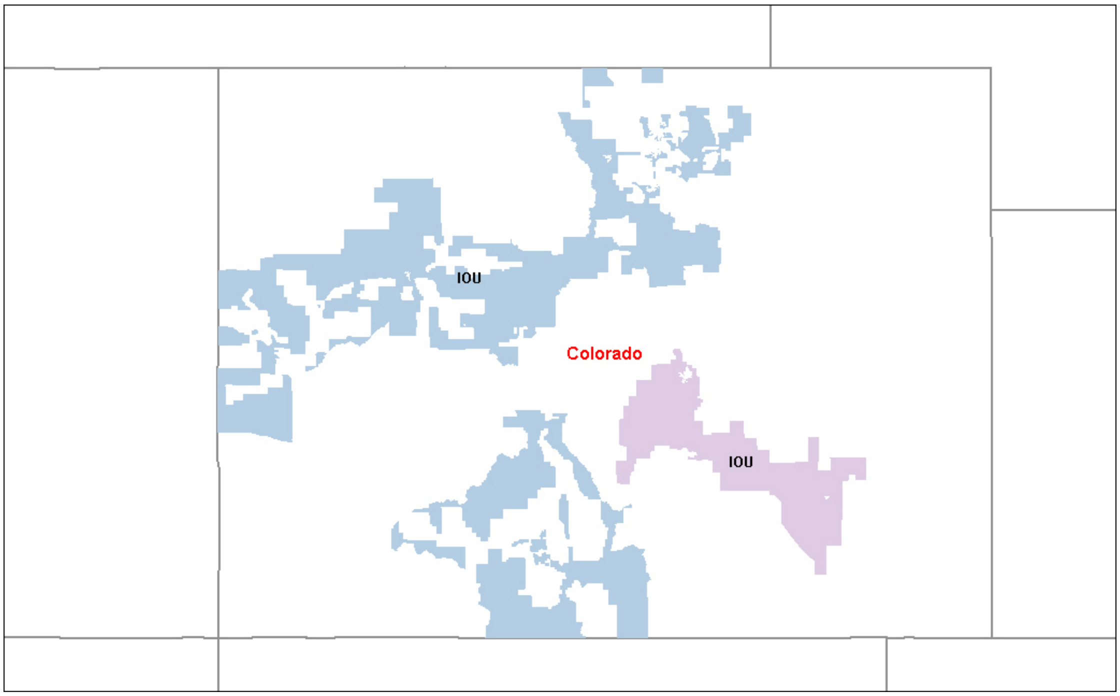
3.1.1 Retail Suppliers

Colorado retail electricity is supplied by IOUs, REAs, or Munis. Some of the retail suppliers also sell wholesale electricity.

Investor-Owned Utilities

The IOUs in Colorado include Xcel Energy's PSCo with about 2.5 million customers, and Black Hills Energy, operating in southeast Colorado, with about 92,000 customers. Figure 3-2 displays the geographic extent of Colorado's IOUs.

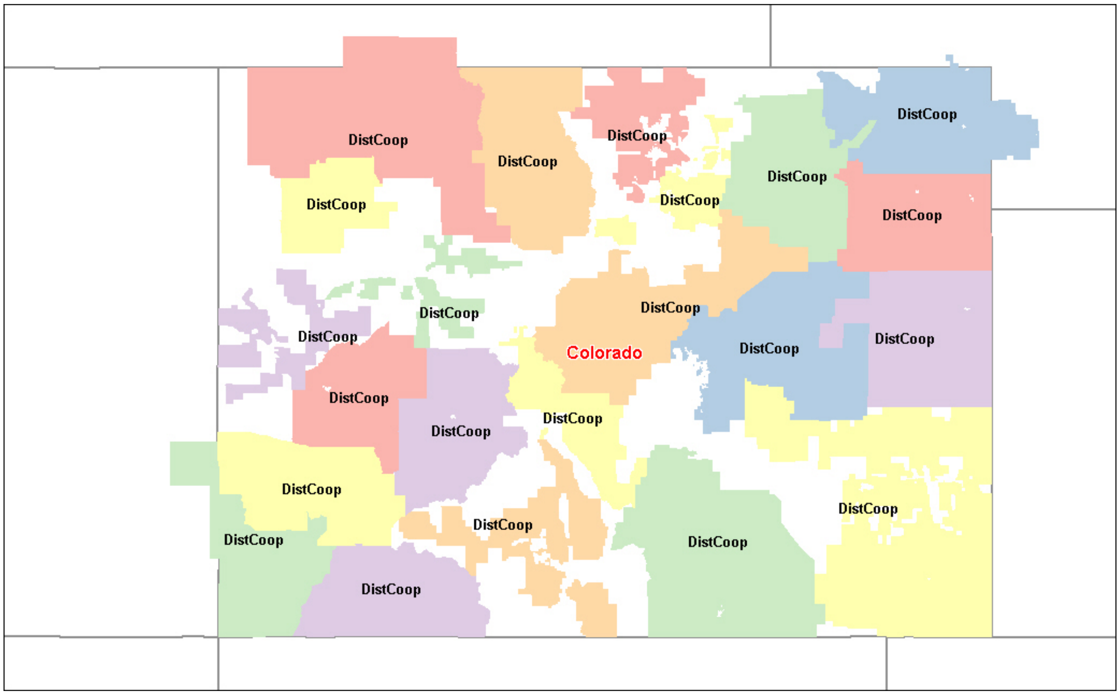
Figure 3-2. Geographical Extent of Colorado Independent System Operators



Rural Electric Associations

There are 22 REAs in Colorado, which are local distribution companies owned by their members. Of these, 18 are voting members of Tri-State, which supplies wholesale power to those members. The other four REAs purchase wholesale power from PSCo. Several REAs also purchase power from WAPA. Figure 3-3 presents the geographic extent of Colorado's REAs.

Figure 3-3. Geographical Extent of Colorado's Rural Electric Associations

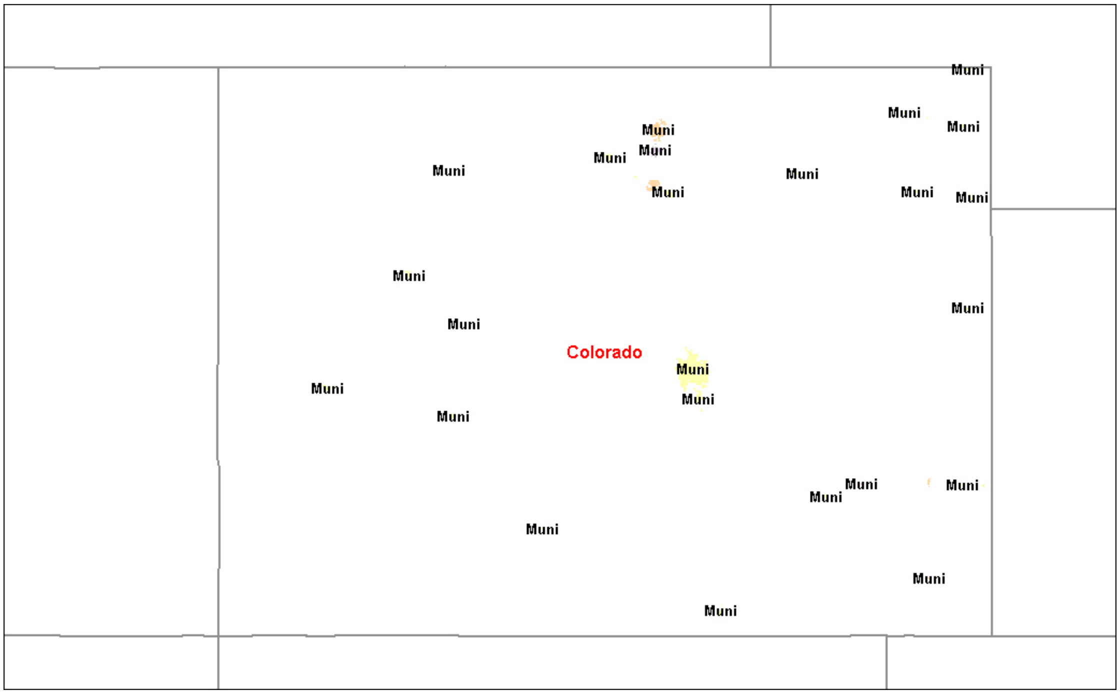


REAs are referred to as DistCoops.

Municipal Utilities

There are 29 Munis within Colorado, the largest of which is Colorado Springs Utilities with about 200,000 customers. The next largest is Fort Collins Utilities. Munis supply electrical service to about 19 percent of Colorado's customers. They purchase power from various wholesale power suppliers. Figure 3-4 presents the geographic extent of Colorado Munis. With few exceptions, Munis serve customers within their city boundaries.

Figure 3-4. Geographic Extent of Colorado Munis



3.1.2 Wholesale Suppliers

In addition to the retail suppliers discussed, there are other entities that sell power at the wholesale level to other utilities. These include PSCo, Tri-State, Arkansas River Power Authority, Platte River Power Authority, WAPA, and independent power producers.

Generation and Transmission Association

Tri-State is the only consumer-owned generation and transmission association operating in Colorado. It is a wholesale power supplier owned by 44 Co-ops in Colorado, Nebraska, New Mexico, and Wyoming. Tri-State has 18 members in Colorado. It is owned by its member REAs, to which it supplies wholesale power.

Municipal Joint Action Agencies

Municipal joint action agencies are a form of cooperative formed by member Munis. The two in operation in Colorado are Platte River Power Authority and Arkansas River Power Authority. They provide generation and transmission services to their respective municipal utility members. They are governed by boards of directors appointed by the member municipalities.

Federal Power Marketing Administrations

Three federal power marketing administrations were formed by the federal government to market the power from a multitude of federally owned hydroelectric power plants across the US. There are two administrations operating in WECC, Bonneville Power Administration and WAPA, and only WAPA operates in the Rocky Mountain region. However, its reach extends to 15 western states, with a footprint of over 1.3 million-square-miles. WAPA sells power and transmission services to a wide variety of wholesale customers, including Munis and REAs in Colorado. The National Environmental Policy Act of 1969 (NEPA), establishes policy and requirements for federal agencies with respect to protecting the environment. Therefore, siting of WAPA transmission is subject to NEPA review.

3.1.3 Other Independent Entities

Other independent entities engaged in electricity generation and transmission include merchant transmission companies, such as Trans-Elect Development Company, LLC, and independent power producers, exempt wholesale generators, and qualifying facilities, which are usually cogeneration heat and electricity producing facilities.

Table 3-1 provides a list of most (if not all) of principal entities by type, engaged in electricity generation, transmission, and distribution in Colorado.

Table 3-1. Principal Entities Engaged in Colorado Electricity Power Generation, Transmission, and Distribution

Colorado Utilities - Retail Suppliers		
	Investor Owned Utilities (IOUs)/Vertically Integrated Utilities:	
		Public Service Company of Colorado (PSCo), operating company of Xcel Energy
		Black Hills Energy, supplying 92,000 customers in Southeast Colorado
	Rural Electric Cooperatives or Rural Electric Associations	
		22 Rural Electric Associations (REA), mostly distribution companies owned by members
		18 purchase wholesale power from Tri-State Generation and Transmission Association
		4 purchase wholesale power from Xcel Energy
		Several also purchase power from Western Area Power Administration (WAPA)
	Municipal Utilities: Colorado Springs Utilities	
		29 Municipality-Owned Electric Utilities, largest are Colorado Springs and Fort Collins
		Munis supply 19% of Colorado electric customers
		Munis purchase power from various wholesales
Colorado Utilities - Wholesale Suppliers		
	Tri-State Generation and Transmission Association	
		Supplies power to its 18 member REAs
	Wholesale Municipal Generation and Transmission Associations (Municipal Joint Action Agencies)	
		Platte River Power Authority (PRPA)
		Arkansas River Power Authority (ARPA)
		They provide power to their member municipal electric systems
	Federal Power Marketing Administration: Western Area Power Administration (WAPA)	
		Serves 15 Western States, including REAs and Municipal Utilities in Colorado
	Public Service Company of Colorado (PSCo)	
		Sells to four REAs and to Black Hills Energy
Other Generation and Transmission Entities		
	Merchant Transmission (Trans-Elect Development Company, LLC)	
	Independent Power Producers	
	Exempt Wholesale Generators	
	Qualifying Facilities	

There are also many entities involved in shaping the business and regulation of the electric power industry. These entities include federal government organizations including FERC, which is responsible for interstate transmission regulation; NERC, which is responsible for enforcing reliability requirements of the transmission grid in the US; and state PUCs, which are responsible for regulation of in-state public utilities. As shown in Table 3-2, there are also other governmental and non-governmental entities that directly or indirectly have a hand in shaping the development of the electric power sector in Colorado.

Table 3-2. Other Entities that Influence Development of the Colorado Power Sector

Electricity Customers		
	Residential	
	Commercial	
	Industrial	
	Rural	
Regulators, Policy Makers, Policy Advocates		
	Federal and National Entities	
		Federal Energy Regulatory Commission (FERC)
		North American Reliability Corporation (NERC)
		US Department of Energy (DOE)
		US Department of Agriculture (USDA) - Rural Utilities Service (RUS)
	Colorado Government Entities	
		Colorado Legislator
		Colorado Department of Regulatory Agencies (DORA) - Public Utilities Commission (PUC)
		Colorado Governor's Energy Office (GEO)
		Colorado Clean Energy Development Agency (CEDA)
	Other Entities	
		Colorado Association of Municipal Utilities (CAMU)
		Western Interstate Energy Board (WIEB)
		Committee on Regional Electric Power Cooperation
		The Western Governors Association (WGA)
	Industry and Customer Associations and Advocates	
		The Interwest Energy Alliance
		American Wind Energy Association)
		Western Resource Advocates
		Rocky Mountain Farmers Union
		The Solar Alliance
Entities Responsible for Planning and Reliability		
	Utilities	
	Colorado Coordinated Planning Group (CCPG)	
		Colorado Long Range Transmission Planning Group (CLRTPG)
	Rocky Mountain Area Transmission Study (RMATS)	
	WestConnect	
	Western Electricity Coordinating Council (WECC)	
		Transmission Expansion Planning Policy Committee (TEPCC)
	FERC/NERC	

3.2 Regulation of Market Entities

Generally, interstate activities, those that cross state lines, are subject to federal regulation, while intrastate activities are subject to state regulation. Wholesale rates (sales and purchases between electric utilities), licensing of hydroelectric facilities, questions of nuclear safety and high-level nuclear waste disposal, and environmental regulation are all federal concerns.

In one way or another, all of the distribution utilities are regulated in Colorado. The two investor-owned utilities in Colorado are regulated as franchised natural monopolies by the Colorado PUC (CPUC), and serve about 60 percent of the retail customers in the state. The 29 Munis in Colorado are regulated by their local governing boards usually elected at the city and town level. The 22 REAs serve markets in Colorado and are also regulated by their member boards.

In Colorado, IOUs operate as regulated franchised natural monopolies, meaning that the prices they charge are subject to public review by the CPUC. Munis and REAs are nonprofits and are established to provide service to their communities at cost. Their rates are set by the Munis' city and town councils or utility board and REAs' member boards and therefore are not subject to CPUC review. The following sections provide an overview of the regulatory structure of various power sector entities in Colorado.[15]

3.2.1 Investor-Owned Utilities

Two IOUs provide electric service in Colorado: PSCo,[16] an operating company of Xcel Energy; and Black Hills Energy,[17] which serves southeast Colorado, mainly in the Pueblo area. Figure 3-5 presents an overview of the extent of PSCo's transmission system in Colorado. The IOUs in Colorado serve the majority of the customers in the state.

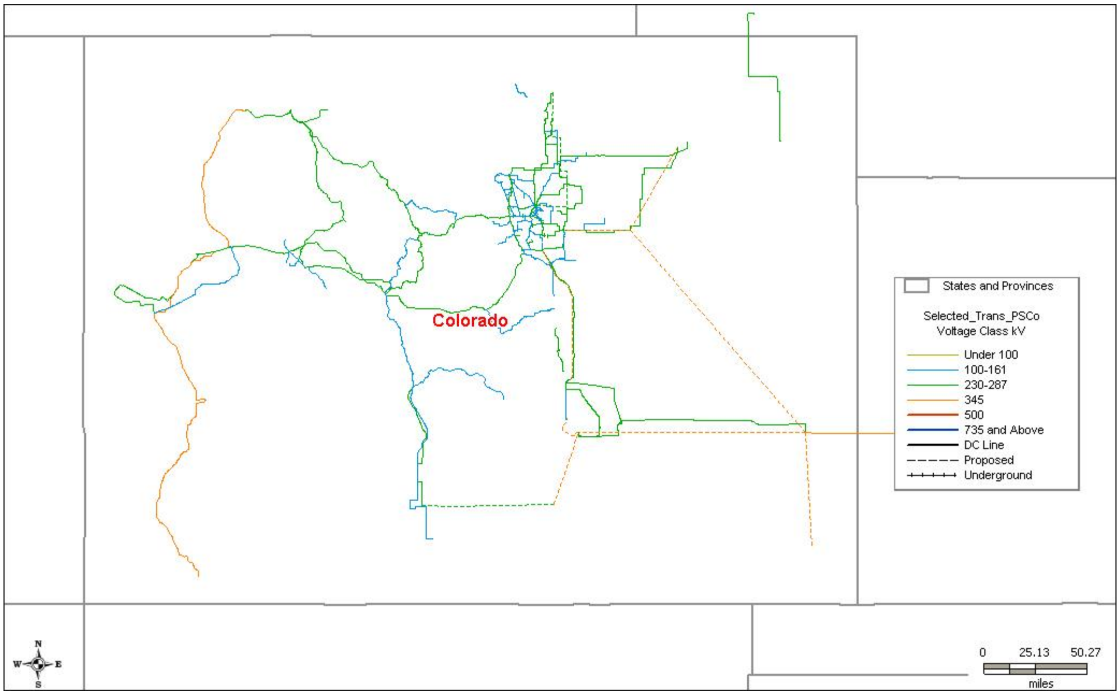
IOUs are given the exclusive right to operate in defined geographic footprint, and in return are regulated under the principle of franchised natural monopolies, with PUC regulating the IOUs' rates, services, and facilities. Since, in general, IOUs recover their costs plus a regulated rate of return on their generation and transmission assets, the PUC must approve the construction of new generating facilities and transmission lines proposed by IOUs. The PUC considers whether a facility is needed to serve customers and the costs are prudent before it approves a proposed facility.

[15] Colorado Energy Forum, "What Makes the Lights Go On? The Basics of Electricity in Colorado," April 2006. http://www.colorado.gov/energy/in/uploaded_pdf/Electricity_Basics.pdf

[16] http://www.xcelenergy.com/Company/Pages/Home.aspx

[17] http://www.blackhillsenergy.com/

Figure 3-5. Overview of Public Service Company of Colorado's Transmission in Colorado



3.2.2 Municipal Utilities

The question of whether the CPUC or the municipal governing bodies regulated the activities of Munis was decided by a series of Colorado Supreme Court decisions in the 1920s. These decisions gave the jurisdiction over rates charged for electricity within the municipal boundaries to the local governing boards, reasoning that the citizens can make a change to the governing board if they are not satisfied with the electricity rates.

The CPUC still had jurisdiction over the regulation of electric service of Munis outside of municipal boundaries, but in 1983, the Colorado General Assembly made a determination that the regulation of electric service by Munis was also with local governing boards unless there was a distinct difference between those rates and the rates within the municipal boundaries applied to similar class of customers.

However, for construction of new facilities outside the municipalities' boundaries, a Muni needs to file a Certificate of Public Convenience and Necessity (CPCN) with the CPUC and obtain CPUC's approval. Furthermore, the PUC can, on its own motion, or in responding to complaints by another utility, hear complaints concerning the duplication of facilities.

3.2.3 Rural Electric Associations

REAs range in size from the Intermountain REA[18] with a customer base of more than 120,000 customers to the White River REA with a customer base of about 3,000. The REAs were brought under PUC jurisdiction by the Colorado General Assembly in 1961 and regulated thereafter in a similar manner to those of IOUs. However, in 1985, Colorado legislators granted REAs the ability to request exemption from PUC regulation by a vote of their membership. All REAs initially voted for exemption from PUC regulation, but one REA, San Miguel Power Association, subsequently voted to be re-regulated by the PUC. San Miguel members voted at a later time to be exempt from PUC regulation. Currently, each REA's board of directors has the authority to establish rates for its customers. The PUC still has jurisdiction regarding certified service territories and in responding to complaints filed concerning rates, service, or securities.

3.2.4 Generation and Transmission Associations

Tri-State,[19] the only generation and transmission association operating in Colorado, is a wholesale electric power supplier serving its 44 REA members-owners, 18 of which are members located in Colorado. Tri-State was founded in 1952 by its members to provide a reliable, cost-based supply of electricity. Tri-State's service territory covers 250,000 square miles across Colorado, Nebraska, New Mexico, and Wyoming.

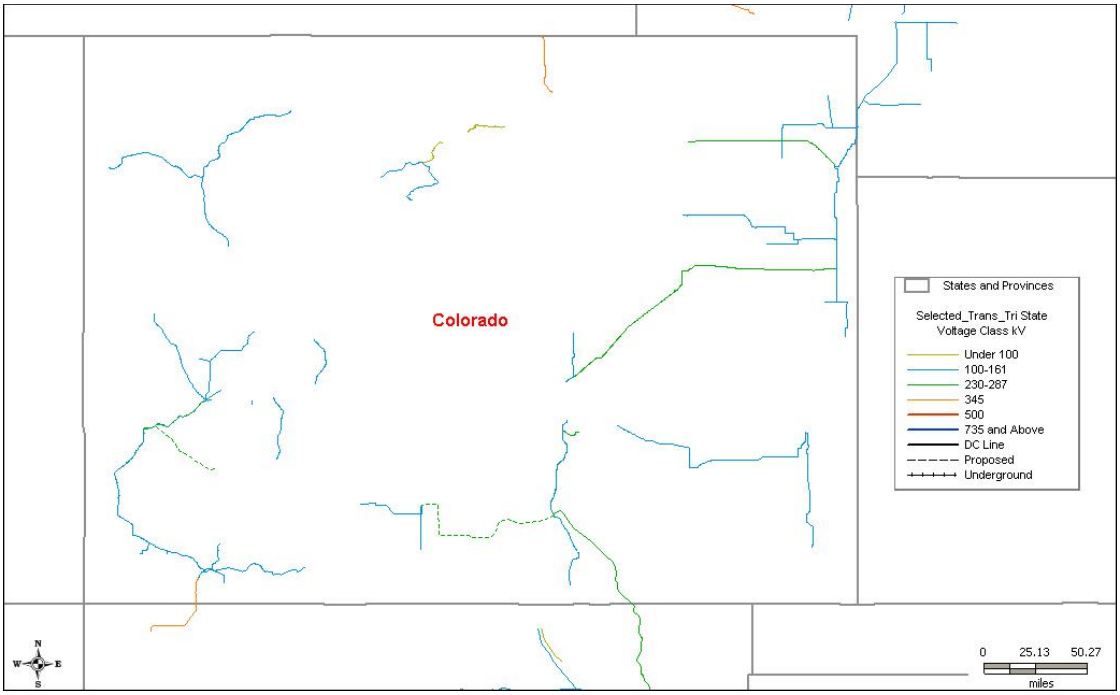
Tri-State has a generation portfolio of more than 3,000 MW, consisting of a combination of baseload and peaking power plants that use coal and natural gas as their primary fuels, supplemented by purchased power, federal hydroelectricity allocations, and renewable resource technologies. It also owns, either wholly or jointly, or has maintenance responsibilities for, more than 5,000 miles of transmission lines across Colorado, Nebraska, New Mexico, and Wyoming.

Tri-State has no retail customers; and since its wholesale customers are located in more than one state, its wholesale business is considered to be engaged in interstate commerce, and therefore, not subject to regulation by the PUC. However, Tri-State's facilities located in Colorado are subject to PUC jurisdiction, which requires the company to obtain a CPCN to construct major new generation and transmission facilities. Figure 3-6 presents an overview of the extent of Tri-State's transmission system in Colorado.

[18] http://www.intermountain-rea.com/

[19] http://www.tristate.coop/

Figure 3-6. Overview of Tri-State Generation and Transmission Administration in Colorado



3.2.5 Joint Action Agencies

Additions to the Colorado Constitution in 1994 granted the authority to Munis to act jointly for purposes of developing generation and transmission. The legislation on procedures for formation, governance, and financing of such authorities were enacted in 1975. Since then, a number of Munis have created "joint-action" power agencies in order to be able to pool their resources and benefit from economies of scale and have created or joined two such authorities in Colorado, namely, the Platte River Power Authority[20] and the Arkansas River Power Authority.[21] Each entity provides generation and transmission resources for its members through the construction and operation of these assets or contracts with other entities. In addition, several Colorado Munis are members of the Municipal Energy Agency of Nebraska,[22] which also provides wholesale electric supply and transmission services to its members. Municipal power authorities are self-regulated through a board of directors appointed

[20] http://www.prpa.org/

[21] http://www.arkansasriverpowerauthority.org/

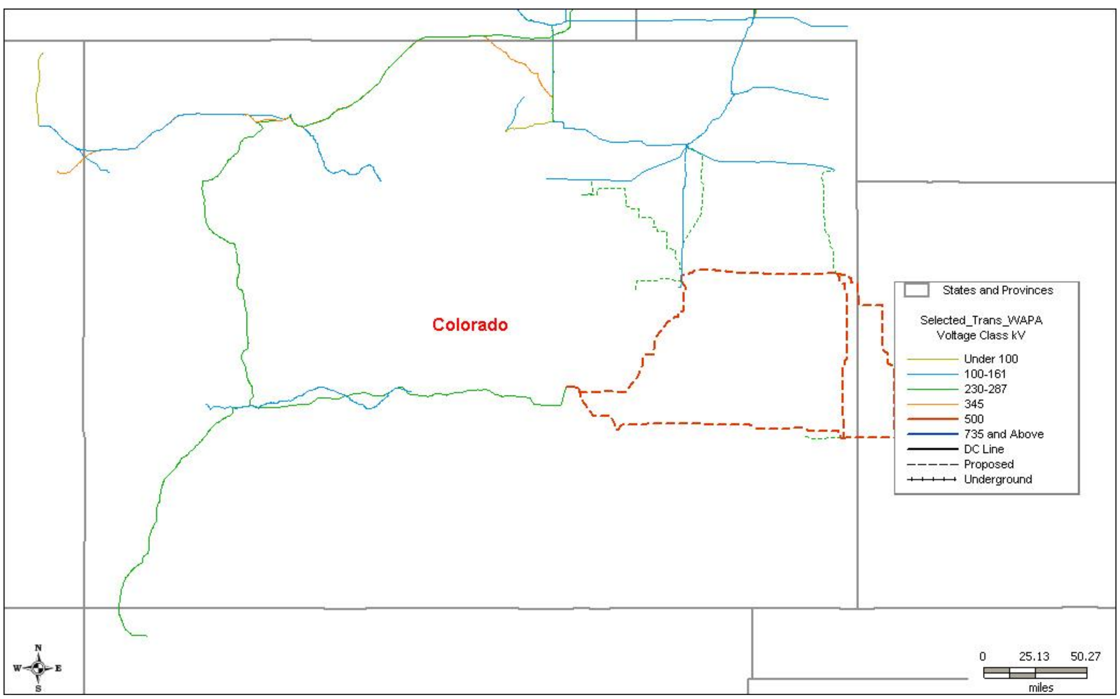
[22] http://www.nmppenergy.org/mean

by the member municipalities. Power authorities are not subject to PUC regulation and are subject to limited FERC jurisdiction.

3.2.6 Western Area Power Administration

WAPA[23] is one of the four federal power marketing administrations in the US administered by the DOE. Established by Congress in 1977, WAPA operates 56 hydroelectric power plants and one fossil-fueled power generation facility for a combined generating capacity of more than 9,000 MW. It also manages and maintains more than 17,000 miles of transmission lines. WAPA is a wholesale power provider to various IOUs, government-owned and cooperative utilities, power marketers, and other electricity organizations in 15 western states over a 1.3-million-square-mile service area. Many Munis and REAs in Colorado purchase wholesale power from WAPA. WAPA is not regulated by any state PUC or by FERC. Figure 3-7 presents an overview of the extent of WAPA's transmission system in Colorado.

Figure 3-7. Overview of Western Area Power Administration's Transmission in Colorado



3.2.7 Non-Utility Generators

Non-utility generators include independent power producers, exempt wholesale generators as defined by the Energy Policy Act of 1992, and qualifying facilities as

[23] http://www.wapa.gov/

defined by the Public Utility Regulatory Policy Act of 1978. These entities do not have defined service territories with retail customers. They sell power in the wholesale market or provide electricity and heat to industries. In general, non-utility generators are not regulated by the PUC or FERC, except that the status of a qualifying facility is certified by FERC.

The independent power producers have to deal with a few large wholesale power purchasers in the market, having to navigate across a fragmented territory under various regulatory jurisdictions.

Table 3-3 provides a summary overview of jurisdictional space of each type of market entities in Colorado.

Table 3-3. Regulatory Jurisdictions of Market Entities

IOUs	**G&T Association**
Jurisdiction: FERC/PUC	Jurisdiction: Members, PUC
Cost Recovery/Rates: FERC/PUC	Cost Recovery/Rates: RUS
Planning: PUC + Voluntary Coordination/Collaboration	Planning: Voluntary Coordination/Collaboration
Permitting: PUC, Local Authorities	Permitting: Local Authorities
Rural Cooperatives	**Municipal Power Authorities**
Jurisdiction: Members	Jurisdiction: Members
Cost Recovery/Rates: RUS	Cost Recovery/Rates: Governing Boards
Planning: RUS + Voluntary Coordination/Collaboration	Planning: Voluntary Coordination/Collaboration
Permitting: Local Authorities	Permitting: Local Authorities
Municipal Utilities	**Western Area Power Administration**
Jurisdiction: City Councils - Governing Boards	Jurisdiction: DOE
Cost Recovery/Rates: City Councils - Governing Boards	Cost Recovery/Rates: DOE - Cost Based
Planning: Voluntary Coordination/Collaboration	Planning: Voluntary Coordination/Collaboration
Permitting: Local Authorities	Permitting: None, with Local Input
Merchant Transmission	**Non-Utilities**
Jurisdiction: None	Jurisdiction: None
Cost Recovery/Rates: Market	Cost Recovery/Rates: Market
Planning: Voluntary Coordination/Collaboration	Planning: Voluntary Coordination/Collaboration
Permitting: PUC, Local Authorities	Permitting: PUC, with Local Authorities

3.2.8 Observations

As can be observed, the electricity market in Colorado is very fragmented in terms of types of entities and their regulatory jurisdictions. This is not uncommon in the WECC. An important distinguishing attribute is the mission, accountability, and ultimate client of each of these entities.

The Munis and REAs are responsible and accountable to their membership, which also constitute their service clients, and the members are in turn accountable to and are representatives of their service territory retail rate payers. It can be said that within their own realm, the shareholders of Munis and REAs are ultimately the same as their stakeholders.

WAPA is accountable to its federal overseers, but its service clients are wholesale customers in the state, so the distinction between shareholders (i.e., US government) and stakeholders (US government and wholesale customers) is not as clear cut, but it can be argued that the US government at the end is caretaker of the interests of wholesale customers, by requiring WAPA to provide its services at cost.

The IOUs, on the other hand, are ultimately responsible and accountable to their investor shareholders, but their service clients are their native retail rate payers in the state. It is this duality, or separation, of shareholders from other stakeholders that necessitates the PUC's oversight and authority over IOU rates and decisions.

Assuming that the ultimate stakeholders are the inhabitants of the state, not only is the Colorado electricity market fragmented in terms of the entities that generate, transmit, distribute, and supply power to ultimate rate payers, the rate payers themselves are fragmented in terms of channels of power and authority through which they can influence and initiate change.

The market fragmentation, with various exclusive territorial franchises and disparate regulatory jurisdictions, creates a static and resistant environment that may not be conducive to change. Furthermore, the insularity of the main players implies absence of competition and a level playing field, with regulatory and jurisdictional barriers to entry by independent entities, thus denying any potential benefits commonly ascribed to the invisible hand of competition. In fact, the Colorado electricity market is a combination of franchised natural monopoly providers and a collection of franchised monopsony buyers. However, a deeper understanding of the status of competition and identification of any visible or invisible barriers to competition and new entry, and any quantification of related market efficiencies or lack thereof, requires a separate detailed study.

This market fragmentation, on various levels, creates a potential for the missions, objectives, and interests of various players in the Colorado electricity market, not to be aligned with the interests of the ultimate stakeholders, namely the collective interests of all the Coloradoans taken together. Therefore, the objective of policy makers and all the stakeholders should be the development of policies, institutions, and approaches that help align various legitimate interests of all the market players in a direction that is of ultimate benefit to the people of Colorado.

4.1 Organizational Hierarchy

There are a number of state and regional organizations that provide a venue and a forum for Colorado utilities and other stakeholders to work together to plan and build the transmission infrastructure in the state. These organizations are engaged in long-term planning studies, mostly with a focus on system reliability and transmission capacity adequacy. The policy makers are interested in creating an environment with proper incentives that would be conducive to further development of transmission infrastructure required to better transmit generated renewable energy in the most efficient and cost-effective manner.

Colorado utilities currently participate in an open transmission planning process at the local, sub-regional, and regional levels. Colorado utilities coordinate their transmission planning with other transmission providers and stakeholders in the region through the Colorado Coordinated Planning Group (CCPG) and participation in WestConnect, membership in WECC, and participation in the WECC Transmission Expansion Planning Policy Committee and its Technical Advisory Subcommittee.

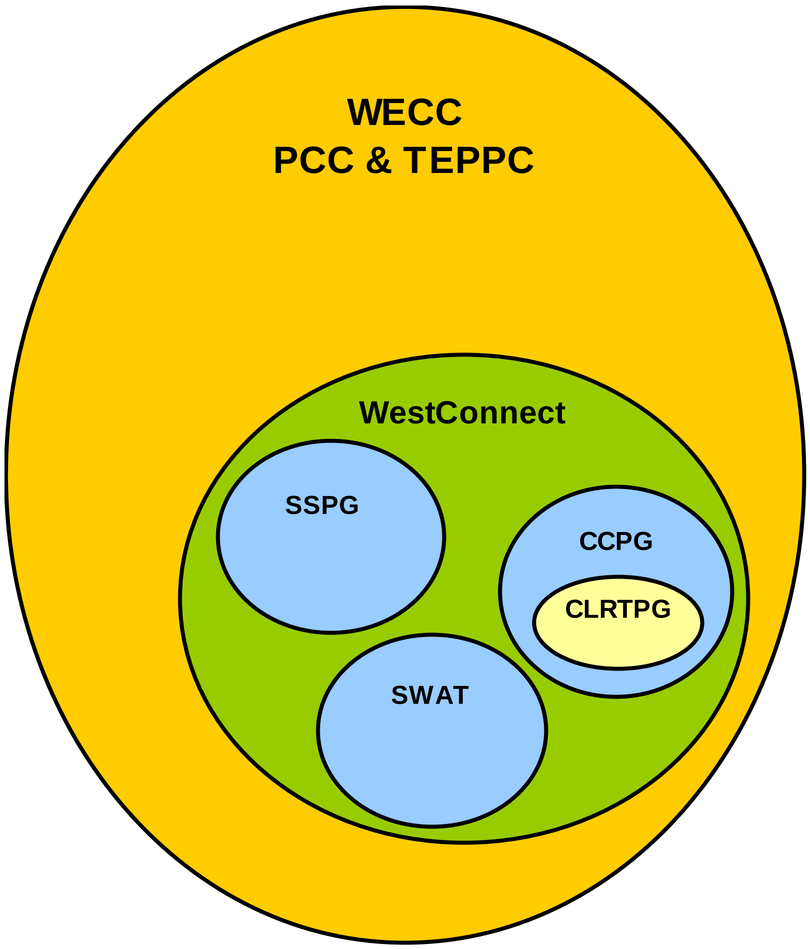
The overarching organization in the Western Interconnection is WECC, which has the overall responsibility for maintaining a reliable electric power in the west and assure open and non-discriminatory transmission access among its members. WECC's Planning Coordination Committee is responsible for oversight and review of the Regional Planning Review Process. WECC's Transmission Expansion Planning Policy Committee is charged with determining the need for economic expansion of the transmission system.

On the next level is WestConnect, which is a voluntary membership organization whose purpose is to work with other sub-regional organizations to investigate the feasibility of wholesale market enhancements. The sub-regional organizations responsible for their defined geographic areas are CCPG, Southwest Transmission Planning Group (SWAT), and Sierra Sub-regional Planning Group.

The sub-regional planning groups within the WestConnect footprint, assisted by the WestConnect planning manager, coordinate with other Western Interconnection transmission providers and their sub-regional planning groups through TEPPC. TEPPC provides for the development and maintenance of an economic transmission study database for the entire Western Interconnection region and performs annual congestion studies at the Western Interconnection region level.

The CCPG footprint covers all of Colorado and parts of Wyoming. A smaller sub-regional group is the Colorado Long Range Transmission Planning Group, which focuses on Colorado. Figure 4-1 displays the territorial relationship between these regional organizations.

Figure 4-1. Relationship of Regional Organizations



4.2 Western Electricity Coordinating Council

4.2.1 Overview

Western Systems Coordinating Council[24] was formed with the signing of the Western Systems Coordinating Council Agreement on August 14, 1967 by 40 electric power systems representing the electric power systems engaged in bulk power generation and/or transmission serving all or part of the 14 western states and British Columbia,

[24] www.wecc.biz

Canada. The WECC[25] was formed on April 18, 2002, as a Utah nonprofit corporation, by the merger of the Western Systems Coordinating Council, Southwest Regional Transmission Association, and Western Regional Transmission Association. Membership in WECC is voluntary and open to any organization having an interest in the reliability of interconnected system operation or coordinated planning.

WECC mission, as set forth in its bylaws,[26] are to:

- Maintain a reliable electric power system in the Western Interconnection region that supports efficient competitive power markets ("Reliability Mission"); and
- Assure open and non-discriminatory transmission access among Members and provide a forum for resolving transmission access disputes between Members consistent with FERC policies where alternative forums are unavailable or where the Members agree to resolve a dispute using the mechanism provided in Section 11 of the WECC's bylaws ("Transmission Access Mission").

The WECC region encompasses a vast area of nearly 1.8 million square miles extending from the western Canadian provinces of British Columbia and Alberta, covering all or portions of 14 western states in US, and down to the northern portion of the Baja California part of Mexico. It is the largest and most diverse of the eight regional councils of NERC. Transmission lines span long distances connecting the Pacific Northwest with its abundant hydroelectric resources to the arid southwest with its large coal-fired and nuclear resources.

WECC's mission of maintaining a reliable electric power system in the Western Interconnection and assuring open and nondiscriminatory transmission access among members is accomplished through WECC's 159 members. In addition to promoting a reliable electric power system in the Western Interconnection, WECC supports efficient competitive power markets, assures open and nondiscriminatory transmission access among members, provides a forum for resolving transmission access disputes, and provides an environment for coordinating the operating and planning activities of its members as set forth in the WECC's bylaws.

WECC's mission is to assure a reliable bulk electric power system in the Western Interconnection that supports efficient and competitive electric power markets. In carrying out this mission, WECC performs four organizational roles as follows:

- Regional Entity: WECC is required by FERC to monitor and enforce compliance with reliability standards by users, owners, and operators of the bulk power system in the United States.
- Credible Source of Interconnection-Wide Information: WECC provides training, education, and information on key functions related to mandatory standards and compliance, as well as data, analysis, and studies relating to transmission system planning, and renewable resource integration. WECC is a conduit for other data exchanges.

[25] See note 24.

[26] http://www.wecc.biz/documents/library/publications/WECC_Bylaws_2007.pdf

- Western Interconnection-Wide Planning Facilitator: WECC provides planning functions (transmission planning and integration of resources) and policy-related functions as requested by members.
- Western Interconnection-Wide Regional Reliability Policy Facilitator: WECC facilitates the identification of issues specific to reliability, creates an opportunity for discussion of the issues, and represents region-wide issues and policies at the state and federal levels.

4.2.2 Western Electricity Coordinating Council's Coordination of Regional Planning Activities

WECC's responsibilities with respect to regional planning and the coordination of relationships with those entities in the Western Interconnection that perform regional planning are defined in WECC's bylaws. Based on these bylaws, WECC is responsible for developing coordinated regional planning processes and procedures, including the facilitation of market-based solutions. The regional entities such as CCPG would perform regional planning using the regional planning processes and procedures established by WECC. WECC is responsible for reviewing and assessing the planning processes used by regional entities (i.e., CCPG) to determine whether WECC planning procedures have been satisfied. CCPG, and not WECC, would perform regional expansion studies, but WECC may perform other interconnection-wide studies as needed.

WECC's regional planning process is documented in the publication entitled "Procedures for Regional Planning Project Review and Rating Transmission Facilities."[27] The key aspects of WECC's planning process are their:

- Regional Planning Project Review: This is a process intended to inform others of the opportunity to participate in, or review, a project and to solicit participation. It is intended to avoid duplicate projects and allow a new project to integrate the needs of others by mutual agreement.
- Project Rating Review: This is a process intended to ensure that new projects are integrated into the existing system with a rating while recognizing protected ratings of other facilities.
- Progress Reports: A process by which project sponsors report potential significant additions and changes to the interconnected system and WECC members are provided the opportunity to review and comment on these additions or changes.

WECC's Planning Coordination Committee has the responsibility for the oversight and review of the Regional Planning Review Process.

Projects, which have significant regional impacts, are responsible for demonstrating their conformity with the WECC Regional Planning Guidelines[28], in addition to

[27] http://www.wecc.biz/documents/2005/PCC%20Meetings/Policies_Procedures_01-19-05_version_clean_v1.pdf

complying with the reliability and transmission rating review process. Foster the development of a broad regional planning perspective among all stakeholders in the planning process.

WECC develops the Western Interconnection-wide databases for transmission planning analysis such as power flow, stability, and dynamic voltage stability studies. WECC also maintains a database for reporting the status of all planned projects throughout the Western Interconnection. WECC provides for coordination of planned projects through its Procedures for Regional Planning Project Review. WECC's path-rating process ensures that a new project will have no adverse effect on existing projects.

4.2.3 Other Functions Performed by WECC

There are many other functions performed by WECC. The following summaries are based on WECC[29] descriptions of these functions.

Resource Adequacy

WECC's load and resource adequacy activities, including basic data collection, are performed largely under the auspices of the Loads and Resources Subcommittee of the Planning Coordination Committee. The load and resource data is used by the committee to perform annual resource adequacy studies, looking both at the WECC-wide and sub-regional levels.

The data and some studies are also provided to NERC for their resource adequacy assessment activities. WECC also develops The Power Supply Assessment and the Long-Term Reliability Assessment Report for NERC, which uses this report as input to its own continent-level report of the same name. The Loads and Resources Subcommittee data is also used by TEPPC to perform transmission expansion studies. Some of this data is used by WECC's Technical Studies Subcommittee, again along with additional specialized data, in developing transmission base cases and the operating and planning adequacy studies done with those cases.

Renewable Resource Integration

WECC is studying the regional reliability impacts of the increasing amount of renewable energy being added in the Western Interconnection. A desired outcome is to form a regional understanding of renewable energy in the Western Interconnection. The regional viewpoint on these emerging issues will provide decision support for standards, business practices, and policies concerning renewable energy. The renewable integration effort is currently engaged on a number of fronts, with a main effort to update, specify, and organize the renewable data in the transmission expansion planning process. In addition, the Variable Generation Subcommittee has been formed to aggregate member concerns, define WECC study activities, and report

[28] WECC, "Overview of Policies and Procedures for Regional Planning, Project Review, Project Rating Review, and Progress Report," April 2005.
[29] http://www.wecc.biz

results. Lastly, WECC is participating in sub-regional and national renewable integration efforts that will complement regional goals.

Regional and Continental Reliability Standards

Under the Energy Policy Act of 2005 and WECC's FERC-approved delegation agreement with NERC, WECC has the authority to create Regional Reliability Standards. These standards are enforceable on all entities operating in the US portion of the Western Interconnection. Compliance with these standards is also expected of WECC members in Canada and Mexico.

As of October 2008, eight Regional Reliability Standards are in place. These eight standards will be superseded upon regulatory approval of seven new Regional Reliability Standards that were approved by the WECC Board in April 2008. A Regional Reliability Standard on automatic time error correction is also pending before FERC. Standards developed by NERC are enforceable throughout the continental US and compliance is expected by entities in Canada and Mexico.

Compliance Monitoring and Enforcement Program

The Energy Policy Act of 2005 established a program of mandatory compliance with approved reliability standards in the US. The act directed the creation of an ERO that would delegate authority for compliance monitoring and enforcement to recognized Regional Entities. In 2006, FERC designated NERC as the ERO and WECC as one of eight regional entities. In 2007, FERC approved a set of reliability standards with which users of the bulk electric system are required to comply. These standards became mandatory on June 18, 2007. Under WECC's Compliance Monitoring and Enforcement Program, compliance is monitored through a combination of eight monitoring methods: audits, self certification, spot checking, investigations, self-reporting, periodic data submittals, exception reports, and complaints. WECC has become aware of possible violations primarily through self-reporting.

Each violation of a standard requires the submittal of a plan to mitigate the violation. These mitigation plans are reviewed and tracked by their Compliance Department to ensure that they are adequate and completely implemented. WECC's Compliance Monitoring and Enforcement Program has developed rapidly from start-up to a functioning program covering the entire range of compliance activities: registration, compliance monitoring, investigations, hearings, and outreach and education. It monitors compliance with standards for more than 450 entities in the Western Interconnection. The Compliance Department is now an independent function within WECC, headed by a vice president who reports directly to WECC's CEO. WECC's outreach programs, including the development of the Compliance User Group and the holding of "open mic" conference calls to address compliance questions, have become models for other regions. WECC supports the Western Interconnection Compliance Forum.[30] The guiding principles of WECC's Compliance Monitoring and Enforcement Program are: fairness and transparency (both within WECC and across

[30] www.wicf.biz

the NERC regions), sanctions and penalties that improve reliability, and professionalism and subject matter expertise. The overarching goal of WECC's compliance program is to bring about measurable improvement in the reliability of the Western Interconnection. By working together with Registered Entities, that goal is being realized as relay maintenance improves, vegetation is better managed, and standards are refined.

Transmission Service Obligations

As WECC's bylaws indicate, those members whose transmission capacity is controlled or operated by an RTO are assumed to be in compliance with the non-discriminatory transmission access provisions of FERC and WECC bylaws. Those not covered by being in an RTO are required to submit an OATT to FERC or provide access to other members in a non-discriminatory manner in accordance with WECC bylaws.

4.3 Transmission Expansion Planning Policy Committee

WECC's Transmission Expansion Planning Policy Committee[31] is charged with assisting the WECC region in determining the need for economic expansion of the transmission system, by providing impartial and reliable data, public process leadership, and analytic tools and services.

TEPPC manages a transmission economic planning database used for congestion cost studies, which includes information regarding load, transmission, fuel price, existing generation, and planned generation. WECC staff uses this database to simulate western regional production costs under various loads, gas prices, hydro, and other scenarios.

These activities are intended to result in a comprehensive, current, and well-validated database that can be readily used to identify where transmission expansion may be needed. The database can be used to evaluate the ability of transmission, generation, and demand-side resources to satisfy needs across the Western Interconnection.

In addition to database management, WECC (through TEPPC) conducts an annual study program, provides a policy forum and management of the transmission planning process, and guides the analysis and economic modeling for Western Interconnection transmission expansion planning.

TEPPC and its subgroups work closely and coordinate with western state, provincial, and federal government entities. TEPPC also conducts studies on congestion for the DOE.

[31] http://www.wecc.biz/documents/library/publications/infosum/2008%20Infosum.pdf

http://www.wecc.biz/documents/library/TEPPC/2009/CoverLetter_Exec_Summary_Final_V4_a.pdf
(Materials in this section are based on the above sources, among others)

TEPPC's three main functions include:

- Overseeing database management.
- Providing policy and management of the planning process.
- Guiding the analyses and modeling for Western Interconnection's economic transmission expansion planning.

These functions complement, but do not replace, the responsibilities of WECC's members and stakeholders to develop and implement specific expansion projects.

TEPPC uses publicly available data to compile a database that can be used by a number of economic congestion study tools. TEPPC's database is publicly available for use in running economic congestion studies. For an interested transmission customer or stakeholder to utilize WECC's PROMOD™ planning model, it must comply with WECC confidentiality requirements.

TEPPC has an annual study cycle during which it will:

- Update databases.
- Develop and approve a study plan that includes studying transmission customer's high priority economic study requests as determined by the open TEPPC stakeholder process.
- Perform the approved studies and document the results in a report.

TEPPC provides a good stakeholder input process through diverse TEPPC membership and open participation in the Technical Advisory Subcommittee.

Each year, TEPPC prepares a Synchronized Study Plan to meet its goal of providing economic expansion information to its constituents that identifies future transmission needs in the Western Interconnection region and is useful in the conception and design of new transmission projects to meet those needs.

The 2008 Annual Report of the Transmission Expansion Policy Subcommittee describes the activities and results achieved under the 2008 Study Plan. In its Transmission Planning Protocol, TEPPC adopted an adaptive study cycle that is designed to applying lessons learned to adjust and guide future activities.

The 2009 Study Plan will be developed using the 2008 studies as a foundation, and study efforts will expand to meet the rapidly growing demand for greater integration of transmission planning and to meet anticipated federal transmission planning initiatives.

As noted earlier, TEPPC's 2008 study of so-called "2017 Cases"[32] identified significant congestion where the most heavily constrained paths included Path C (Utah-Idaho), TOT2A (Colorado-New Mexico), TOT2C (Utah-Nevada), the Four Corners 345/500-kV transformers, and Montana-Northwest. A number of these most heavily constrained paths are directly between Colorado and the potential export markets to the west.

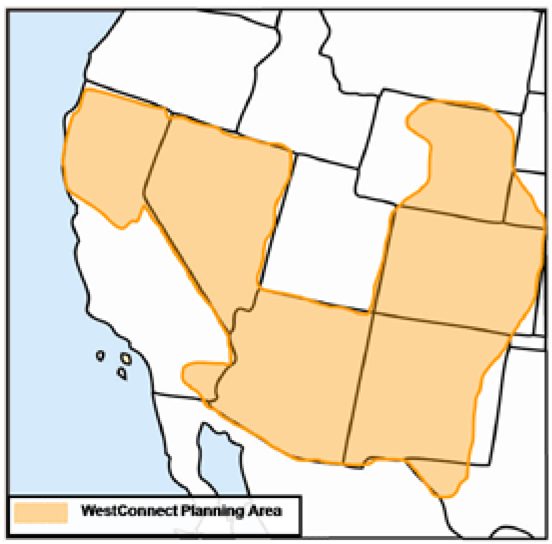
[32] http://www.wecc.biz/documents/library/TEPPC/2009/CoverLetter_Exec_Summary_Final_V4_a.pdf

4.4 WestConnect

WestConnect[33] was formed by electric utility companies providing transmission services throughout the southwestern US. WestConnect membership is voluntary. The purposes of WestConnect are to investigate the feasibility of wholesale market enhancements, work cooperatively with other Western Interconnection organizations and market shareholders, and address seams issues in the appropriate forums. Its members work collaboratively to assess stakeholder and market needs and to develop cost-effective enhancements to the western wholesale electricity market.

Figure 4-2 displays the current WestConnect planning footprint, which encompasses all or portions of seven western states--Arizona, California, Colorado, New Mexico, Nevada, Texas, and Wyoming.

Figure 4-2. WestConnect Areas



Source: www.westconnect.com

A WestConnect Steering Committee is charged with the task of overseeing the development and implementation of a variety of initiates on behalf of the WestConnect members.

4.4.1 WestConnect's Role in Regional Planning

WestConnect initiated an effort to facilitate and coordinate regional transmission planning across the WestConnect footprint by formation of a regional transmission planning function. The WestConnect Planning Objectives and Procedures for

[33] www.westconnect.biz

Regional Planning was approved on August 25, 2006. In May 2007, 12 transmission providers signed a WestConnect Project Agreement for Sub-regional Transmission Planning (STP Agreement).[34] By 2008, three more transmission providers signed the STP Agreement bringing the total member count to 15.

The current WestConnect Planning Management Committee members include:

- Arizona Public Service.
- Basin Electric Power Cooperative.
- Black Hills Energy.
- El Paso Electric.
- Imperial Irrigation District.
- Nevada Power Company/Sierra Pacific Resources.
- Public Service Company of New Mexico.
- Sacramento Municipal Utility District.
- Salt River Project.
- Southwest Transmission Cooperative.
- Transmission Agency of Northern California.
- Tri-State.
- Tucson Electric Power Company.
- WAPA.
- Xcel Energy/PSCo.

Colorado's two IOUs (PSCo and Black Hills Energy) and also Tri-State and WAPA are members of WestConnect. Therefore, practically most of Colorado's transmission is within the WestConnect territory.

The STP Agreement establishes a formal commitment of the signatory parties to fund and oversee the WestConnect sub-regional planning process. The WestConnect STP Agreement also established a Planning Management Committee made up of one representative of each of the signatory parties. The Planning Management Committee is tasked with implementation of a sub-regional planning process that complies with WestConnect's Planning Objectives and Procedures for Regional Planning.

The Planning Management Committee has the authority to enter into contracts with individuals or firms for provision of project management, report writing, transmission planning, and secretarial/communications services to the CCPG, SWAT, and Sierra Sub-regional Planning Group, and any other sub-regional transmission planning group efforts that form the WestConnect planning area. The sub-regional transmission planning is performed by these regional transmission planning groups. Annually, a 10-year integrated regional transmission plan is derived from their efforts that

[34] http://www.westconnect.com/planning.php

coordinate all transmission plans across the WestConnect planning area. On May 23, 2007, K. R. Saline and Associates was hired as an independent contractor for the purpose of managing the WestConnect planning process and providing the above-stated contracted services. As part of the annual transmission plan, WestConnect conducts a 5th and 10th year adequacy study to determine the adequacy of the WestConnect Ten Year Transmission Plan for a near-term planning horizon and a long-term planning horizon.[35]

4.4.2 Principles for Sub-regional Transmission Planning

To enhance the regional transmission planning and coordination efforts of electric utilities and other entities in the Rocky Mountain sub-region and the Desert Southwest sub-region, the WestConnect parties, SWAT and CCPG, have developed the following principles for coordinating transmission planning of the entire WestConnect footprint.[36] Presently, the two sub-regional transmission planning groups (SWAT and CCPG) provide the coordinated planning forums for each of their respective sub-regions and collectively cover the entire WestConnect area.

Since the SWAT and CCPG sub-regional planning groups were established independently by different forces, principles and membership, it is reasonable that the sub-regional planning organizations continue to conduct focused planning efforts for their sub-regions. Additionally, coordination of their sub-regional efforts will bring benefits to WestConnect and all other utilities and entities through representation of a larger region. For this reason, the following principles for coordination of sub-regional transmission planning have been developed.

In support of the WestConnect transmission planning goals, SWAT and CCPG agree to:

- Conduct a biennial near- and long-term transmission system plan in accordance with NERC/WECC planning criteria.
- Provide input for WestConnect to produce a single near and long-term transmission plan/document that addresses all the transmission needs across the entire WestConnect footprint.
- Coordinate efforts such that the transmission plans of each sub-regional group are developed on the same cycle.
- Coordinate base case development for the WestConnect region.
- Commit to coordinate and share information regarding planning efforts between CCPG and SWAT, and subsequently with WestConnect.

[35] http://www.westconnect.com/filestorage/CCPG_032508_Notes_Final.doc
[36] http://www.westconnect.com/filestorage/WestConnect-SWAT%20-%20CCPG%20Transmission%20Planning%20Principles%20Final%20-%20FEB%2026%2020061.pdf

- Maintain individual sub-regional planning processes and procedures, but ensure no redundancies occur in the WestConnect footprint.
- Where appropriate, develop coordinated transmission plans.

4.4.3 WestConnect Initiatives

In addition to coordination of regional transmission planning, WestConnect has undertaken other initiatives to facilitate coordinated and efficient operation of the transmission grid in the WestConnect territory. The following summaries are based on descriptions of initiatives by WestConnect.[37]

WestConnect Flow-Based Market Investigation

Utilities in the Western Interconnection have traditionally allocated contract path rights for the use of the transmission systems they own or operate. These rights are defined based on the specific facilities over which energy is assumed to flow.

By way of contrast, the actual flow on the system is dictated by the physical characteristics of the transmission system and not the contract. This leads to a mismatch between the actual flows and the assumed flows.

The benefits of implementing a flow based on scheduling and its related processes may generally include more accurate utilization of transmission facilities, a truer signal of congestion on specific lines, and greater utilization of the grid.

The goals of the flow-based market investigation group[38] are:

- Determine the impact of the inaccuracies associated with the use of the Rated System Path Available Transmission Capability (ATC) calculation methodology.
- Provide direction regarding what, if anything, WestConnect should do towards moving to a flow-based ATC determination.
- Investigate tools available to implement flow-based scheduling in the WestConnect footprint.
- Assess the costs and benefits of the implementation of various solutions.
- Recommend solutions if practical.

WestConnect Market Monitoring

The goal of the Market Monitoring Work Group[39] is to assess the potential for a regional market monitoring effort encompassing the WestConnect footprint. The

[37] http://www.westconnect.com/initiatives.php

[38] http://www.westconnect.com/init_flowbasedmkt.php

[39] http://www.westconnect.com/init_mktmonitor.php

work group is currently monitoring the work products of the Arizona Public Service Company's and the Public Service Company of New Mexico's single-company market monitors. Development of a regional market monitor is on hold. Work Group activities are on hold as effectiveness of the single-company monitors is assessed.

WestConnect Transmission Products

The broad goal of the Transmission Products Work Group[40] is to investigate tariff products for transmission services that serve the needs of market participants better than the traditional firm and non-firm point-to-point and network products specified by FERC.

The development and implementation of new transmission products should result in a better match of services and attractive pricing for market participants, leading to better overall utilization of the regional transmission system.

WestConnect's Total Transmission Capability/Available Transmission Capability Process

The goal of the Total Transmission Capability/ATC Process Work Group is twofold.[41]

- WestConnect's transmission owners will periodically disclose their methodology and the magnitude of total transmission capability available on each of their posted paths. The transmission owners will also provide their analysis of the impacts, if any, of their transmission expansion plans on the total transmission capability availability.
- WestConnect's transmission owners will standardize the calculation of the ATC by having OATI (an independent third party) establish a common ATC formula. Any deviations from the OATI standard will be identified on the transmission owners Open Access Same Time Information System (OASIS) page on wesTTrans, an enhanced OASIS Web site serving a significant portion of the WECC.

The benefits from disclosure of the magnitude of transfer capabilities and the standardization of the calculation of the ATC include greater awareness of the reason for transfer levels by market participants and credibility of postings on wesTTrans. The dialogue in stakeholder forums can also help identify areas where additional transfer capacity is desired.

The general schedule for work group activities consists of a stakeholder workshop held in the first quarter of each year to present the results of planning studies, and a second stakeholder workshop in the second half of each year in which the transmission owners identify planned additions to their systems.

40 http://www.westconnect.com/init_transproducts.php

41 http://www.westconnect.com/init_ttcatc.php

WestConnect Virtual Control Area

The goal of the Virtual Control Area Work Group[42] is to investigate methods and technology available for coordinating control area operations to allow participating control areas to function as a virtual control area.

In addition, the Virtual Control Area Work Group will assess the costs associated with implementing any coordinated operations as well as potential cost savings, particularly in the areas of regulation and provision of other ancillary services.

The group will develop recommendations along with supporting data for presentation to the steering committee.

Joint Initiative with the Northern Tier Transmission Group and WestConnect Overview

Representatives from the Northern Tier Transmission Group, ColumbiaGrid, and WestConnect decided to join forces in mid-2008 to pursue a number of projects of mutual interest.

WestConnect Experimental Pricing

A major issue in non-RTO and non-ISO markets is the pancaked transmission rates. A transmission customer desiring to wheel power through multiple transmission service areas has to pay multiple point-to-point transmission charges for each transmission service territory on their path.

RTOs and ISOs do away with pancaked rates by charging postage stamp tariffs (uniform rate across the RTO or ISO) or license plate tariffs (where the rate is based on the area where point of delivery is located). To work towards elimination of rate pancaking in the WestConnect footprint, eight WestConnect utilities proposed a two-year experimental transmission pricing and petitioned FERC on June 10, 2008 for guidance.

The proposed experiment offers transmission customers a single regional postage stamp transmission rate in place of multiple pancaked rates for non-firm point-to-point transmission. The single flat rate would be equal to the highest non-firm rate charged by the participating transmission owners, plus an administrative charge. The transmission customer would pay for scheduling and dispatch along with reactive and voltage control. The revenue from the transmission customer will be distributed on a pro rata basis to each participating transmission provider.

On February 12, 2009, FERC accepted the participation agreement and regional tariffs of the WestConnect pricing experiment.[43]

Currently, the nine members of the WestConnect transmission group participating in the experiment include six FERC-jurisdictional utilities, including PSCo, and three non-jurisdictional participants, including Tri-State and WAPA.

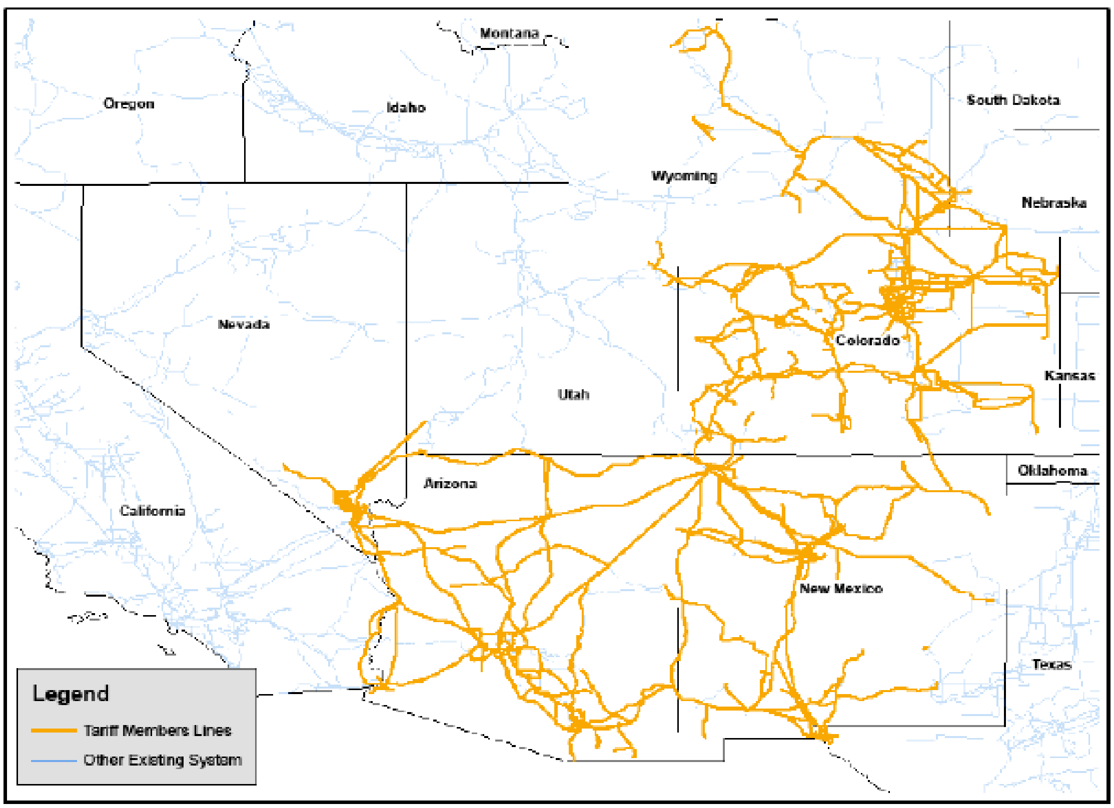
[42] http://www.westconnect.com/init_virtualcontrol.php

[43] http://uaelp.pennnet.com/display_article/353200/22/ARTCL/none/none/1/FERC-gives-final-OK-to-WestConnect-Project/

For providing these services, participants will be allocated a pro rata share of revenues based on the ratio of the ceiling rate of each transmission provider involved to the sum of those ceiling rates, provided that none of the transmission providers will collect more than their ceiling rates. All rates are those on the OASIS Web site. WestConnect participants must file minor modifications to their OATT tariffs and to the proposal before service can begin. Service under the plan is expected to begin later in the first quarter of 2009. Figure 4-3 displays the geographic reach of the pricing experiment.

This experiment is expected to result in a fuller and more efficient utilization of underutilized non-firm transmission capacity to the benefit of both the transmission customer and the participating transmission providers. The challenge is to devise a single flat pricing system for firm point-to-point transmission, while satisfying the revenue requirements of all the transmission providers.

Figure 4-3. WestConnect Experimental Tariff Transmission Facilities



Source: http://www.westconnect.com/filestorage/regional_pricing_experiment_205_filing_121208.pdf

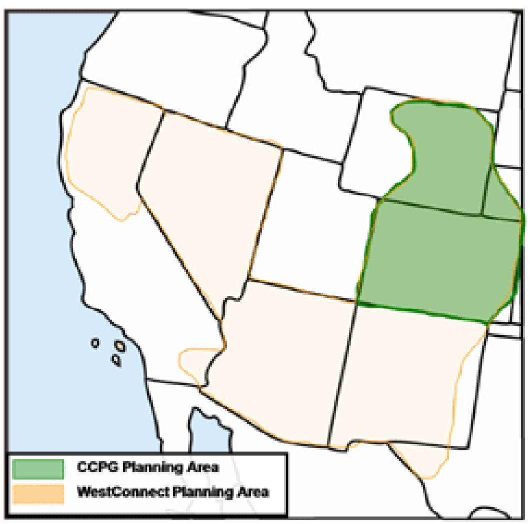
4.5 Colorado Coordinating Planning Group

The CCPG[44] was created for the purpose of providing a technical forum to conduct reliability assessments, develop joint business opportunities, and accomplish coordinated planning, under the single-system planning concept in the Rocky Mountain Region of the WECC.

The CCPG sub-regional planning group provides an open forum where any stakeholder interested in the planning of the transmission system in the CCPG footprint can participate and obtain information regarding base cases, plans, and projects and provide input or express its needs as they relate to the transmission system.

CCPG participants include PSCo, Arkansas Power River Authority, Tri-State, Colorado Springs Utilities, Colorado Association of Municipal Utilities, Platte River Power Authority, Municipal Energy Agency of Nebraska, WAPA, West Plains, Utah Associated Municipal Power Systems, Basin Electric, and the North American Power Group. Therefore, all major transmission providers in Colorado participate in CCPG. Figure 4-4 displays the CCPG footprint.

Figure 4-4. Map of Colorado Coordinated Planning Group Territory



Source: www.westconnect.com

4.6 Colorado Long-Range Transmission Planning Group

The Colorado Long-Range Transmission Planning Group[45] was initiated in January 2004 as a sub-committee of the CCPG.

44 http://ccpg.basinelectric.com/

45 http://www.rmao.com/wtpp/CO_Transmission_Planning_Group.html

The purpose of the Colorado Long-Range Transmission Planning Group is to explore jointly the potential for the development of a "backbone" transmission network in the state of Colorado that could benefit all electric load-serving entities.

Transmission planners formulate strategies to develop and improve the transmission system in the state of Colorado to support the anticipated load growth and resource requirements.

All the major transmission providers in Colorado are participants in the Colorado Long-Range Transmission Planning Group studies, including:

- Black Hills Energy.
- Colorado Springs Utilities.
- Platte River Power Authority.
- Public Service Company of Colorado.
- Tri-State.
- Western Area Power Administration.

4.7 Rocky Mountain Area Transmission Study

The Governors of Utah and Wyoming co-sponsored the Rocky Mountain Area Transmission Study[46] (RMATS) as a regional transmission planning initiative to identify the most cost-effective transmission systems given the location of potential new generation in the Rocky Mountain area. The initiatives focused on the important role new transmission would play in providing access to the region's most economical energy resources while ensuring delivery of reliable and affordable supplies of electricity to the fast growing economies of Colorado, Idaho, Montana, Utah, and Wyoming and to other parts of the Western Interconnection.

The goal of the RMATS was to identify the most critical electric transmission and generation project needs in the Rocky Mountain region, and, with broad stakeholder involvement, to provide a framework for regional collaboration to improve the Western Interconnection with technically, financially, and environmentally viable projects and to help facilitate effective developmental consideration. Public-private collaboration sponsored by the RMATS was an important aspect of regional collaboration.

A preliminary study on the integration of wind into transmission planning in the Rocky Mountain area was conducted in 2004,[47] and a final RMATS Phase I report was issued in September 2004,[48] which recommended a number of transmission projects in

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[46] http://psc.state.wy.us/htdocs/subregional/home.htm

[47] http://www.nrel.gov/docs/fy04osti/35969.pdf

[48] http://psc.state.wy.us/htdocs/subregional/FinalReport/rmatsfinalreport.htm

the region. An RMATS-sponsored conference was held in April 2006,[49] but there have been no significant new developments sponsored by RMATS since then.

4.8 The Western Governors' Association

The WGA is an association of the governors from 19 western states, and 3 US Pacific islands, and was formed to develop and communicate regional policy, serve as a leadership forum, build regional capacity, and form coalitions and partnerships to advance regional interests.

In May of 2008, the WGA and the DOE launched the Western Renewable Energy Zones (WREZ) project to discover and utilize the areas in the west with renewable energy capacity. This project was planned to address the remote locations of renewable energy projects and the cost of transmission.

4.8.1 Western Renewable Energy Zones Background

The WREZ initiative[50] includes 11 states, 2 Canadian provinces, and those areas of Mexico that are part of the Western Interconnection. Guiding the process is the Steering Committee comprising governors, Public Utilities Commissioners, Canadian premiers, and US federal officials, or their designees.

The WREZ project is generating:

1. Reliable information to support the cost-effective and environmentally sensitive development of renewable energy within each Renewable Energy Zone (REZ) and quantifying non-REZ resources.
2. Conceptual transmission plans for delivering the energy from specified zones to load centers across the Western Interconnection.

The WREZ process will not override individual state efforts to identify lands for renewable energy generation. Rather, it will provide information and tools that can be used to examine scenarios for developing renewable resources, the transmission needed to bring them to market and the associated costs.

The four phases of the WREZ Project include:

- Phase 1: Identify REZs

Identification of all the potential commercial renewable resources in the Western Interconnection will occur in Phase 1. Resources that are suitable for large-scale development and geographically proximate will be aggregated into potential REZs.

- Phase 2: Develop a Conceptual Transmission Plan to Move Power from REZs

The WREZ will work with the WECC and sub-regional transmission planning groups to develop a conceptual transmission plan that will demonstrate the delivery of energy

[49] http://psc.state.wy.us/htdocs/subregional/home.htm

[50] http://www.westgov.org/wga/press/wrez2-2-09.htm

from the identified REZs to locations where the power is needed. Modeling of transmission from the REZs and an estimation of the price of that delivered power will also be accomplished with a new, easy-to-use, computer-screening tool available to the public.

- Phase 3: Coordinate Procurement to Support Transmission Projects and a Regional Market for Renewable Energy

WGA will foster coordination of utility generation procurement schedules to help create the critical mass that would justify the construction of regional transmission to REZs.

- Phase 4: Build Interstate Cooperation to Approve and Address Cost Issues Inhibiting Large-scale Transmission Projects

The governors will engage key leaders to build cooperation and facilitate cross-state generation and transmission projects that help address siting and cost issues that have slowed the construction of large-scale transmission.

WREZ has three work groups as follows:

- The environment and lands work group is examining the development potential of REZs based on environmental, land use, and wildlife criteria. They are coordinating their efforts with the Western Governors' Wildlife Council.
- The zone identification and technical analysis work group is developing criteria to identify highly concentrated areas of energy potential for extra-high voltage transmission lines. These areas are referred to as REZs. Renewable resources that fall outside of a designated REZ will be mapped and quantified, but a full economic and environmental analysis will not be done.
- A generation and transmission modeling work group is developing a flexible and user-friendly model to evaluate the delivered price of power from a REZ to load centers and is engaging planners to study transmission needed to move that power.

4.8.2 Western Interstate Energy Board

The Western Interstate Energy Board[51] is the energy arm of the WGA. It is an organization of 12 western states and 3 western Canadian provinces. Its purpose is to provide the instruments and framework for cooperative state efforts to "enhance the economy of the West and contribute to the well-being of the region's people." The Western Interstate Energy Board seeks to achieve this through cooperative efforts among member states/provinces and with the federal government in the energy field.

Much of the work of the Western Interstate Energy Board is conducted through its three committees:

1. **The High-Level Radioactive Waste Committee**, which consists of nuclear waste transportation experts from state energy, public safety, and environmental agencies, and has been working with the DOE to develop a safe and publicly

[51] http://www.westgov.org/wieb/

acceptable system for transporting spent nuclear fuel and high-level radioactive waste under the Nuclear Waste Policy Act.

2. **The Energy and Minerals Reclamation Committee**, which consists of the state mine reclamation agencies from the western coal producing states of Colorado, Montana, New Mexico, Utah, and Wyoming, has been working to improve the administration of the Surface Mining Control and Reclamation Act in western states.
3. **The Committee on Regional Electric Power Cooperation**,[52] which consists of the PUCs, energy agencies, and facility siting agencies in the western states and Canadian provinces in the western electricity grid, has been working to improve the efficiency of the western electric power system.

The Committee on Regional Electric Power Cooperation is primarily funded through annual dues from member states and provinces, but also receives funding for special projects from non-state sources. It maintains a small technical staff in Denver.

4.8.3 Western Interconnection Regional Advisory Body

The Western Interconnection Regional Advisory Body[53] was created by the WGA under Section 215 of the Federal Power Act. This advisory body advises WECC, the ERO,[54] and FERC on whether proposed reliability standards and the governance and budgets of the ERO and WECC are in the interest of the public. FERC may request that the Western Interconnection Regional Advisory Body provide advice on other topics.

4.9 The Interwest Energy Alliance

The Interwest Energy Alliance[55] is a trade association that brings the nation's renewable energy industry together with the west's advocacy community. This mix of industry and non-governmental advocacy groups helps facilitate a consensus-based approach to project development throughout the west. Together, the members support state-level public policies that harness the west's abundant and inexhaustible renewable energy and energy efficiency resources. The primary states of focus are Arizona, Colorado, Nevada, New Mexico, Utah, and Wyoming.

[52] http://www.westgov.org/wieb/site/crepcpage/index.htm

[53] http://www.westgov.org/wirab/index.htm

[54] NERC was approved as the United States Electric Reliability Organization by FERC in 2006.

[55] http://www.interwest.org/

4.10 American Wind Energy Association

The American Wind Energy Association[56] is a national trade association representing wind power project developers, equipment suppliers, service providers, parts manufacturers, utilities, researchers, and others involved in the wind industry. In addition, the American Wind Energy Association represents hundreds of wind energy advocates from around the world.

They provide up-to-date information on:

- Operating wind energy projects.
- New projects in various stages of development.
- Companies working in the wind energy field.
- Technology development.
- Policy developments related to wind and other renewable energy development.

4.11 Open Access Same-Time Information System's wesTTrans

OASIS is an Internet-based platform that allows buying, selling, and reservation of wholesale transmission service on any electric power transmission system in the US. The origins of OASIS relate to the FERC requirements for transmission systems to provide transparent and non-discriminatory transmission service to all users of the transmission system as intended by the Energy Policy Act of 1992. The OASIS, in its current form, was formalized in 1996 through FERC Orders 888 and 889.

wesTTrans is the OASIS that is used by 26 transmission providers in the Western Interconnection, including four Colorado-based utilities (PSCo, Tri-State, WAPA, and Colorado Springs Utilities).[57] wesTTrans provides one-stop shopping for transmission users who want to reserve transmission service over multiple transmission providers in the western US. Transmission providers post available transmission capacity for anyone to purchase in accordance with the provider's FERC-approved OATT. Therefore, each transmission provider would charge its approved rate, which could be different from others. Transmission services can be sold and purchased on either a short- or long-term basis. A transmission customer wanting to wheel power across a number of different transmission systems would have to reserve and pay transmission charges for each segment of the transmission path subject to its own OATT rate, from the point of injection to the point of delivery. This is called "pancaking of rates."

[56] http://www.awea.org/about/

[57] http://www.westtrans.net/participants.html

5.1 Colorado Clean Energy Development Authority

The Colorado Clean Energy Development Authority[58] (CEDA) was created by the Colorado Legislature in 2007 (HB07-1150) to facilitate clean energy production and consumption, as well as increase transmission for clean energy.

The creation of CEDA was in concert with the bill implementing the Colorado Renewable Resource Generation Development Areas initiative (SB07-91). The objective of CEDA was to develop the renewable energy in these zones and obtain access to markets both in Colorado and outside the state. In addition, the Colorado General Assembly enacted separate legislation creating a task force to map renewable resource areas in Colorado, which culminated in the SB07-91 report.

5.2 Colorado Senate and House Bills

A series of Senate and House Bills in Colorado laid the foundation for renewable and clean energy activities in Colorado. Relevant bills and their descriptions include:

- HB06-1325: Established a transmission task force. It its November 1, 2006 report, the task force recommended to:
  - Map Colorado's renewable resource generation development areas.
  - Provide incentives for IOUs' investment in transmission.
  - Increase PUC involvement in transmission activities.
  - Encourage job training in transmission to meet the growing need,
- SB07-091: Created a 16-member task force appointed by the governor and legislative leadership to map Colorado's renewable resource generation development areas.
- SB07-100: Required identification of REZs, provided incentives (construction work in progress) for IOUs to develop transmission to such zones, schedules, and required applications for certificates to build transmission. SB07-100 applied only to IOUs.
- HB07-1037: Directed the CPUC to establish energy saving goals and provided financial incentives for IOU energy efficiency programs.
- HB07-1150: Created the CEDA.

[58] http://www.colorado.gov/energy/index.php?/utilities/category/clean-energy-development-authority/

- HB07-1169: "Net Metering," this bill ensured compliance with interconnection standards and insurance requirements.
- HB07-1203: "Energy Management Conservation Studies." This bill directed the Colorado Governor's Energy Office to fund two projects. In one project, Colorado State University was to assess the potential for carbon sequestration and greenhouse gas mitigation for each county. In the other, the University of Colorado was to conduct an energy profile to provide data and analysis regarding Colorado's current and projected energy resources.
- HB07-1279: This bill provided tax credits for purchasing wind generating equipment and tax refunds for research and development equipment.
- HB07-1281: Doubled the renewable standard portfolio set in Amendment 37 and required REAs and Munis to participate (20 percent renewable energy for IOUs by 2020, 10 percent renewable energy for Munis and REAs by 2020).
- HB07-1288: "Recycling." Part of this bill required the assessment of opportunities to generate renewable energy from discarded waste. One of the justifications of the bill was that recycling saves energy.
- HB08-1160 and HB08-1164: Dubbed the "go solar" legislative package, HB08-1160 extended net-metering to include Co-ops and Munis, and HB08-1164 strongly encouraged the bigger utility companies to begin acquiring large-scale (2 MWs or more) solar power plants to help meet the state's future energy needs.
- HB09-1149: This bill offered homebuilders the option to pre-wire their houses for solar system installations.
- HB09-1312: Just passed in March of 2009, and touted as the "Renewables for Schools" loan program, this bill makes low interest loans available in the amount of $10,000 and up for schools that want to offset future energy costs by investing in renewable energy systems now.
- SB09-51: "Renewable Energy Finance Act," takes numerous steps to make solar energy systems more affordable for homeowners and improve market conditions for solar energy companies doing business in Colorado. The bill creates financing models that can help homes and businesses spread out the up-front costs of a system over several years, similar to purchasing and financing a car. The bill also provides treasury bonds to participating banks and lenders that will provide more financing options for solar installation.

5.2.1 Colorado Clean Energy Development Authority Legislation

According to the HB07-1150, CEDA was nominally intended to have the powers sufficient to enable it to:

- Facilitate the production and consumption of clean energy.
- Increase the transmission and use of clean energy by financing and refinancing projects located within or outside the state for the production, transportation,

transmission, and storage of clean energy, including pipelines, and related supporting infrastructure and interests therein.

However, the CEDA statute contains an infirmity that prohibits the CEDA from entering into commercial lending. Absent that ability, CEDA cannot function. A latest effort in introducing legislation in the Colorado Assembly to extend powers and authorities of CEDA, were put aside due to lack of legislative consensus. Therefore, as of the spring of 2009, CEDA is playing a very limited role in shaping the development of renewable energy development infrastructure in Colorado.

5.3 Colorado Clean Energy Development Authority's Future

CEDA will continue to pursue legislation that will amend the self-cancelling language in HB07-1150. Once remedied, the CEDA will have the power to:

- Hire employees as necessary.
- Maintain records and accounts as required by the state auditor.
- Convene task forces to develop proposed recommendations regarding the types of clean energy projects that the CEDA should finance.
- Finance projects and enter into financing agreements.
- Issue bonds and refunding bonds.
- Enter into contracts and financing agreements, as necessary.
- Use monies in the Colorado Clean Energy Development Authority Fund to fund loans or enter into other financing agreements.
- Use any portion of the fund to secure the payment of bonds or other obligations.
- Receive and accept gifts, grants, and donations.
- Enter into contracts or agreements, as necessary.
- Sell, with or without public bidding, notes, bonds, loans, or any other secured or unsecured obligations.

5.4 Examples of Other Transmission Authorities

A number of state transmission infrastructure authorities, such as CEDA in Colorado, have been created by state authorities to help facilitate or finance development of new transmission facilities to access mostly renewable energy resources in their states. In most instances these authorities are empowered to issue bonds in support of transmission and generation developments.

A recent study reviewed the status of a number of state transmission authorities in the US.[59] This section provides a summary of those findings. The seven state authorities reviewed are shown in Figure 5-1 and include the following, ordered by year of inception:

- Wyoming Infrastructure Authority, 2004.
- Idaho Energy Resources Authority, 2005.
- Kansas Electric Transmission Authority, 2005.
- North Dakota Transmission Authority, 2005.
- South Dakota Energy Infrastructure Authority, 2005.
- CEDA, 2007.
- New Mexico Renewable Energy Transmission Authority, 2007.

[59] Porter, K. and Fink, S, Exeter Associates, Inc. "State Transmission Infrastructure Authorities: The Story So Far, December 2007 – December 2008," Columbia, Maryland, Subcontract Report, REL/SR-500-43146, May 2008. And,

Porter, K. and Fink, S, "State Transmission Infrastructure Authorities: The Story So Far," The Electricity Journal, March 2009, Vol.22, Issue 2.

Figure 5-1. Transmission Authorities in Other States

Source: Porter, K. and Fink, S, Exeter Associates, Inc. "State Transmission Infrastructure Authorities: The Story So Far, December 2007 – December 2008," Columbia, Maryland, Subcontract Report, REL/SR-500-43146, May 2008.

5.4.1 General Features of State Infrastructure Authorities

The powers and responsibilities of state infrastructure authorities vary by state. The general features of state infrastructure authorities include:

- Some authorities can pursue generation and distribution projects in addition to transmission projects.
- Some authorities have the authority to exercise the power of eminent domain with respect to project siting in their jurisdictions.
- The authorities are not agents of the state, and therefore, the issued bonds, if any, are not liabilities of the state, but rather, the authorities themselves.

- Most of the authorities can issue revenue bonds, secured by a revenue stream from the transmission investment, therefore, they will not rely on the full faith and credit of the state.
- The bonds are exempt from state taxes, but are subject to federal taxes.
- All the authorities are expected to be financially self-supporting in the long run, with revenues based on the returns from the completed projects.
- Project types, bond issuing processes, and ownership and operational authorities for the projects vary by state.

5.4.2 Wyoming Infrastructure Agency

The Wyoming Infrastructure Authority[60] (WIA), created in June 2004 by the state legislator, is a state organization with funding authority having goals that include improving the state's electric transmission system, facilitating the increased utilization of Wyoming's coal and wind resources, and coordinating with other states in the western system power grid to address transmission constraints.

WIA is responsible for facilitating the development of the electric transmission infrastructure through planning, financing, building, maintaining, and operating interstate electric transmission and related facilities.

WIA's role was expanded in the 2006 session of the legislature to become directly involved in financing and promoting advanced coal technologies related to electric generation.

Specific tools and responsibilities of the WIA include:

- Issuing revenue bonds to finance new transmission lines and advanced coal plants.
- Extending up to $1 billion in bond financing for projects owned by private parties.
- Entering into partnerships with public or private entities to build and upgrade transmission lines and develop advanced coal plants.
- Owning and operating transmission lines in instances where private investment is not offered.
- Investigating, planning, prioritizing, and establishing corridors for electric transmission.
- Establishing and charging fees and rates for use of its facilities.
- The WIA has the power of condemnation in Wyoming, and is not subject to Wyoming Public Service Corporation jurisdiction. WIA has bonding capability, and it can partner with the private sector. It has a cap of $1 billion for projects not owned by the WIA, but has no cap for projects owned by WIA. It can sponsor projects, providing financial backing to other projects, including turnkey projects. It can be an owner and operator of facilities.

[60] http://www.wyia.info/

- The WIA focuses on promoting Wyoming energy development opportunities and creating partnerships with other entities. This has brought two private transmission companies into Wyoming that had not previously been active in the state. The WIA and Trans-Elect Development, along with the WAPA, are developing the Wyoming Colorado Intertie Transmission Project.
- The WIA has also formed a partnership with National Grid and, along with WAPA, are assessing the feasibility of the Wyoming West Project, a 345-kV or 500-kV line running from Wyoming through Utah and Nevada and possibly into California.
- The WIA/National Grid partnership, along with Arizona Public Service, is also heading up a consortium that wants to develop the TransWest Express, a transmission line from Wyoming extending into the southwest. This project is currently in the design and permitting phase.
- In August 2007, WIA, National Grid, and the Arizona Public Service Company entered into an agreement with PacifiCorp to cooperate on initial activities to co-develop the Gateway South and TransWest Express transmission projects. Gateway South is a proposed transmission line from PacifiCorp that would begin in Wyoming and extend into Utah and the desert southwest.
- The WIA also has a role in promoting advanced coal technologies; and to that end, WIA has teamed with PacifiCorp to conduct feasibility studies on four potential alternative integrated gasification combined-cycle technologies for possible future pilot project development.
- The WIA recently had its first successful bonding issuance with $34.5 million in bonds to help finance a transmission line being constructed by Basin Electric Power Cooperative of Bismarck.

5.4.3 Idaho Energy Resources Authority

The Idaho Energy Resources Authority[61] was established in 2005 with the support of the Idaho Consumer-Owned Utilities Association, representing 22 electric cooperatives and municipalities. It was created to promote development and financing of electric generation and transmission facilities for the benefit of Idaho electric utilities and renewable energy project developers. The Idaho Energy Resources Authority is governed by a seven member board appointed by the governor. They do not have a statutory cap on the amount of bonds it can issue. The Idaho Energy Resources Authority was working with the Bonneville Power Administration to assume a major role as a conduit financier in Bonneville Power Administration’s third party financing program for transmission facilities throughout Idaho and the northwest. They do not receive any appropriations from the state, but rather anticipates long-term funding of its operation with fees from bond issuances.

[61] http://www.iera.info/announcements.html

5.4.4 Kansas Electric Transmission Authority

The Kansas Electric Transmission Authority[62] was created to develop more transmission for facilitating the growth of Kansas-based generation. They are governed by a seven-member board of directors. The Kansas Electric Transmission Authority contracts with the Kansas Development Finance Authority for revenue bonds to finance projects and therefore does not have a maximum bond limit. Unlike most of the other state transmission infrastructure authorities, the Kansas Electric Transmission Authority can only be involved with transmission projects and the legislation only allows for transmission development and ownership; operations must be contracted out. They can become involved with projects outside of Kansas but only if the state realizes at least 51 percent of the economic benefit.

5.4.5 North Dakota Transmission Authority (NDTA)

North Dakota Transmission Authority[63] (NDTA) is intended to diversify and expand the North Dakota economy by facilitating development of transmission in support of the production, transportation, and consumption of electricity sourced in North Dakota. NDTA is part of the North Dakota Industrial Commission and can (among other things):

- Offer grants or loans and provide other forms of financial assistance.
- Execute contracts.
- Borrow money and issue bonds.
- Accept aid, grants, or contributions.
- Plan, finance, develop, acquire, own in whole or in part, lease, rent, and sell or divest electric transmission facilities.
- Enter into contracts to construct, maintain, and operate electric transmission facilities.
- Investigate, plan, prioritize, and propose corridors for electricity transmission.
- Confer with the North Dakota Public Service Commission, other state or federal authorities, and/or regional transmission organizations.
- Work to establish rates, fees, or tariffs for transmission facilities and services offered by the NDTA, in consultation with, and subject to, the approval by the North Dakota Public Service Commission.

Any transmission facilities financed and/or constructed by the NDTA are exempt from property taxes for up to five years. After 5 years, transmission facilities over 230 kV are still exempt from property taxes but are taxed at a per-mile rate.

[62] http://www.kansas.gov/keta/

[63] http://www.legis.nd.gov/assembly/60-2007/docs/pdf/edt092308appendixc.pdf

5.4.6 South Dakota Energy Infrastructure Authority

The South Dakota Energy Infrastructure Authority[64] (SDEIA) was created to facilitate the development of energy production facilities and energy transmission facilities both inside and outside of South Dakota. SDEIA is a separate stand-alone entity that may (among others things):

- Make and execute contracts, borrow money, and issue bonds.
- Employ engineers, attorneys, and other consultants and employees.
- Contract with agencies of the state to provide staff and support services.
- Make loans and grants, and enter into financing agreements with any governmental agency or any person for the costs incurred in connection with the development, construction, acquisition, improvement, maintenance, and operation of decommissioning of electric transmission facilities.

The SDEIA may finance, construct, develop, maintain, operate, and decommission new or upgraded transmission facilities. However, SDEIA is not designed to own and/or operate transmission facilities, but to facilitate the development of transmission infrastructure by other parties. SDEIA can establish fees, rates, tariffs, or other charges for the use of its facilities and for all services it renders, but must consult with the PUC and any other relevant governmental authority prior to doing so. The SDEIA also has the authority to investigate, plan, prioritize, and establish transmission corridors and may enter into partnerships with public or private entities to develop and operate transmission facilities. SDEIA may lease, rent or own transmission facilities, although it must divest ownership of any transmission facility as soon as economically practicable, defined as recovery of SDEIA's net investment.

SDEIA is also required by statute to help entities that wish to develop new, or upgrade existing, transmission lines through designing a business plan and identifying potential financing options. SDEIA must also help other state transmission infrastructure authorities and federal or regional entities that wish to develop new, or upgrade existing, transmission.

5.4.7 New Mexico Renewable Energy Transmission Authority

The New Mexico Renewable Energy Transmission Authority[65] (RETA) was created to develop transmission facilities and storage projects. Any transmission project that RETA undertakes must source at least 30 percent of the energy from renewable resources. RETA is governed by an eight-member board. RETA received initial funding of $1 million through July 2008. RETA is also authorized to issue revenue bonds and has no financing cap.

[64] http://www.sdeia.com/

[65] http://www.nmreta.org/

RETA's activities will help support the New Mexico RPS, but load growth in the state is low and therefore RETA is also focused on exporting renewable energy in New Mexico to surrounding states with RPS requirements, especially Arizona and California.

RETA has joined a consortium with WIA, CEDA, and seven utilities, which are considering developing the High Plains Express Transmission Project. RETA, unlike some other authorities, can own and operate facilities, but prefers to take on the role of facilitator, identifying projects and then turning them over to the private sector to construct and operate.

5.4.8 Comparison of State Transmission Authorities

Table 5-1 provides a summary comparison of the responsibilities and powers of the state transmission authorities. This table demonstrates that CEDA has very limited authority.

Table 5-1. Comparison of State Transmission Authorities

Characteristics:
The state infrastructure authorities have various different requirements and capabilities based on the design characteristics incorporated into their respective legislation.

	Issues Revenue Bonds	Cap on Bonding Amount	Can Own Facilities	Can Operate Facilities	Required to Divest Facilities	Required to Give Public Notice	Power of Eminent Domain within Their States
Colorado (CEDA)							
Idaho (IERA)	√		√	√	√[6]		√
Kansas (KETA)	√[1]		√			√	√
New Mexico (RETA)	√		√[3]			√	√
North Dakota (NDTA)	√	√	√	√		√	
South Dakota (SDEIA)	√	√	√	√	√		√
Wyoming (WIA)	√	√[2]	√[4]	√[5]	√	√	√

1 Contracts with Kansas Development Finance Authority for the bonds.
2 Cap only applies to bond issuances for private sector projects, not for WIA's own projects.
3 Must be leased to another entity.
4 Policy preference is not to own and operate facilities.
5 Policy preference is not to own and operate facilities.
6 IERA must partner with a utility or IPP and then can request that IERA divest a facility.

Source: Porter, K., and Fink, S., NREL/PO-500-43086, WINDPOWER 2008, Houston, TX, June 1–4, 2008 (with slight modification by R. W. Beck of the information on CEDA and numbering of the notes)

5.4.9 Lessons from Other State Authorities

All the existing state infrastructure authorities are relatively young, with the WIA being the one with most experience. Therefore, it is too early to draw any specific conclusion based on the available historical evidence. However, Porter and Fink, in their report for NREL,[66] provide a general set of common sense recommendations based on their observations for any state that may wish to create a transmission infrastructure authority. These include:

- Organizational Funding: Adequate funding for a sustainable organization to enable staffing, investing in early-stage feasibility studies, and to build support for large-scale transmission projects.
- Authority to Issue Bonds: For the state infrastructure authority to have any actionable power, it is of the utmost importance to have authority to issue bonds for financing of projects. Otherwise, the authorities would become nothing more than a state advocacy group without actual power to help develop transmission.
- Independence: Allow independence in terms of decision making, planning, and financing with legislative oversight, but without the need for legislative approval of each and every decision and action by the state infrastructure authority.
- Starting with Small Steps: Start with smaller projects to allow learning on the job, particularly in terms of planning, selecting projects, issuing bonds, and getting various market entities to participate.
- Financial Partnership with Other Entities: Financial partnership with other entities fosters support by market participants, in addition to hedging the risks associated with larger-scale projects.
- Allow Ownership of Transmission Facilities: Allowing state infrastructure authorities to own projects that they help develop, would energize the traditional transmission developers into action in view of the competition that the state infrastructure authority would provide.
- Stakeholder Involvement: Public meetings and outreach and partnerships with other entities help facilitate regional transmission planning and helps leverage additional resources.

To help CEDA evolve into a vigorous and effective state infrastructure authority, the most essential requirement is its empowerment to issue tax exempt bonds and directly engage in planning, financing, development, ownership, and operation of transmission infrastructure in Colorado that may not be of primary of timely interest to utility transmission developers. Most or all of the recommendations listed above provide a reasonable roadmap for legislative action on CEDA.

[66] Porter, K., and Fink, S., "State Transmission Infrastructure Authorities: The Story So Far, May 2008.

6.1 Regulation of Transmission

The business of electricity transmission in the US comes in different shapes and forms. FERC has jurisdiction over the interstate transmission of electricity. Typically, state utility commissions have jurisdiction over the regulation of public utilities in their states, local governing boards regulate Munis, and member boards regulate the REAs.

In general, the transmission business in the US, with the exception of a few merchant transmission companies, is a franchised monopoly, and therefore, a cost-of-service-based regulated service.

6.1.1 Federal Regulation

A number of federal bodies have authority over the interconnected transmission system and the generation and transmission entities that are formed or empowered at the national level. These bodies include, but are not limited to, the following the:

- FERC: Responsible for utility corporate policy, wholesale electricity markets, and interstate transmission rates.
- NERC: Responsible for transmission grid reliability.
- Department of Energy/Energy Information Agency: Responsible for national energy policy, national interest electric transmission corridors, and data collection and analysis.
- Department of Agriculture/Forest Service, and the Department of Interior/ Bureau of Land Management: Responsible for rights-of-way and land use management in federal land, and financing and oversight of federal power marketing administrations.
- Federal Utilities: Ownership and operation of federal hydroelectric facilities.
- Environmental Protection Agency: Responsible for environmental regulation.

The reason regulation of interstate transmission falls under the jurisdiction of the FERC is because of the role transmission plays in interstate trade in the US, and all regulation of all interstate trade is under federal jurisdiction by US law.

6.1.2 State Regulation

At a regional and local level, states play an important role in regulating businesses of natural monopolies for the interest of the citizens. The basic authority and state jurisdiction is typically established by the legislators in each state. Most state PUCs are empowered to regulate public utilities in their states, which are mostly franchised natural monopolies. The exceptions are municipal and cooperative utilities and federal power marketing administrations. State PUCs usually review and set the retail rates for the public utilities and have primary responsibility for approval and siting of transmission projects and upgrades. Environmental issues, land use, and eminent domain fall under state authority. However, in most cases, local authorities have significant control over siting and permitting of new transmission development.

State regulatory commissions determine whether a project is needed, how and when it should be built, and when transmission owners can pass their costs to customers in electric rates. State regulators and siting authorities are authorized to make those decisions on behalf of consumers. Where federal jurisdiction is clear, states generally are obliged to pass on to retail customers federal jurisdictional costs that are found to be prudently incurred by federal regulators.

All transmission costs, both capital and ongoing, are considered for recovery by state PUCs in retail rate proceedings. Prudent transmission costs are recovered from customers in the price they pay for bundled electric service.

Utilities collect revenues from firm and non-firm wholesale transmission customers through contracts or through their OATT, which are then credited to retail customers, just as wholesale wheeling purchases of transmission service from other utilities through contracts or the OATTs are included as expenses in retail rate proceedings.

6.1.3 National Legislation Impacting Transmission

The following sections provide an overview of various national legislation and federal rules impacting electricity transmission in the US.

Public Utility Holding Company Act

The first major federal regulation of the electric power industry was the 1935 Public Utility Holding Company Act, in response to the creation of a handful of major national electricity utility monopolies. This act limited the geographical scope of utility holding companies and the corporate structure of the holding companies, and allowed for the creation of vertically integrated utilities in monopolized service areas.

The Federal Power Act

The first appearance of the Federal Power Act was actually in the form of the Federal Water Power Act in 1920, created to coordinate hydroelectric projects in the US. The Federal Power Commission was created by this act as the licensing authority for these plants. In 1935, the law was renamed the Federal Power Act and the Federal Power Commission's regulatory jurisdiction was expanded to cover all interstate transmission of electricity. This commission was the precursor to today's FERC.

Two other major pieces of federal legislation in recent years are the 1978 Public Utility Regulatory Policies Act and the 1992 Energy Policy Act.

Public Utility Regulatory Policies Act

The Public Utility Regulatory Policies Act of 1978 introduced some modicum of competition by requiring that utilities buy power at an "avoided cost" rate from other companies not owned by or associated with the utility itself. Consequently, this act created a new industry of independent power producers. The Act also required that the non-utility generators be given access to the transmission system in order to deliver their power onto the grid.

Energy Policy Act

The Energy Policy Act was passed by Congress in 1992. The Energy Policy Act required that the independent power producers, or any utility, be given access to the utilities' transmission grid on rates and terms that were comparable to those that the utility would charge itself for access to the grid. The access to the transmission grid was the impetus behind the growth of wholesale power markets. Since the mid-1990s, the FERC has issued several orders to carry out the goals of the Energy Policy Act.

Energy Policy Act of 2005

On July 29, 2005, the Congress passed the EPAct 2005, and it was signed by the President on August 8, 2005. This legislation addressed, among other things, energy efficiency, renewable energy, nuclear energy, and electricity-related reforms. It also provides incentives for oil and gas production and encourages the deployment of clean coal technology. Many of FERC's rulemakings implementing the EPAct 2005 are discussed in the preceding section of this report.

The EPAct 2005 did not include a federal requirement that utilities purchase a certain percentage of electricity from renewable sources, or a national RPS. Although federal legislation requiring a national RPS may be enacted in the future, renewable resource requirements are currently based on state-by-state considerations, which may include adoption of a statewide RPS.

EPAct 2005 included a requirement under the Public Utility Regulatory Policies Act for utilities (both regulated, through the appropriate regulatory authority and non-regulated utilities) to consider the adoption of standards pertaining to:

- The implementation of net metering service.
- Ensuring fuel diversity in generating resources.
- Increased efficiency of fossil-fueled generating resources.
- The installation of time-based metering and communications.
- Interconnection of distributed generation.

Utilities that sell power only at the wholesale level and do not sell power at the retail level are exempt from the Public Utility Regulatory Policies Act of 1978 requirements. In Colorado, this means that Tri-State is exempt.

EPAct 2005 authorized the DOE to designate appropriate areas where transmission congestion exists or could exist as national corridors. Under certain conditions, FERC would have authority to approve siting and construction of transmission projects within corridors, if the:

- State has limited or no authority over the project.
- Project does not serve retail customers in the state.
- Approval of a project has been withheld for over a year.

To date, the FERC has not exercised this authority.

The National Environmental Policy Act

The NEPA of 1969, which came into effect on January 1, 1970, requires that all federal agencies systematically consider and document environmental impacts of their proposed actions on human and natural environments. The intent is to promote better planning and decision-making by making available high quality information to officials and the public, before undertaking any major federal action.

Any federal action that may have a significant impact on the environment requires preparation of either a comprehensive Environmental Impact Statement or a less detailed Environmental Assessment.

An Environmental Impact Statement should provide detailed analysis of impacts of the proposed action, discussion of ways to avoid, mitigate, or reduce the adverse impacts, and comparisons with a range of potential alternatives, including the case when no action will be taken.

The NEPA process requires that hearings be held and a comment period provided to solicit comments from the public and other interested parties, and follow-up consultations be held with appropriate federal, state, local, and tribal governmental agencies.

As a public agency, actions of WAPA fall under the jurisdiction of NEPA. In addition, the Rural Utilities Service requires preparation of an Environmental Assessment under NEPA by Tri-State when Tri-State uses Rural Utilities Service's funds to undertake major projects.

6.1.4 Federal Energy Regulatory Commission Orders

FERC Rulemakings

The Energy Policy Act of 1992 and the FERC's subsequent rulemaking activities were undertaken to foster increased wholesale competition in the electric power sector. FERC's 1996 Orders No. 888 and No. 889 established a standard pro forma OATT, requiring most IOUs to file OATTs with the FERC. To satisfy FERC's "reciprocity" requirements described later, some non-jurisdictional transmission providers also filed OATTs, mostly in the form of FERC's pro forma OATT, enabling such non-jurisdictional utilities to obtain from, and offer transmission service to, jurisdictional public utilities.

The rulemakings issued in 1999 and 2000 (FERC Order No. 2000 and Order No. 2000A) were issued to advance the formation of RTOs across the country. The establishment of RTOs was intended to address remaining transmission related impediments to a competitive wholesale electricity market. FERC Order No. 2000 and No. 2000A encouraged the formation of RTOs as a way to handle the challenges associated with the movement of electricity and operation of multiple interconnected independent power supply companies over large interstate areas. RTOs are tasked with providing non-discriminatory transmission access, facilitating competition among wholesale suppliers to improve transmission service, and providing access to structured energy markets. Although early efforts considered the formation of an RTO in Colorado, utilities within Colorado are not participants in a RTO.

FERC has also issued rulemakings required to implement portions of the EPAct 2005 and other FERC initiatives. Such efforts to date have included, but are not limited to:

- The certification of NERC as an ERO and the establishment of mandatory reliability standards.
- Transmission pricing reforms.
- The designation by the DOE of transmission corridors with acute transmission constraints or congestion problems that enables FERC to issue permits to construct transmission facilities within these corridors under certain circumstances.
- Reforms to the Order No. 888 pro forma OATT.
- Native load service obligations.
- Guidelines for a framework addressing the provision of long-term firm transmission rights in RTO regions.

Certain of these rulemakings are summarized in the sections below.

FERC Order 888

FERC Order 888 detailed how transmission owners should charge for use of their lines and the terms under which they should give others access to their lines. Order 888 also required utilities to functionally unbundle, i.e., to separate, their transmission and generation businesses and to follow a corporate code of conduct. FERC hoped that this separation would prevent the transmission business from giving the utility's generation resources preferential access to the utility's transmission lines.

Order 888's primary objective was to establish and promote competition in the generation market, by ensuring fair access and market treatment of transmission customers. FERC outlined six points to accomplish this goal:

- Require all jurisdictional utilities (within the United States) to file an OATT.
- Require IOUs to functionally unbundle wholesale generation and power marketing from transmission services.
- Create ISOs and operating guidelines.
- Encourage reciprocity for non-jurisdictional utilities.
- Allow utilities to recover stranded costs.

- Identify ancillary and comparable services to properly operate the bulk power system.

One immediate result of this order was the functional separation of power marketers and schedulers from their company's transmission operations and closing of any channels for making "insider information" on transmission system operations and scheduling available to them. Utilities were obliged to treat their affiliated power marketers just as they would external parties.

FERC Order 889

FERC Order 889 created an on-line system through which transmission owners could post the available capacity on their lines and make such information publicly available for other potential users of the transmission system.

Order 889 went to great lengths to define in detail exactly how all participants in the electricity market should interact with transmission providers. It laid out the structure and function of what would become known as OASIS "nodes," which are secure, Web-based interfaces to each transmission system's market offerings and transmission availability announcements. Each OASIS node was to be the single point of information dissemination to the market as well as the customer portal for transmission service requests, even for affiliated power marketers wanting access to their own parent company's transmission.

FERC Order 2000

FERC Order 2000 encouraged transmission-owning utilities to form RTOs. FERC did not require utilities to join RTOs; instead, it asked that the RTOs meet minimum conditions, such as an independent board of directors. FERC gave these regional organizations the task of developing regional transmission plans and pricing structures that would promote competition in wholesale power markets, using the transmission system as a highway for that wholesale commerce.

FERC Order 890 (OATT Reforms)

In February 2007, FERC amended its regulations and the pro forma open access transmission tariff (pro forma OATT), adopted in Order Nos. 888 and 889, to remedy opportunities for undue discrimination and address deficiencies in the pro forma OATT that had become apparent since the issuance of those orders.[67]

All public utilities, including RTOs and ISOs, were required to file revisions to their OATT to conform to Order No. 890. Order No. 890 became effective on May 14, 2007. On December 20, 2007, FERC issued Order No. 890-A, which was an order on rehearing and clarification of Order No. 890. Order No. 890-A substantially reaffirmed Order No. 890 with only minor changes. During 2008, FERC issued during 2008 two additional orders (890-B and 890-C) providing further clarification of its original reform Order No. 890.

[67] http://www.ferc.gov/industries/electric/indus-act/oatt-reform/order-890/fact-sheet.pdf

Order 890 requires transmission providers to detail how their local, sub-regional, and regional transmission planning processes will meet the Order's 9 requirements, which focus on stakeholder involvement, transparency, regional coordination, economic planning, and cost allocation.

To accomplish its objectives with respect to transmission planning, FERC required the development of regional planning processes that limit the opportunities for undue discrimination and ensure that comparable transmission service is provided by all public utility transmission providers. As further discussed below, FERC required that each public utility transmission provider submit, as part of a compliance filing, a proposal for a coordinated and regional planning process that complies with nine planning principles: coordination, openness, transparency, information exchange, comparability, dispute resolution, regional participation, congestion studies, and cost allocation.

While FERC directed all transmission providers to develop regional planning processes, it explained that transmission-owning members of ISOs or RTOs must participate in the ISO or RTO regional planning processes for their local planning issues, since planning on the regional level would be addressed by the ISO or RTO processes.

According to FERC's Order No. 890 Fact Sheet,[68] the purposes of the final rule for "Preventing Undue Discrimination and Preference in Transmission Service" are to:

- Strengthen the pro forma OATT to ensure that it achieves its original purpose of remedying undue discrimination.
- Provide greater specificity in the pro forma OATT to reduce opportunities for the exercise of undue discrimination, make undue discrimination easier to detect, and facilitate the Commission's enforcement.
- Increase transparency in the rules applicable to planning and use of the transmission system.

Core elements of Order No. 888 that were retained:

- Comparability requirement.
- Protection of native load.
- States' jurisdiction over bundled retail load.
- Functional unbundling to address undue discrimination.
- Reciprocity.

The major reforms:

- Greater consistency and transparency in the ATC calculation.
- Open, coordinated, and transparent planning on both a local and regional level.
- Reform of energy and generator imbalance penalties.

[68] http://www.ferc.gov/industries/electric/indus-act/oatt-reform/order-890/fact-sheet.pdf

- Adoption of a "conditional firm" component to long-term point-to-point service and reform of existing requirements for the provision of re-dispatch service.
- Reform of rollover rights policy.
- Clarify tariff ambiguities.
- Increase transparency and customer access to information.

The final rule's applicability:

- The rule applies to all public utility transmission providers, including RTOs and ISOs. Each such public utility will be required to file the revisions to the pro forma OATT following the issuance of the final rule.
- As with Order No. 888, a public utility may demonstrate that its existing terms and conditions of open access transmission service are consistent with, or superior to, the pro forma OATT.
- The purpose of the rule is not to redesign approved, fully-functional RTO or ISO markets. The Commission does not expect that substantial changes to those markets would be required as a result of this final rule.

6.1.5 Reforms from FERC Order No. 890 Fact Sheet

Available Transmission Capability

ATC is the transfer capability remaining on a transmission provider's transmission system that is available for further commercial activity over and above already committed uses. Transmission providers currently calculate the ATC for their systems using different assumptions and methodologies.

After concluding that the absence of a consistent ATC methodology increases the discretion of transmission providers and the opportunities for undue discrimination in the application of the *pro forma* OATT, in the final rule the Commission requires:

- Consistency in all ATC calculation components and some data inputs and modeling assumptions, as well as consistency in the exchange of data between transmission providers.
- Public utilities, working through the NERC and the North American Energy Standards Board, to develop appropriate standards within 9 and 12 months of the final rule, respectively.
- Increased transparency of ATC calculations through the inclusion in each transmission provider's OATT of its specific ATC calculation methodology, and through posting of relevant data and models on each transmission provider's OASIS.
- Transmission providers to post on OASIS metrics relating to transmission requests that are approved and rejected.

Coordinated Transmission Planning

The Commission concluded that transmission providers have a disincentive to remedy increasing transmission congestion on a nondiscriminatory basis and that the current pro forma OATT does not adequately address this problem. Therefore, the final rule requires that:

- Transmission providers participate in a coordinated, open and transparent planning process on both a local and regional level.
- Each transmission provider's planning process meet the Commission's nine planning principles, which are coordination, openness, transparency, information exchange, comparability, dispute resolution, regional coordination, economic planning studies, and cost allocation.
- Each transmission provider must describe its planning process in its tariff.
- The Commission will allow regional differences in planning processes.

Pricing of Imbalances

Differences between the scheduled and the actual delivery of energy to a load (energy imbalances) and differences between the energy scheduled for delivery from a generator and the amount of energy actually generated in an hour (generator imbalances) are both corrected by transmission providers to keep the system in balance. Existing policies for pricing energy and generator imbalances provide wide discretion in the development of these charges and allow the potential for undue discrimination. The Commission finds that existing energy and generator imbalance charges are excessive, too varied, and otherwise unrelated to the cost of providing the service, and therefore, reforms energy and generator imbalance pricing as follows:

- The Commission revises the existing pro forma OATT Schedule 4 for energy imbalances and adopts a new Schedule 9 for generator imbalances to require imbalances to be based on a tiered structure similar to the imbalance provision used by the Bonneville Power Administration. In these new provisions, imbalance charges escalate as the imbalance increases and are based on incremental cost. Intermittent resources are exempt from the highest deviation band.
- Any deviation from these provisions must be consistent with or superior to the pro forma OATT as modified by this final rule and must meet the following criteria. The charges must
    - Be related to the cost of correcting the imbalance.
    - Be tailored to encourage accurate scheduling behavior, such as by increasing the percentage of the adder as the deviations become larger.
    - Account for the special circumstances presented by intermittent generators.

Requests for Firm Point-To-Point Service

The Commission concludes that the existing methods for evaluating requests for long-term, firm point-to-point transmission service are no longer just, reasonable and not unduly discriminatory. This is so because a transmission customer may be denied service when its transaction is not deliverable during as little as one hour of the service period, while transmission providers need not eliminate otherwise economic options under similar conditions. To remedy this problem, the Commission modified the pro forma OATT, as follows:

- The Commission adopts a "conditional firm" component to long-term, firm point-to-point service that requires the transmission provider to identify either defined system conditions or an annual number of hours during which service will be conditional, and allows the customer to select one of them.
- Transmission providers also have an obligation to evaluate the provision of re-dispatch from their own resources and provide customers with information on the capabilities of other generators to provide re-dispatch.
- The duration of both service options is limited to a time period over which service can be reasonably provided without impairing reliability.
- After the end of each month, transmission providers must post certain information associated with the actual cost of re-dispatch services provided that month.

Rollover Rights

The Commission revised the rollover provision in the pro forma OATT, which grants an ongoing right to transmission customers to renew or "rollover" their contracts, to apply to contracts that have a minimum term of five years, rather than the current minimum term of one year. A customer must provide notice of whether or not it will exercise its right of first refusal to renew the contract no less than one year prior to the expiration date of the transmission service agreement, rather than within the current 60-day period. These reforms promote consistency between the rights of rollover customers and the resulting obligations of transmission providers to plan and upgrade the system to accommodate rollovers.

Examples of Increases in Transparency

- In addition to the increased transparency included in the ATC and planning reforms described above, the Commission requires transmission providers to post on OASIS all business rules, practices, and standards that relate to transmission services provided under their OATTs, and to include their credit review procedures in their OATTs.
- The Commission requires transmission providers and their network customers to use the transmission provider's OASIS to request designation of a new network resource and to terminate the designation of an existing network resource.

Pro Forma OATT Reform

- The final rule includes a number of posting and reporting requirements that will provide the Commission and market participants with information about each transmission provider's performance of pro forma OATT obligations. For example, the Commission requires transmission providers to post specific performance metrics related to their completion of studies required to evaluate certain transmission requests under the *pro forma* OATT.

What is an OATT?

Most OATTs are modeled after the FERC pro forma tariff. FERC-jurisdictional utilities are required to file their OATTs under Section 205 of the Federal Power Act. An OATT filing would typically include the basis for the rates that are set forth in the tariff. Affected parties are afforded certain rights under the Federal Power Act to intervene in the filing. After a lengthy review process, FERC makes a ruling on the filing.

Transmission owners can change their rates as needed pursuant to a Section 205 filing. In cases where FERC has previously approved a formula rate for the derivation of the transmission rate (i.e., the transmission rate is updated annually), FERC may require an annual informational filing.

Order No. 888 provided that a non-jurisdictional transmission owner could establish an OATT that substantially conforms to, or is superior to, the pro forma tariff. In addition, a non-jurisdictional transmission owner could, but was not required to, file its non-jurisdictional tariff with FERC.

The FERC pro forma OATT generally includes terms and conditions for point-to-point and network integration transmission services, including common service provisions for such services. There are also several schedules that set forth the rates and terms for transmission service, ancillary services, and losses. In addition, there are several attachments that are included as part of the OATT that are related to transmission service, including an attachment for the transmission planning process and attachments for the large and small generator interconnection procedures and agreement.

What is Attachment K?

In Order No. 890, FERC amended its regulations and adopted reforms to the pro forma OATT in order to, among other things, increase transparency in the rules applicable to planning and use of the transmission system. To accomplish this objective, FERC required the development of regional planning processes that limit the opportunities for undue discrimination and ensure that comparable transmission service is provided by all public utility transmission providers. FERC required that each public utility transmission provider submit, as part of a compliance filing pursuant to Section 206 of the Federal Power Act, a proposal for a coordinated and regional planning process that complies with nine planning principals: coordination, openness, transparency, information exchange, comparability, dispute resolution, regional participation, economic and congestion studies, and cost allocation. These principals are set forth in Attachment K of the FERC pro forma OATT, therefore, the reference to the "Attachment K – Transmission Planning Process." Note that not all public utilities transmission providers have designated their OATT attachment references to be the same as that set forth in the FERC pro forma OATT. For example, Xcel Energy's transmission planning process is set forth in Attachment R to their OATT.

All FERC-jurisdictional utilities (i.e., PSCo and Black Hills Energy) must comply with this requirement. As previously discussed, FERC-jurisdictional utilities may deny transmission service to non-jurisdictional utilities that do not voluntarily conform to FERC Orders (including the transmission planning process set forth in the orders). It is our understanding that Colorado Springs Utilities and WAPA, which are non-jurisdictional utilities, have filed a "safe harbor" OATT that includes an "Attachment K – Transmission Planning Process."

Point-to-Point and Network Service Transmission Rates

The annual transmission revenue requirement is the same for both point-to-point and network transmission service, but the cost is assessed differently for each of the services.

A network transmission customer is assessed a monthly demand charge, which is determined by multiplying its load ratio share times one-twelfth (1/12) of the transmission provider's annual transmission revenue requirement.

A point-to-point transmission customer is assessed a monthly charge based on the transmission customer's reserved capacity multiplied by the transmission provider's applicable firm or non-firm point-to-point transmission rate. The monthly transmission rate is determined by dividing one-twelfth (1/12) of the transmission provider's annual transmission revenue requirement by the appropriate transmission system load divisor as authorized by FERC (i.e., monthly peak load and average monthly coincident peak loads).

6.2 Jurisdictional Issues

6.2.1 Federal Jurisdiction

The provision of transmission service in the US takes the form of a market structure generally considered a natural monopoly. Therefore, federal and/or state governments regulate transmission service to prevent market abuse and to balance the needs of consumers, the public interest, as well as the transmission company and its shareholders through rate proceedings and protocol. In many areas of the US, the federal government through FERC, and state governments through each state's Public Service Commission (or other such similar entity), have authority over the transmission service rate setting process. However, because of the interconnected nature of electric grids (including Colorado's) with other states and regions, only FERC has regulatory jurisdiction over the rate setting process for wholesale interstate electric transmission service. Colorado's FERC jurisdictional utilities (as described below) that are currently participating or intend to participate in regional import/export markets will have their transmission rate setting process subject to the purview of FERC.

IOUs, such as PSCo and Black Hills Energy in Colorado, which own transmission facilities that are utilized in the provision of wholesale interstate electric transmission service, are considered "FERC jurisdictional" utilities. FERC jurisdictional utilities must satisfy the rate filing and review provisions in Sections 205 and 206 of the Federal Power Act. In other words, FERC's jurisdictional utilities rate-setting process, including the terms and conditions of such service, are subject to review and approval by FERC.

There are three other types of transmission-owning utilities that generally are not subject to FERC jurisdiction (commonly referred to as "non-jurisdictional utilities"), except for the reciprocity provisions discussed in the "FERC Reciprocity Rule" section of this report. These non-jurisdictional utilities consist of:

- Rural Electric Cooperative Associations, such as Tri-State.
- Munis or municipal power or joint-action agencies, such as the Platte River Power Authority and Arkansas Power River Authority.
- Federal power marketing agencies, such as WAPA.

6.2.2 State Jurisdiction

Notwithstanding the FERC rate regulation discussed above, the respective states and other non-FERC governmental entities currently have jurisdiction over the siting and permitting of transmission infrastructure projects within the states. There is current legislation by Senators Bingaman[69] and Reid[70] being proposed in the US Congress that would provide the federal government siting authority over interstate transmission projects to allow for greater access to renewable resources. In addition, federal legislation is also being considered that would open up the planning process to regional transmission organizations and utilities that successfully initiate an interconnection-wide planning process. The proposed legislation directs FERC to coordinate the assortment of regional planning efforts that have emerged in the east and west to agree on interconnection-wide plans. Federal regulators would then defer to a planning entity that emerges out of that process. The final outcome of such legislation is not known at this time.

Public utilities that serve retail customers, such as the IOUs, are subject to having their retail rates reviewed and approved by the state PUCs. As such, transmission costs that are a component of retail rates are subject to review and approval by the PUCs.

6.3 Outline of Current Federal Energy Regulatory Commission Process

6.3.1 Review of Federal Energy Regulatory Commission Jurisdiction

The US has a complex and multi-jurisdictional system of transmission investment recovery through regulated rates. In general, FERC regulates interstate electric

69 Senate Bill 539, introduced on March 5, 2009.
70 United States Senate Committee on Energy and Natural Resources, Press Release, March 20, 2009.

wholesale transactions and sets wholesale transmission tariffs. On the other hand, state regulatory commissions (in case of Colorado, the CPUC) set the bundled retail rates in their states for the entities under their jurisdictions, through which transmission costs are recovered from customers in the utility territories.

The federal or state or combined jurisdiction depends on the structure and ownership of transmission entities:

- IOUs: Subject to both state and FERC regulation.
- Merchant power and transmission entities are subject to FERC jurisdiction.
- Federal power marketing administrations, such as Bonneville Power Administration and WAPA are not subject to either FERC or state regulations.
- Local government entities such as Munis, public utility districts, rural cooperatives, generation and transmission associations, are non-jurisdictional entities that are not subject to FERC or state jurisdiction for most purposes.

Nevertheless, many non-jurisdictional entities follow FERC rules by voluntary choice or under reciprocity provisions.

FERC has jurisdiction over wholesale transmission rates of most investor-owned transmission systems in the US (i.e., public utilities), since transmission systems generally cross state lines, making electricity an interstate commodity in an interstate trade, thus necessitating federal jurisdiction. Exceptions to FERC jurisdictions are the transmission grids in Hawaii, Alaska, and Texas. Transmission grids in Hawaii and Alaska are geographically isolated from the main interconnections in the US. In Texas, a substantial part of the system is a stand-alone interconnect and is not synchronically connected to either the Western or the Eastern Interconnection in the US. In addition, one-third of US transmission is not owned by public utilities, and therefore, are not subject to full FERC wholesale regulation.

Transmission companies who invest in transmission development generally have the right to recover their investments through rates. Such companies prepare and submit their transmission rates to FERC for approval. In certain areas where RTOs have been established, either or both transmission owners are RTOs and can prepare and submit rates to FERC for approval.

In addition to pricing transmission lines, FERC also maintains jurisdiction over the terms and conditions for using them. For instance, FERC requires that transmission-owning companies offer their customers access to the transmission system under the same terms and conditions as they would offer it to themselves. FERC also required utilities that owned both power plants and transmission lines to separate those activities into different businesses. FERC authorized this separation to prevent the transmission portion of a utility's business from discriminating in favor of its own generators and against other companies that want access to the transmission system.

In general, FERC jurisdiction does not cover:

- Public Power Entities: Public power entities such as the New York Power Authority, Arizona's Salt River Project, North Carolina's Santee Cooper, or the Los Angeles Department of Water and Power are not under FERC jurisdiction.

- Federal agencies also self-govern, so the Bonneville Power Administration, the WAPA, and the Tennessee Valley Authority all fall outside FERC's authority. Finally, most of Texas and all of Hawaii and Alaska are outside FERC jurisdiction because they are not connected, or not tightly connected, to the interstate transmission grid.
- Retail rates, where in general, states have jurisdiction in contrast to the wholesale rates where federal government exercises jurisdiction.
- Distribution lines, where in general, states have jurisdiction over the part of the system that serve the end use customers directly, although a clear demarcation of boundary between distribution and transmission systems, by function or size, is still debatable.

The FERC regulation of the interstate wholesale transmission rates for public utilities follows the General Ratemaking Principles, which assure rates and terms are just and reasonable and not unduly discriminatory. The rate regulations are driven by embedded system costs, based on "cost of service" principles," not cost of serving the next user.

Therefore, in the state of Colorado, FERC has jurisdiction over PSCo and Black Hills Energy as IOUs, but not on REAs and generation and transmission associations such as Tri-State, or Munis, such as Colorado Springs Utilities and Fort Collins Utilities, or the Federal Power Marketing Administration, i.e., WAPA.

6.3.2 Federal Energy Regulatory Commission Reciprocity Rule

Pursuant to Order No. 888, FERC directed all jurisdictional transmission owners to establish an OATT. FERC's order was not extended to non-jurisdictional transmission owners. However, FERC did determine that a non-jurisdictional transmission owner's ability to take open access transmission service from a jurisdictional transmission owner could be conditioned upon the agreement of the non-jurisdictional utility to offer reciprocal transmission service in return. In other words, a non-jurisdictional transmission owner that takes service from a jurisdictional transmission provider could be required to provide reciprocal transmission service.

Order No. 888 identified three mechanisms that non-jurisdictional transmission owners could use to meet their reciprocity obligations:

- Establish an OATT that substantially conforms to or is superior to the pro forma OATT.
- Enter into a bilateral agreement.
- Obtain a waiver of its reciprocity obligation.

Non-jurisdictional transmission owners that chose to establish an OATT could, but were not required to, file their tariffs with FERC. Non-jurisdictional transmission owners with tariffs that FERC has approved under its "safe harbor" construction could not be refused open access transmission service by a jurisdictional transmission provider on the basis that the non-jurisdictional transmission owner did not have a reciprocal obligation. At least one non-jurisdictional transmission owner in Colorado has a FERC-approved “safe harbor” OATT in place.

In addition, the EPAct 2005 enacted a new section under the Federal Power Act that authorized FERC to require non-jurisdictional transmission owners to provide transmission service under comparable terms and conditions that the non-jurisdictional transmission owners apply to themselves, and that are not unduly discriminatory or preferential. Furthermore, the rates for that service must be comparable to the rates that the non-jurisdictional transmission owners charge themselves.

6.3.3 Review of Amount of Transmission that is Federal Energy Regulatory Commission Jurisdictional in terms of Rate Recovery

FERC jurisdiction with regards to rate recovery applies to public utilities, or more specifically, to IOUs, which in Colorado include PSCo and Black Hills Energy.

PSCo operates in Colorado, and owns approximately 4,000 circuit miles of transmission lines 69 kV and above.[71]

BH/Colorado Electric Utility Company is the Black Hills Energy electric utility in southeastern Colorado serving approximately 92,000 electric customers.[72] The BH/Colorado Electric Utility Company transmission system consists of 194 miles of 115-kV transmission lines.[73]

6.3.4 Review of Federal Energy Regulatory Commission Process and Incentives

FERC has established rules to bolster investment in the nation's transmission infrastructure and to promote electric power reliability and lower costs for consumers by reducing transmission congestion.[74] The rules identify specific incentives the Commission would allow based on a case-by-case review and analysis of individual transmission proposals.

EPAct 2005 directed the Commission to develop incentive-based rate treatments for transmission of electric energy in interstate commerce, adding a new section 219 to the Federal Power Act. The rule implemented this new statutory directive through the following incentive-based rate treatments:

- Incentive rates of return on equity for new investment by public utilities (both traditional utilities and stand-alone transmission companies).

[71] http://www.xcelenergy.com/SiteCollectionDocuments/docs/OATTOrder890Filing12-07-07.pdf

[72] http://www.blackhillscorp.com/RFP/040109BidderMeetingPresentation.pdf

[73] http://www.blackhillscorp.com/trasmission/Stakeholder_Meeting_Presentation_42209.pdf

[74] http://www.ferc.gov/industries/electric/indus-act/trans-invest.asp

- Full recovery of prudently incurred construction work in progress.
- Full recovery of prudently incurred pre-operations costs.
- Full recovery of prudently incurred costs of abandoned facilities.
- Use of hypothetical capital structures.
- Accumulated deferred income taxes for transmission companies.
- Adjustments to book value for transmission companies sales/purchases.
- Accelerated depreciation.
- Deferred cost recovery for utilities with retail rate freezes.
- A higher rate of return on equity for utilities that join and/or continue to be members of transmission organizations, such as (but not limited to) regional transmission organizations and independent system operators.

All rates approved under the rules are subject to Federal Power Act rate filing standards. The rule allows utilities on a case-by-case basis to select and justify the package of incentives needed to support new investment. Additionally, the rule provides expedited procedures for the approval of incentives to provide utilities greater regulatory certainty and facilitate the financing of projects. The rule became effective on September 29, 2006.

6.3.5 Financial Incentives Authorized by Federal Energy Regulatory Commission

In recent years, FERC, highlighting the importance of the transmission infrastructure to the successful development of competitive wholesale markets, has proposed various financial incentives to foster and promote investment in the expansion of the transmission grid in the US.

One of the earliest FERC actions, with a focus on the western regions, was on May 16, 2001, when the FERC issued its “Further Order on Removing Obstacles… in the Western United States.”[75] The impetus for the FERC action was the recognition of the role of transmission constraints in destabilizing markets in California and elsewhere in the west. To encourage rapid construction of transmission capacity and generator interconnection with the grid, the FERC authorized a program of temporary financial incentives. This first use of financial incentives for transmission infrastructure allowed premiums on equity returns on equity of 1.0 to 2.0 percent on various project types with depreciation lives of 10 to 15 years, subject to specified in-service dates.

[75] Order Removing Obstacles to Increased Electric Generation and Natural Gas Supply in the Western United States and Requesting Comments on Further Actions to Increase Energy Supply and Decrease Energy Consumption, 94 FERC ¶ 61,272 (2001).

Further Order on Removing Obstacles to Increased Energy Supply and Reduced Demand in the Western United States and Dismissing Petition for Rehearing, 95 FERC ¶ 61,225 (2001).

6.3.6 Federal Energy Regulatory Commission's Nexus Test

FERC uses a "Nexus" Test to determine if projects qualify for incentives.[76]

> "In addition to satisfying the section 219 requirement, an applicant must demonstrate that there is a nexus between the incentive sought and the investment being made. The Commission has stated that in evaluating whether an applicant has satisfied the required nexus test, the Commission will examine the total package of incentives being sought, the inter-relationship between any incentives, and how any requested incentives address the risks and challenges faced by the applicant in constructing the project. Applicants must provide sufficient explanation and support to allow the Commission to evaluate the incentives. In addition, the Commission has clarified that it retains the discretion to grant incentives that promote particular policy objectives unrelated to whether or not a project presents specific economic risks or challenges." From July 24, 2007 order, Para. 46."

6.3.7 New Federal Energy Regulatory Commission Incentives

On October 6, 2008, FERC approved rate incentives for a major transmission project in the west that will deliver up to 3,000 Megawatts of capacity from location-constrained renewable resources to distant load centers.[77]

The first project, known as the Energy Gateway Transmission Expansion Project, has been characterized as one of the most ambitious electric infrastructure projects planned in the western US in the past two decades. The project's sponsor, PacifiCorp, asked FERC for a 2.5 percent adder to its base return on equity (ROE) and recovery of prudently incurred abandonment costs for the $6 billion project. The Commission granted PacifiCorp a 2 percent adder to its base ROE. The project involves eight segments covering portions of Nevada, Idaho, Oregon, Utah, Washington, and Wyoming and is planned to go on-line between 2010 and 2014.

With the exception of one segment of the project running from Washington to Oregon, FERC said that "PacifiCorp has adequately demonstrated that the project will ensure reliability and reduce transmission congestion" and thus meets Federal Power Act requirements. The remaining seven segments "would establish for the first time a backbone of 500-kV transmission lines in PacifiCorp's Wyoming, Idaho and Utah regions," FERC said, and provide "a platform for integrating and coordinating future regional and Sub-regional electric transmission projects being considered in the Pacific Northwest and the Intermountain West."

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[76] http://www.westgov.org/wieb/meetings/crepcsprg2009/briefing/FERCirr.pdf

[77] http://www.ferc.gov/EventCalendar/Files/20081016104244-E-26-31-PR.pdf

6.3.8 Federal Energy Regulatory Commission Rate Recovery Incentives

In 2006, FERC passed the final rule on "Promoting Transmission Investment Through Pricing Reform" to establish various incentive-based rate treatments for interstate transmission. Although the Commission noted that promotion of renewable energy projects supports certain policy objectives, the final rule does not extend to adoption of separate rate-based incentives for renewable energy projects. The final rule does, however, describe eight incentive-based rate treatments that will be considered for any transmission project for all jurisdictional public utilities, including transmission companies. For completeness, we list these rate recovery principles here because they would be considered (but not guaranteed) in any FERC-regulated transmission investment to remotely located generation.

In allowing for recovery through rates, the Commission intends to consider:[78]

- Incentive-based ROE for building new transmission facilities that ensure reliability and reduce the cost of delivered power.
- Accelerated depreciation for new transmission facilities that ensure reliability and reduce the cost of delivered power.
- Overall rates of return based on hypothetical capital structures presented to the Commission as part of the approval process.
- Deferred recovery of new transmission investment costs by public utilities under retail freezes.
- Construction Work In Progress (CWIP) through the inclusion of 100 percent of CWIP in the calculation of transmission rates.
- Abandoned investment through the inclusion of 100 percent of costs of abandoned transmission facilities in transmission rates if such abandonment is outside the control of management.
- Single-issue rate making.

All rates approved under the final rule are subject to Federal Power Act rate filing standards. The rule allows utilities on a case-by-case basis to select and justify the package of incentives needed to support new investment. These rate recovery incentives are being used in the development of transmission for remotely located generation. For example, Pacific Gas and Electric Company filed a petition for a declaratory order on December 21, 2007. Their petition sought incentive rate treatment under Order No. 679 for a proposed transmission project from Canada to northern California with capacity of up to 3,000 MW. Pacific Gas and Electric Company claimed that this transmission investment would enable integration of renewable energy resources and help various parties in the west to meet state RPS and greenhouse gas reduction goals, along with reliability and development goals. FERC granted the petition; and with its Order on April 21, 2008, allowed the company to

[78] FERC ¶61,057, final rule, "Promoting Transmission Investment through Pricing Reform," July 20, 2006.

recover prudently incurred pre-commercial costs related to the Project and prudently incurred abandonment costs if Pacific Gas and Electric Company cancels the project for reasons beyond their control.

Additional incentives granted specifically to transmission providers include return on equity incentives, accumulated deferred income taxes, acquisition premiums for an independent transmission company formation, and merchant transmission incentives.

6.3.9 Order No. 679 on Incentives

In the EPAct 2005, the US Congress modified the Federal Power Act to add Section 219 and directed FERC to establish rules providing incentives to promote capital investment in transmission infrastructure. FERC subsequently issued Order No. 679, setting forth the processes by which a public utility may seek transmission rate incentives pursuant to Section 219.

Pursuant to Section 219, an applicant for transmission rate incentives must show that “the facilities for which it seeks incentives either ensure reliability or reduce the cost of delivered power by reducing transmission congestion.” Also, as part of this demonstration, “Section 219(d) provides that all rates approved under the Rule are subject to the requirements of Sections 205 and 206 of the Federal Power Act, which require that all rates, charges, terms and conditions be just and reasonable and not unduly discriminatory or preferential.”

Order No. 679 provides that a public utility may file a petition for declaratory order of a Section 205 filing to obtain incentive rate treatment for transmission infrastructure investment that satisfies the requirements of Section 219 (i.e., the applicant must demonstrate that the facilities for which it seeks incentives either ensure reliability and/or reduce the cost of delivered power by reducing transmission congestion). Order No. 679 established a process for an applicant to follow to demonstrate that it meets this standard, including a rebuttable presumption that the standard is met if:

- The transmission project results from a fair and open regional planning process that considers and evaluates projects for reliability and/or congestion and is found to be acceptable to FERC.
- The transmission project has received construction approval from an appropriate state commission or state siting authority.

Order No. 679-A clarifies the operation of this rebuttable presumption by noting that the authorities and/or processes on which it is based (i.e., a regional planning process, a state commission, or siting authority) must, in fact, consider whether the project ensures reliability or reduces the cost of delivered power by reducing congestion.

Since inception of Order 679, FERC has ordered incentive rate treatment for numerous transmission projects. These incentives have included:

- Inclusion of 100 percent of CWIP in rate base.
- Recovery of abandonment costs in the event the transmission project is cancelled for reasons that are beyond the control of the transmission owner.

- Recovery of preconstruction, start-up, and development costs through the establishment of a regulatory asset.
- ROE adders for RTO membership, formation of an independent transmission company, and use of advanced technologies.
- Use of hypothetical capital structure during the construction phase.

The following list provides a description of the most recent projects and the types of incentive rate treatments that have been granted by FERC[79] by the date of the Order.

Green Power Express LP

April 10, 2009, Docket No. ER09-681-000: The Commission approved transmission infrastructure investment rate incentives for a proposed 3,000-mile regional "green power superhighway" designed to deliver wind-powered renewable energy from the upper Midwest to consumers in and around Chicago, Minneapolis, and other load centers. Green Power Express LP estimates that its proposed 765-kV transmission network would cost between $10 and $12 billion, eventually span 7 states, and deliver up to 12,000 MW of wind energy and stored energy from the Dakotas, Minnesota, and Iowa to Midwestern load centers in Chicago, Minneapolis, and southeastern Wisconsin. The Commission granted Green Power Express LP's request to:

- Recover abandonment costs.
- Establish a regulatory asset that would defer recovery of pre-construction costs as well as start up and development costs
- Allow 100 percent of CWIP in rate base.
- Use a hypothetical capital structure.
- Use a 10-basis point adder in recognition of the size, scope, benefits, risk, and challenges of the project.
- Use a 50-basis point adder for participation in an RTO.
- Use a 100-basis point adder for status as an independent transmission company.
- ROE of 12.38 percent inclusive of the 160-basis point incentive adders.

Pioneer Transmission, LLC

March 30, 2009, Docket No. ER09-75-000: The Commission addressed Pioneer Transmission, LLC's request for transmission rate incentives for a proposed 240-mile transmission project consisting of a 765-kV transmission line in Indiana that will connect the PJM and MISO systems. This order establishes the first ROE for a cross-regional transmission organization project. Specifically, the Commission:

- Established a base ROE of 10.54 percent.

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[79] For a more complete and updated list, visit FERC's Web site at http://www.ferc.gov/industries/electric/indus-act/trans-invest/orders.asp

- Approved a ROE adder of 50-basis points for membership in a RTO.
- Approved a ROE adder of 150-basis points for new transmission, but stated that the ROE will not go into effect unless and until the project is approved by the regional transmission planning processes of PJM and MISO and there is a Commission-approved cost allocation methodology in place, as acknowledged by Pioneer.
- Denied a ROE adder for advanced technologies.
- Approved a CWIP incentive, but stated that the 100 percent inclusion of CWIP in rate base will not go into effect unless and until the project is approved by the regional transmission planning processes of PJM and MISO and there is a Commission-approved cost-allocation methodology in place, as acknowledged by Pioneer Transmission, LLC.
- Approved abandonment and regulatory asset incentives.
- Established settlement and hearing procedures for certain formula rate issues.

ITC Great Plains

March 16, 2009, Docket No. ER09-548-000: The Commission approved transmission rate incentives for two transmission projects proposed by ITC Great Plains, LLC, the Kansas Electric Transmission Authority Project and the Kansas V Plan, to be built in the Southwest Power Pool, Inc. (SPP) region, but set the company's formula rates and rate protocols for hearing. The Commission approved the requested 100 percent CWIP included in the rate base, abandoned plant incentive, a regulatory asset to provide for the recovery of start-up and development costs of the projects, beginning on the in-service date of the projects, and return on equity adders including 100-basis points for independent transmission companies and 50-basis point adders for RTO membership.

Public Service Electric and Gas Company

March 13, 2009, Docket No. ER09-249-000: The Commission granted Public Service Electric and Gas Company authorization for a 150-basis points ROE transmission rate incentive as applicable to the company's portion of the Mid-Atlantic Power Pathway Project. The Commission also granted Public Service Electric and Gas Company authorization to recover 100 percent of all prudently incurred development and construction costs if this project is abandoned or cancelled for reasons beyond the company's control.

Northeast Utilities Service Company

January 16, 2009, Docket No. ER08-966-001: The Commission denied rehearing of an order which granted Northeast Utilities Service Company's request for a waiver of the December 31, 2008 deadline for receiving a 100-basis point transmission incentive under Opinion No. 489 for regional transmission expansion plan-approved transmission projects, and its request for an additional 50-basis point incentive for using advanced transmission technologies. The Commission affirmed its prior conclusion that good cause existed to waive the deadline so that Northeast Utilities Service Company could complete testing on the Middletown-to-Norwalk Project and continue to qualify for a 100-basis point incentive. The Commission also affirmed its conclusion to allow an additional 50-basis point incentive for using advanced transmission technologies.

Tallgrass Transmission and Prairie Wind Transmission

December 2, 2008, Docket No. ER09-35-000 and ER09-36-000: The Commission addressed revised tariff sheets to recover the costs of certain high-voltage transmission projects. Tallgrass Transmission and Prairie Wind Transmission plan to build in the SPP region and have requested rate incentives for their investments in the proposed projects. Tallgrass Transmission proposes to construct, at an estimated cost of approximately $500 million, a 765-kV transmission project in Oklahoma. Prairie Wind Transmission proposes to construct, at an estimated cost of approximately $600 million, a 765-kV transmission project in Kansas. The Commission approved a 1.5 percent adder for each of the projects, and up to 0.5 percent of incentive ROE for participation in the SPP when the two companies become members of SPP and their projects are placed under the SPP's operation control, as well as inclusion of 100 percent of CWIP in rate base and recovery of prudently incurred abandonment costs.

Northeast Utilities Service Company and National Grid

November 17, 2008, Docket No. ER08-1548-000: The Commission authorized (1) an incentive ROE of 125-basis points; (2) inclusion of 100 percent CWIP costs in rate base; and (3) recovery of 100 percent of prudently incurred costs if the project is abandoned for reasons beyond the control of Applicants for the New England East-West Solution Project. The project, with an overall estimated cost of $2.1 billion, is a complex addition to the New England 345-kilovolt transmission system aimed at substantially improving the reliability of electric transmission service in southern New England.

PacifiCorp

October 21, 2008, Docket No. EL08-75-000: The Commission granted in part, and denied in part, a petition for declaratory order seeking incentive rate treatment for PacifiCorp's Energy Gateway Transmission Expansion Project. The project involves eight segments covering portions of Nevada, Idaho, Oregon, Utah, Washington, and Wyoming and is planned to go on-line between 2010 and 2014. The project will deliver up to 3,000 MW of capacity from location-constrained renewable resources to distant load centers.

New York Regional Interconnection, Inc.

September 18, 2008, Docket No. EL08-39-000: The Commission granted in part, and denied in part, New York Regional Interconnect, Inc.'s request for certain incentives for a proposed 1,200 MW transmission line to span 190 miles between Marcy and New Windsor, New York. Specifically, the Commission conditionally approved 300-basis points of ROE incentives for the project. The 300-basis points of ROE incentives consist of the following: 50-basis for future participation in the New York Independent System Operator, Inc; 100-basis points for forming an independent transmission company, and 150-basis points for a combined transmission and advanced technology incentive. The approval for these incentives is conditioned on the New York Public Service Commission finding that the project will ensure reliability or reduce congestion and granting siting approval.

6.4 Federal Loan Guarantee Programs and Others

Title XVII of the EPAct 2005 authorized the DOE to issue loan guarantees for projects that "avoid, reduce or sequester air pollutants or anthropogenic emissions of greenhouse gases; and employ new or significantly improved technologies as compared to commercial technologies in service in the United States at the time the guarantee is issued."[80] The loan guarantee program was authorized to offer more than $10 billion in loan guarantees for energy efficiency, renewable energy, and advanced transmission and distribution projects. The authority to issue loan guarantees granted by EPAct 2005 expires on September 30, 2009.

Temporary Loan Guarantee Program

The American Recovery and Reinvestment Act of 2009 (H.R. 1), enacted in February 2009, extended the authority of the DOE to issue loan guarantees and appropriated $6 billion for this program. Under this act, the DOE may enter into guarantees until September 30, 2011. The act amended the EPAct 2005 by adding a new section defining eligible technologies for new loan guarantees. Eligible projects include renewable energy projects that generate electricity or thermal energy and facilities that manufacture related components, electric power transmission systems, and innovative biofuel projects. Funding for biofuel projects is limited to $500 million. Davis-Bacon wage requirements[81] apply to any project receiving a loan guarantee.

The American Recovery and Reinvestment Act of 2009 modified this program to provide for a targeted and time-limited stimulus for commercial as well as innovative renewable energy development and manufacturing.[82] This modification is called the "Temporary Program for Rapid Deployment of Renewable Energy and Electric Power Transmission Projects." Loan guarantees under this temporary program do not require payment of a credit subsidy cost. As set forth in he American Recovery and Reinvestment Act of 2009, the federal government will pay the full credit support costs of guarantees issued under the Temporary Project, thereby eliminating upfront payment by the beneficiary to the government for the cost of the guarantee. Six billion dollars was allocated under the recovery act to underwrite these costs.

The "Temporary Program for Rapid Deployment of Renewable Energy and Electric Power Transmission Projects" also provides for guarantees in support of the following three expanded categories of projects:

[80] http://www.dsireusa.org/library/includes/printincentive.cfm?incentive_code=US48F

[81] http://www.dol.gov/compliance/laws/comp-dbra.htm

[82] http://www.mondaq.com/article.asp?articleid=75440

- Renewable energy systems, including incremental hydropower, that generate electricity or thermal energy, and facilities that manufacture related components.
- Electric power transmission systems, including upgrading and reconductoring projects.
- Leading-edge biofuel projects that will use technologies performing at the pilot or demonstration scale that the Secretary of Energy determines are likely to become commercial technologies and will produce transportation fuels that substantially reduce life-cycle greenhouse gas emissions compared with other transportation fuels.

Under the American Recovery and Reinvestment Act of 2009, these expansive changes are temporary. In order to qualify, a project must commence construction prior to September 30, 2011. Federal wage and other employment-related "strings" remain attached to projects that receive guarantees under this temporary program.

6.5 Rural Electric Program

The US Department of Agriculture's Rural Development's Electric Program provides leadership and capital to upgrade, expand, maintain, and replace the US' vast rural electric infrastructure.[83]

The program makes loans and loan guarantees to finance the construction of electric distribution, transmission and generation facilities, including system improvements and replacements required to furnish and improve electric service in rural areas, and for demand-side management, energy conservation programs, and on-grid and off-grid renewable energy systems.

Loans are made to corporations, states, territories, and subdivisions and agencies such as municipalities, public utility districts, and cooperative, nonprofit, limited-dividend, or mutual associations that provide retail electric service needs to rural areas or supply the power needs of distribution borrowers in rural areas. Financial assistance is also available to rural communities with extremely high energy costs to acquire, construct, extend, upgrade, and otherwise improve energy generation, transmission, or distribution facilities.

6.6 Tax Exempt Financing

Tax-exempt bonds are used by state and local governments to finance public capital improvements and other projects, subject to certain limits on private use of the projects and the debt service backing from private resources. The conditions imposed by the government restrict the prospect for transmission open access on facilities financed by the use of tax-exempt bonds. To address this issue, we present the following exposition on the tax treatment of transmission investments, taken almost

[83] "USDA Colorado Rural Development" http://www.rurdev.usda.gov/CO/Pubs/RDProgramsBCPJune2008.pdf

verbatim, from the "Financing Electricity Transmission, Expansion in the West," A Report to the WGA, February 2002.[84]

6.6.1 Tax Treatment of Transmission Investments

Present Law

Tax-exempt bonds are a useful tool to finance power projects. Under present law, two different categories of tax-exempt bonds can be issued to finance electric transmission facilities, "government use" bonds and "exempt facility" private activity bonds. Tax-exempt "government use" bonds can be issued to finance a transmission facility that is owned and used by a state or a political subdivision of a state.

A state or local government may also issue tax-exempt "government use" bonds to finance its ownership interest in a transmission facility that it jointly owns with others, including non-governmental utilities. The "private business use" of a transmission facility (i.e., the portion of the facility that is used by an entity that is not a state or a political subdivision) that is financed with "government use" bonds cannot exceed the lesser of 10 percent of its capability or $15 million.

Private business use includes use by federal agencies (such as Bonneville Power Administration and WAPA), IOUs, marketers, non-profit cooperatives and any other nongovernmental entity. The applicable US Department of the Treasury regulations contain highly technical provisions that must be used to measure the private business use of transmission facilities.

"Exempt facility" private activity bonds may be issued to finance facilities for the local furnishing of electricity, regardless of whether these facilities are owned or used by nongovernmental utilities. These bonds are of very limited usefulness because of the requirement in present law that the financed facility and its owners and users provide electric service to an area that is no larger than two adjacent counties.

Current US Department of the Treasury Regulations

Under present law, these rules limit the extent to which state and local governmental units that own transmission facilities financed by tax-exempt bonds are allowed to permit non-governmental entities to use those facilities. Nationally, 8 percent of transmission is owned by public power. In some states, the percentage is much higher. For example, in California about 25 percent of the transmission is owned by Munis or governmental entities.

Prior to 1998, the private use rules essentially barred public power from committing to provide full open access transmission and from joining RTOs. Temporary regulations issued by the US Department of the Treasury in 1998 and reissued in 2001, provided partial temporary relief from these rules. But because the rules are only temporary,

[84] Material in this section are based on "Financing Electricity Transmission, Expansion in the West", A Report to the Western Governors, February 2002
http://www.westgov.org/wga/initiatives/energy/final_rpt.pdf

they do not permit public power entities to make long-term commitments to provide open access transmission service and to join RTOs when they are formed. More importantly, under the temporary regulations, no real relief is available for new transmission facilities financed by recently issued tax-exempt bonds. If the transmission facilities are reasonably expected to be used to provide open access transmission service, tax-exempt bonds cannot be used.

So for the needed transmission infrastructure that will benefit all transmission users in an open access or RTO structure, the current US Department of the Treasury regulations restrict a significant segment of possible transmission developers and their source of capital. Therefore, the current temporary regulations deter rather than encourage expansion of the grid. Congressional action or action by the IRS to make the temporary rules permanent is needed to cure this problem.

Extended Use of Tax Exempt Bonds

The Internal Revenue Code could be amended to create a new category of "exempt facility" bond that can be issued on a tax-exempt basis to finance transmission facilities.

These bonds could be issued under the following conditions:

- The transmission facilities to be financed would be approved by the applicable regional transmission organization, as necessary.
- The financed facilities would be available to users on a non-discriminatory basis under applicable open-access requirements.
- The total dollar amount of exempt facility bonds for transmission facilities would be subject to a separate annual state-by-state volume cap limit that could be combined by states participating in regional transmission projects and/or combined over a period of years to provide sufficient financing for large projects.

The requirement that the financed facilities be approved by an RTO or other regional authority would ensure that only those projects that are truly necessary from a regional perspective would benefit from tax exempt financing. The requirements that the financed transmission facilities should be available to subscribers and others under nondiscriminatory open access terms ensure that special benefits would not be passed through to any party.

The benefits of tax exempt financing would be available to those willing to invest in transmission, including investor-owned, cooperative, and government utilities and builders of merchant transmission lines, provided access was made available to all parties on a non-discriminatory basis. The special volume cap requirements could be used to limit the total dollar amount of tax-exempt debt that is issued for transmission projects and to quantify the costs to the US Department of the Treasury.

6.7 Renewable Electricity Production Tax Credit

The federal renewable energy production tax credit was created under the Energy Policy Act of 1992 and was originally applied to energy production from wind farms.

Renewable energy production tax credit is a per-kilowatt-hour tax credit for electricity generated by qualified energy resources and sold by the taxpayer to an unrelated person during the taxable year.

The starting renewable energy production tax credit was 1.5 cents/kWh in 1993, to be adjusted annually for inflation. Since its inception, renewable energy production tax credit has expired and been renewed several times, with its eligibility requirements broadened to include solar, geothermal, and biomass electricity production as well as some other less common forms of renewable electricity generation, such as bio-digesters. The most recent extensions were in October 2008 and again in February 2009.

The October 2008 legislation extended the in-service deadlines for all qualifying renewable technologies and expanded the list of qualifying resources to include other novel technologies and made changes to the definitions of several qualifying resources and facilities.

The February 2009 legislation revised the credit by: (1) extending the in-service deadline for most eligible technologies by three years (two years for marine and hydrokinetic resources); and (2) allowing wind project developers to choose to receive a 30 percent investment tax credit in place of the renewable energy production tax credit for facilities placed in service in 2009 and 2010, and also for facilities placed in service before 2013, if construction begins before the end of 2010. The investment tax credit then qualifies to be converted to a grant from the US Department of the Treasury. The US Department of the Treasury must pay the grant within 60 days of when an application is submitted.

The rules governing the renewable energy production tax credit vary by resource and facility type. Table 6-1 provides a summary of the latest rules on the in-service deadlines and the renewable energy production tax credit amount for different resource types. The table includes changes made in the law on February 17, 2009. The inflation-adjusted credit amounts are current for the 2008 tax year.

Table 6-1. In-Service Deadline and Credit Amounts by Resource Type

Resource Type	In-Service Deadline	Credit Amount
Wind	December 31, 2012	2.1¢/kWh
Closed-Loop Biomass	December 31, 2013	2.1¢/kWh
Open-Loop Biomass	December 31, 2013	1.0¢/kWh
Geothermal Energy	December 31, 2013	2.1¢/kWh
Landfill Gas	December 31, 2013	1.0¢/kWh
Municipal Solid Waste	December 31, 2013	1.0¢/kWh
Qualified Hydroelectric	December 31, 2013	1.0¢/kWh
Marine and Hydrokinetic (150 kW or larger)	December 31, 2013	1.0¢/kWh

Source: http://www.direusa.org.

The duration of the credit is generally 10 years after the date the facility is placed in service, with some exceptions applied to open-loop biomass, geothermal, small irrigation hydro, landfill gas, and municipal solid waste combustion facilities.

In addition, the tax credit is reduced for projects that receive other federal tax credits, grants, tax-exempt financing, or subsidized energy financing.

A more detailed summary of the renewable energy production tax credit, its applicability, and its history is provided on the DSIRE Web site.[85]

85 http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=US13F&State=federal&currentpageid=1&ee=1&re=1

Section 7
Transmission Cost Recovery and Cost Allocation

7.1 Transmission Costs

Transmission is a small component of total delivered electricity cost. However, it is widely believed that the benefits of transmission development, in terms of elimination of congestion and access to less costly generation resources, would generally surpass the cost of transmission development.

Historically, the preponderance of vertically integrated natural monopoly power companies, that owned both generation and transmission and supplied their native load customers, would build and finance the needed transmission line, be the sole entity to which cost would be allocated, and would be allowed to recover the costs from its ultimate customers under the applicable regulatory oversight.

Although the industry itself has been transformed to the interplay of many stakeholders, including independent generation companies, regulated and merchant transmission companies, and marketers, it is still the ultimate customers who in one way or another pay for all of the transmission investments.

Due to the interconnected nature of the power grid, the benefits of new transmission development are sometimes shared by customers beyond the native load of the transmission owner. Conversely, a transmission system can be adversely affected by operations in neighboring systems, since power flow in transmission systems follow the path of least resistance subject to certain physical laws and cannot be necessarily forced to follow the so-called "contract path" specified by contracting parties, except in DC lines. Therefore, chances are that changes in generation and load in a system will result in spillage or routing of power flow into other interconnected systems, through what is commonly called loop flow, impacting flows and congestion in those other systems.

More recently due to the new structure of the power industry, in both RTO- and ISO-type markets, and the more traditional fragmented electricity markets, some transmission developments involve multiple transmission entities, with various ownership structures, including merchant transmission solely in the business of transmission.

Today, transmission accounts for between 5 and 10 percent of the cost of a delivered kilowatt hour, providing benefits that greatly outweigh its costs. Although transmission is a small component of total delivered electricity cost, investment in transmission has historically lagged behind the need for transmission compared to the investment in generation.

Admittedly, transmission development presents multi-faceted challenges unlike those in generation development and involves multitudes of hurdles in terms of planning, permitting, siting, and construction. An important hurdle to transmission development is the underlying economic viability of transmission investments. Therefore, determining who gets paid and who pays for transmission investments is of the utmost importance.

Table 7-1 provides estimated transmission development costs for different voltage sizes. There are many cost factors that impact transmission costs, including location and terrain related, rights-of-way, substations and interconnection, and control technology. Therefore, actual costs would vary by project.

Table 7-1. Transmission Development Costs

Voltage (kV)	Cost (Thousands of Dollars/Mile)	Capacity (MW)(1)	Cost (Millions of Dollars/GW-Mile)(1)
230	$2,076.5	500	$5.46
345	$2,539.4	967	$2.85
500	$4,328.2	2,040	$1.45
765	$6,577.6	5,000	$1.32

Notes:

Data comes from EEI's "Transmission Projects at a Glance," January 2008.

Projects that use underground lines, have more than three segments, or have significantly mixed voltage levels are excluded.

The cost of projects is assumed to be given in 2007 dollars unless specified, and has been adjusted using the 2007 to 2008 percentage change in the Handy-Whitman Index.

(1) Based on a subset of projects where capacity was reported. Gigawatt miles are calculated by multiplying the capacity of the line (in GW) times the length of the line (in miles).

Source: "Transforming America's Power Industry: The Investment Challenge 2010-2030", Prepared by: The Brattle Group, for: The Edison Foundation, November 2008. http://www.eei.org/ourissues/finance/Documents/Transforming_Americas_Power_Industry.pdf

7.2 Cost Allocation

Cost allocation is the process by which joint and common costs are allocated for accounting purposes, and in the regulated utility sector, the allocations provide the basis for cost recovery.

Cost recovery is the process of assigning allocated costs to rates, which are then recovered from the rate payers. The general principle of cost recovery is that "cost causers should pay costs."

Generally, the FERC cost allocation manual allocates costs based on relative use. Several RTOs, including the MISO and the CAISO, have developed cost allocation mechanisms for inclusion in their OATTs to address the funding of transmission facilities needed to integrate future generating resources (e.g. renewable resources) into the RTO transmission grid. For example, under the existing MISO OATT, transmission owners are permitted to recover the cost of new transmission facilities that have been added to support the future interconnection and integration of renewable resources (i.e., sized to support future generation facilities).

Upon the completion of the interconnection arrangements for the new generation resources, the owners of these resources are required to pay a portion of the costs of the facilities required to support the integration of their resources to the respective transmission owners. Therefore, the ownership costs associated with the payment received from the generation owners would no longer be recovered through the transmission owner's transmission revenue requirements under MISO's OATT. These types of funding mechanisms provide:

- Transmission owners with a recovery mechanism that precedes the commitment of new generating resources to interconnect to the transmission grid.
- Assurance that those generating resources that require future transmission capacity will bear a portion of the costs.

In addition to the funding mechanisms described above, several RTO OATTs, including, for example, the ISO New England (ISO-NE) OATT, include mechanisms for cost recovery associated with transmission facilities constructed within the RTO region by owners that are merchant transmission in nature. For example, the ISO-NE OATT includes separate provisions to address the reservation of service or auctioning of rights over the merchant transmission facilities and how costs will be recovered from the customers reserving such service. Until recently, FERC has required that owners of merchant transmission facilities auction all of the capacity associated with these facilities to third parties. However, in recent FERC Orders ER09-432 and ER09-433,[86] based on certain criteria, FERC permitted the merchant transmission owner to pre-subscribe a portion of the transmission capacity (e.g., 50 percent) associated with its transmission facilities before auctioning the remainder to third parties. This order provides incentives for merchant transmission developers to undertake transmission projects as it provides a mechanism for the developer to retain transmission rights without being required to auction all rights to third parties. The merchant transmission owner that receives transmission rights would not be permitted OATT cost recovery for the portion of its transmission facilities for which it receives transmission rights.

7.3 Cost Recovery Methodologies

There are numerous methods for transmission cost recovery, but the jury is still out on which method is the all-around preferred methodology. The following partial list provides a summary of transmission cost allocation methodologies taken from an Xcel Energy presentation.[87]

[86] http://www.ferc.gov/news/news-releases/2009/2009-1/02-19-09-E-15.asp
And
http://www.transcanada.com/company/zephyr_chinook.html

[87] "General Overview of Transmission Cost Allocation Methodologies", Xcel Energy, October 29, 2008

1. Postage Stamp Method: Revenue requirements associated with specific investment are divided on a pro rata demand. Postage stamp allocation can be applied on a zonal or system-wide basis. It can also be applied to only a share of the total costs, with the remainder recovered through other methods. For instance, a combined postage stamp and zonal allocation, will put a portion of the costs under postage stamp over a system-wide footprint, and a portion to be recovered from defined zones.
2. Participant Funding: The full investment costs are allocated to the generator or the entity causing the transmission project to be constructed. As expected, this puts an onerous burden on independent generators, since most would be incapable of absorbing such costs. As with other rates, the participant funding can also be applied to only a share of the total costs, with the remainder recovered through other methods
3. Beneficiary Pays: Costs are recovered from those customers (retail and wholesale) who are shown to benefit from the project. Issues arise when beneficiaries cannot be clearly defined or as the use of facilities shift in time.
4. Open Season (Market-Based): Costs are assigned to successful bidders among prospective transmission customers through an "open season" process. Successful bidders pay their pro rata capacity share of the cost of the line. Allocating all of the cost of a merchant line with high capital costs in this manner would result in high transmission rates for the merchant segment in the transmission grid and contributes to rate pancaking.
5. CAISO-Type Financing: The costs of unsubscribed capacity for eligible transmission projects is initially rolled into the transmission revenue requirement of the sponsoring transmission owner and collected through the CAISO transmission access charge. As the rest of the line is subscribed to, the access charges are adjusted.
6. Toll Road Concept: Charges for use of facilities are assessed on usage determined from actual flows and simulation models that calculate the share of flows of each transmission user on the line. Due to uncertainty involved, the methodology requires a backstop funding mechanism to ensure a reasonable level of cost recovery for the project investors.
7. Highway-Byway Zone: Cost recovery depends on designation of facilities into highway and zone categories. Zone facilities perform a load serving function and integrate local generation and local load. Highway facilities enable longer distance power transfers between zones and markets and sharing of reserves. Costs of zone facilities are paid by the zones, typically through a load ratio share. Zones also pay for the use of highway facilities based on the amount of power they import or export. The more balanced a zone in terms of its load and resources, the less it has to pay for the use of highway facilities.
8. Balanced Portfolio: This method is based on calculated benefit to cost ratio estimated for each project. The less beneficial projects (those with a benefit to cost ratio of 1 to 1 or less) are combined with the higher beneficial projects into a

portfolio, and the method would seek to "balance" the project costs across the system (or across the RTO in the case of the SPP, which has adopted this FERC-approved approach). Under this method, the less beneficial projects get built, thus helping the low benefit to cost ratio areas. In a simpler postage stamp methodology, the lower benefit to cost ratio areas would have forgone building of less beneficial transmission, and instead would have paid a larger share of the costs of the higher-rated projects. However, what the right balance is, or what the trade-offs are, between building a balanced portfolio group of transmission projects and the unequal share of high and low benefit to cost ratio areas in cost recovery, are still being argued.

Most RTOs have a postage stamp cost allocation methodology for all or portions of the transmission costs. Some apply different methodologies or a combination thereof to reliability-based transmission and to economic-based transmission.

7.4 Transmission Ratemaking Process

Providing transmission service is a capital intensive undertaking. Transmission operation and maintenance expenses are a small fraction of the total costs that are incurred in the development, construction, and ongoing operation of a transmission system. As a result, the FERC regulatory rate setting process is focused primarily on factors related to such items as rate base, the rate of return on rate base, including the ROE and capital structure, and depreciation expense.

The general process used in setting rates for transmission-related projects is as follows:

- In many RTO regions, including MISO for example, the respective RTO OATT includes a template that is used by each transmission owner to compute and update its transmission revenue requirement annually.
- This template is submitted to the RTO annually and the transmission costs of all transmission owners within the RTO are recovered in the coming year from the RTO's OATT transmission customers.
- Revenue collected from the RTO's transmission customers is distributed to the RTO transmission owners.

FERC's process for determination of revenue requirement:

- FERC reviews the investment that the transmission owner makes and determines whether the transmission owner made a "prudent" investment and can therefore include it in the rate base to earn a reasonable return on that investment.
- Depending on regulatory treatment, a determination is made concerning if CWIP costs can be included in rate base, and if so, how much. Similarly, a determination is also made on allowance for funds used during construction.
- The transmission owner proposes a method of rate recovery for depreciation expenses that regulators review, and through rate proceedings, FERC orders the

transmission owner to comply with its findings in subsequent compliance rate filings.

- The transmission owner proposes a "Capital Structure" and a ROE that FERC reviews, and through rate proceedings, orders the transmission owner to comply with its findings in subsequent compliance rate filings.
- Rate base is calculated by subtracting accumulated depreciation from the original cost of transmission investments, subject to certain adjustments.
- A "Return on Rate Base" is determined by taking into account the allowed ROE, the transmission owner's cost of debt, and the approved capital structure.
- Operating expenses include but are not limited to operation and maintenance, administration, and general costs.
- Other items included for cost recovery are income and other taxes.
- The annual "Revenue Requirement" is determined by summing the return on rate base, operating expenses, depreciation expenses, and income and other taxes.

The transmission revenue requirement approved by FERC may differ from the implied transmission revenue requirement that is in the bundled retail rates that are approved by the state's PUC. The derivation of the rates under each jurisdiction may differ in the test year used, the ROE, allocation and functionalization factors, incentives, etc.

7.5 State Rate Treatment

The three ways through which prudent transmission cost can be apportioned to customers were described in a report for RMATS.[88] A brief description of each taken from the RMATS report is provided here:

Cost Recovery through Bundled Retail Cost of Service

In the bundled cost of service, all costs, including transmission cost of service and wholesale wheeling revenues, and generation and distribution costs are bundled to form a single retail rate. No distinction is made between wholesale transmission cost of service and retail transmission cost of service. This is how PacifiCorp recovers its transmission costs in Utah, Idaho, and Wyoming and this is also how transmission cost is recovered in Colorado.

For example, PacifiCorp reports to states its financial results and operations using FERC's uniform system of accounts. All transmission net plant investment, expenses, and wholesale wheeling revenues are included in PacifiCorp's results of operations and are apportioned among the state jurisdictions it serves. A utility's purchase of transmission service from another owner's facilities is included as a wheeling expense in its cost-of-service.

[88] Wilson, Becy. "Rocky Mountain Area Transmission Study, "States Transmission Cost Recovery Process.
http://www.westgov.org/wieb/electric/Transmission%20RP/papers/UTtcr.pdf

Costs in the transmission-related FERC accounts (gross plant, accumulated depreciation, wholesale wheeling revenues, and operation, maintenance, and depreciation expenses) are generally allocated among states served by PacifiCorp based on relative loads: 75 percent weight is given to relative demand based on the sum of 12 monthly coincident peaks and 25 percent weight is given to relative annual energy use. All states in the PacifiCorp service territory allocate new net plant investment and annual operation and maintenance expenses and firm wholesale wheeling revenues using the 75 percent demand, 25 percent energy allocation factors. Non-firm wholesale wheeling revenues are allocated based on relative annual energy use. In Colorado, transmission investment and operations and maintenance costs are spread over the 12 monthly coincident peak demand.

A few of the states PacifiCorp serves directly assign pre-1989 net plant investment to the pre-merger division (Pacific Power or Utah Power) in which the plant is located and then allocate the cost to the states in the division using redefined allocation factors (based on relative loads in the division rather than the total system) similar to those noted above. Most states, including Utah, Oregon, and Wyoming, allocate new and old net plant investments system-wide without prior direct assignment of pre-1989 net plant investment to a division. All PacifiCorp states allocate new net plant investments system-wide based on relative use.

Under this approach, retail customers bear the risk of any difference in wholesale transmission cost-of-service and firm wholesale wheeling revenue.

7.6 Cost Recovery through Unbundled Transmission Service

Unbundled transmission service separates the transmission service cost from non-transmission service cost. A fully-distributed transmission service cost analysis is performed and these costs (including only non-firm wholesale wheeling revenues as credits) are used to derive a firm transmission rate based on total use (retail plus wholesale) of the transmission system. This approach is the basis for FERC wholesale wheeling tariffs (OATTs) and a similar approach is also used in Utah and Idaho for retail recovery of natural gas pipeline cost. Wyoming also uses an analogous procedure to establish retail intrastate gas and oil pipeline rates.

Under this approach, retail customers still bear the risk of any difference in wholesale transmission cost-of-service and firm wholesale wheeling revenue.

Unbundled retail and wholesale rates also separate the transmission service cost from the non-transmission service cost. A fully-distributed transmission service cost analysis is again performed but now these costs (including only non-firm wholesale wheeling revenues as credits) are allocated to firm retail and wholesale customers based on relative use. Thus, transmission service is further unbundled into retail transmission service and wholesale transmission service. A separate firm retail transmission rate is computed from the retail transmission distributed cost-of-service study. The retail rate is then multiplied by firm retail use to derive the transmission expense and is included in the retail cost-of-service. No information has been found to indicate that any state in the RMATS footprint uses this approach.

Under this approach, retail customers no longer bear the risk of any difference between wholesale transmission cost-of-service and firm wholesale wheeling revenue. This spreading of risk is an important distinction from the previous two approaches because it may be more compatible with non-utility based transmission expansion investment decisions and alternative transmission expansion funding alternatives, i.e., direct assignment or participant funding.

7.7 Regional Transmission Rates

The most pressing transmission rate issue on a regional level is the pancaking of rates in a non-RTO and non-ISO market, which includes most of the WECC markets including RMPA and Colorado. Pancaked transmission rates are analogous to multiple toll booths along a highway. A transmission customer has to pay multiple charges if the wheeled power traverses multiple transmission service territories. Elimination of pancaked rates in a multi-jurisdictional market with multiple independent transmission providers, each with separate transmission rates, is not a simple task.

To understand the various alternatives, the following section provides a short summary of various types of rates based on descriptions provided by Brown and Sedano.[89] The four industry accepted methods for setting transmission rates on either a state or regional level include:

7.7.1 Pancaked Rates

Pancake rates come into play when power under contract traverses more than one power system and each system charges its full rate to provide transmission service. This method of pricing for a regional transmission system is expensive and tends to discourage companies from sending power over long distances and through several transmission systems, regardless of the value of the transaction to consumers.

7.7.2 Postage Stamp Pricing

Under postage stamp pricing it would cost the same amount to wheel power from within a region to another point in that region irrespective of distance, even if the defined region contains multiple states. This is similar to having a single postage stamp rate for standard mail service. There are no zones that require people to compute different prices at each zone. To some degree, this pricing scheme means that the local delivery service that probably costs less than the postage stamp rate is subsidizing the long-distance letter service that probably costs more than the postage stamp rate.

[89] "Electricity Transmission: A Primer", Matthew Brown and Richard Sedano, February 2005

The per-unit fee to use the transmission system within a single zone is the same, whether the power is contracted to move a short distance or a long distance. Companies located in less densely populated areas and in higher cost areas tend to favor postage stamp pricing over an alternative known as license plate pricing.

7.7.3 License Plate Pricing

Some parts of the transmission system -- such as the system in much of North Dakota and South Dakota -- are expensive to service because they have low populations and long distance transmission lines. Other parts of the system -- such as NStar, which serves the Boston area -- have much less extensive transmission systems that cover only short distances and serve dense populations; therefore, their costs are lower. Older systems that have had time to gradually pay for the transmission facilities also tend to be less expensive than the new transmission systems that are still in the process of recovering their costs.

License plate pricing means that customers that use the transmission grid pay different prices based on the costs at the point at which the power is delivered to their area. The license plate metaphor applies because each company pays a fee to obtain access to the transmission system and can use any part of the system after paying that fee. In comparison, a car or truck owner who pays a license fee in Colorado can use the roads anywhere in the country. The companies based in the low-cost areas tend to favor this approach.

7.7.4 Distance-Sensitive Pricing

Distance-sensitive pricing bases the price for using the transmission system on the number of miles of the system that transmission customers contract for. Users that contract to use the transmission system for 10 miles would pay less than those that use it for 100 miles. Distance-sensitive rates may discourage unwise investments in long-distance transmission. As a result, distance-sensitive pricing may, in some markets, be a barrier to fully free-flowing wholesale power competition.

7.7.5 Discussion

Postage stamp rates allow all customers throughout the region to pay a single rate based on the full cost of the entire region-wide transmission system. License plate rates allow all customers within a specific zone to pay only the cost of the transmission system within the zone. Under both approaches, the transmission customer has access to the transmission system of the entire RTO and there is no pancaking of transmission rates. Even under the license plate approach, there is no pancaking of rates regardless of the number of transmission systems that are actually used for delivery of electricity; the transmission customer will only pay their zonal (license plate) rate. Consequently, the elimination of pancaked rates may actually be detrimental to transmission owners that have a significant amount of third party wheeling as they would no longer be able to recover those revenues.

Additionally, there is probably no single rate design methodology that would be acceptable to all transmission owners within an RTO/ISO regime. Since loads pay the transmission charges, postage stamp rates may be more favorable to customers within a zone whose costs are higher on a zonal basis (i.e., based on license plate rate). Of course, the opposite is also true -- customers with low license plate rates would not benefit from the migration over to a postage stamp rate approach.

7.7.6 Examples of Transmission Rates in Various ISOs

ISO-NE's costs of existing and pooled facilities are socialized to all transmission customers through the use of postage stamp rates. The Electric Reliability Council of Texas also has postage stamp rates.

Several RTOs have blended rates for new and existing facilities. For example, SPP and MISO have postage stamp rates only for new high voltage facilities and license plate rates for existing facilities.

The CAISO has postage stamp rates that are voltage-delineated for both existing and new facilities. PJM currently has license plate rates.

7.8 Financing Transmission

The Western Interconnection is a composite of the transmission systems owned by IOUs, Munis and power district utilities, generation and transmission cooperatives and associations, two federal power marketing administrations, and merchant transmission companies. Each of these has its own tailored structure for financing and cost recovery.

7.8.1 Investor-Owned Utilities

IOUs are typically state-regulated natural monopolies with exclusive franchise rights in their territories. Such companies are focused on meeting the needs of their own native and captive customers, for whom they plan and develop their system. They are motivated by state level regulatory review to provide reliable and the least cost power to their customers. Their proposed capital projects are subject to review by regulators to ensure that they are appropriately sized to their customers' needs and that the project costs are prudent.

In more recent years, in either responding to requirements of joining an RTO or ISO, or as mandated by a state legislator, some of the IOUs have either divested their generation or transmission systems, or created financially and administratively separate affiliates.

For traditional IOUs, financing for either generation or transmission has been based on a traditional business model relied upon for the overall borrowing power of the entire utility. The traditional utility rate making process assumes attracting capital from traditional sources in the financial community of capital at reasonable costs. The financial community views investment in IOU-type transmission as a low risk proposition and ideal for long-term borrowing due to their being viewed as assets with long service life, and with high up-front capital costs, where fixed costs are recovered with a high degree of certainty over the long term as allowed by the state-level regulator.

Therefore, in the traditional investment process, transmission financing, cost recovery, and regulatory rate making have been looked at as an integral process and key to the borrowing capabilities of the utilities.

To allow new construction or expansion of existing facilities and formulate the cost recovery and inclusion in rates of the costs of such activities, state regulators review transmission expansion proposals by IOUs for prudency, i.e., to ensure that they are needed and appropriately sized for their customers, and that the proposed costs are reasonable. Long-term benefits are matched against the cost of long-term assets and that cost, if found prudent, is recovered over the life of the assets in the rates under that state's jurisdiction.

7.8.2 Municipal and Public Utility Districts

At a smaller scale are the municipal and public utility districts, which operate local distribution companies to the benefit of the residents in their service territories. They may, individually or through "joint action agencies," own generation and transmission or purchase generation and transmission services from other entities. On most matters, these utilities are regulated more by their town or county or member-appointed governing boards subject to a public process, than by state level.

Munis have generally financed transmission and generation facilities with tax-exempt debt that places restrictions on the use of those facilities. Their cost recovery processes are also through public rate making hearings to set cost-based rates for their customers.

7.8.3 Cooperative Generation and Transmission Associations

Other forms of jointly-owned entities are the cooperative generation and transmission associations, which are formed jointly by smaller rural members or Munis. The cooperative associations operate mostly at the wholesale level and their ultimate customers are their memberships. They are regulated by the governing boards formed by their membership. In Colorado, Tri-State must receive a CPCN from the CPUC before it can build high voltage transmission lines.

Cooperatives have generally financed transmission and generation facilities with debt from the Rural Utilities Service, which also imposes restrictions on the use of those facilities by other entities.

7.8.4 Federal Power Marketing Administrations

At the federal level, there are federal power marketing administrations, such as Bonneville Power Administration and WAPA, which are entities formed to market the electricity generated by the federally owned projects, which are almost exclusively hydro power plants. The power is primarily marketed at the wholesale level to Munis and Co-ops over their own transmission systems or through contracts with other entities. These entities are not subject to regulatory oversight regarding their rates and capital projects. They depend on executive and congressional bodies and the public process for oversight and guidance.

Bonneville Power Administration's borrowing authority for capital projects is established and must be expanded by Congress. While WAPA does not have borrowing authority and must acquire appropriations from Congress for any capital improvements, alternative financing mechanisms are being explored. Both entities' cost recovery processes are through public rate making hearings to set cost-based rates for their customers. The American Recovery and Reinvestment Act, signed into law on February 17, 2009, provides WAPA with $3.25 billion in borrowing authority.

7.8.5 Merchant Transmission

Merchant transmission companies are entrepreneurial in nature, operate in niche value markets, and earn a return on their investment based on the value they provide in the open market, instead of a earning a cost-based return in a regulated market. Instead they earn money from contracts they sign with companies that ship power over their transmission lines. American Transmission Company and Trans-Elect Development Company are examples of merchant transmission companies.

Due to their risk-taking nature, merchant transmission companies are more inclined to see opportunities in congested areas or regions lacking in transmission capacity, and by investing in new transmission to relieve congestion or provide access to new generation, partake in a share of savings and benefits they create. As such they are more exposed to the uncertainties of the market and the success or failure of their ventures, and do not have the same level of assurance of cost recovery as a regulated utility, and therefore, may have a more difficult time to raise the necessary capital in equity and credit markets. RTO- and ISO-type markets are ideal arenas for merchant transmission, since they are participants in a market with a level-playing field with uniform rules and policies and transparent prices. However, merchant transmission companies still face extraordinary hurdles in regulated and protected markets.

Although merchant transmission owners can obtain market-based rates either through open season auctions or bilateral negotiations, they have to file their market-based rates with FERC for approval. As expected, since they do not have native retail customers, their rates are typically higher than load serving transmission companies, particularly those with long-paid assets.

8.1 Outline of the Current Colorado Public Utilities Commission Process

8.1.1 Overview

The CPUC,[90] created in 1913, is one of the agencies under the Colorado Department of Regulatory Agencies.[91] Its mission is "to achieve a flexible regulatory environment that provides safe, reliable, and quality services to utility customers on just and reasonable terms, while managing the transition to effective competition where appropriate." The PUC has full economic and quality of service regulatory authority over investor-owned electric, gas, and water utilities, as well as partial regulatory control over Munis and electric associations.

The regulation of the so-called "fixed utilities" -- electric, gas, water, and telecommunications companies -- has seen some ebb and flow over the decades. Colorado's Co-ops went to the legislature to seek PUC regulation in 1961 and then sought an end to that regulation in 1983. They were successful both times. The 1983 deregulation procedure required a vote of each Co-op's membership, and most of the state's Co-ops have voted to become deregulated. The 1983 legislation also ended the Commission's jurisdiction over Munis, whereas the PUC previously regulated their services when provided to customers outside of city limits.

The PUC is funded with fees paid by the regulated companies, not by general tax revenue. Two-thirds of the funding comes from fees paid by gas, electric, telephone, and water utilities. The other one-third comes from registration and permit fees charged to motor carriers, allowing them to operate in Colorado. For fiscal year 2007-08, the actual revenue was $19,605,460, while expenditures amounted to $18,873,280.

8.1.2 Public Utilities Commission Organization

The PUC is composed of three members who are appointed by the governor and confirmed by the senate for a term of four years. They are limited to two terms. A director manages the staff and daily operations of the PUC. As of this writing, the PUC is authorized to have 95.6 full-time equivalent employees. These staff members have specialized knowledge in engineering, economics, law, finance, support or

[90] http://www.dora.state.co.us/puc/

[91] http://www.dora.state.co.us/

management. The PUC is comprised of a number of working sections and units. The two sections most directly dealing with electricity-related issues are energy and economics.

The objective of the energy section is to assure the availability of safe, reliable, adequate, and efficient electric, gas, and steam services to utility customers at rates that are just, reasonable, and not discriminatory. This section conducts financial and engineering analyses, audits, and investigations for the PUC.

The economics section serves the PUC through its analysis of telecommunications, energy, water, and steam utilities regulated by the PUC with the objective of aiding the PUC.

The electricity section is described in more detail later in this report.

8.1.3 Generic Colorado Public Utilities Commission Process Description

Oversight by the Public Utilities Commission

The actions of the PUC affect the lives of virtually every Colorado citizen in one way or another. Each year the PUC oversees utilities generating billions of dollars in annual jurisdictional utility revenues in Colorado.

Article XXV of the Colorado Constitution mandates that the regulation of public utilities is the province of the General Assembly and that unless that body should otherwise designate, the PUC is mandated with the authority provided in this regulation. Title 40, Colorado Revised Statutes, provides legislative policy direction to the PUC as to how utility regulation is to be conducted in Colorado. The PUC derives its authority wholly from constitutional and statutory provisions.

The statutes also mandate that the PUC must first give paramount consideration to the public interest. This requires constant attention to achieve the appropriate balance between the needs of Colorado customers for safe and reliable utility services at reasonable rates and the needs of utility service providers to earn a reasonable profit and to sustain a reliable utility infrastructure throughout Colorado.

The General Assembly requires that the PUC conduct its business in two ways:

- Quasi-Legislative: Generally, the Quasi-Legislative proceedings involve rulemaking and does not require stakeholders to be represented by an attorney in order to participate and have input into the process.
- Quasi-Judicial: The Quasi-Judicial proceedings are litigated proceedings, where the formal administrative law process is used to provide appropriate "due process" protections to affected parties. These proceedings must be conducted "on the record" where representation by an attorney is often necessary. The proceedings may be adversarial and contentious, and often involve multiple parties. The scope and complexity of issues involved in the proceeding typically determine how long the proceeding will last and the cost. Some proceedings, such as routine transportation issues, may be resolved in less than a month. Others, such as

complex rate proceedings to determine base rates for gas and electric service, may take months to resolve.

In both cases, the Colorado Sunshine Law requires that all of the business of the PUC be conducted in public, with appropriate notice to allow interested individuals to observe and participate in the proceedings. The PUC is required to comply with statutory guidelines for timely completion of proceedings.

Electricity Section of the Public Utilities Commission

The mission of the electricity section of the PUC is to achieve a regulatory environment that provides safe, reliable, and quality services to electric utility customers on just and reasonable terms. The electricity section of the PUC serves the public interest by balancing the needs of customers and utility service providers in the following areas of responsibility:

- Rates: Maintaining electricity rates as low as possible for residential and business consumers consistent with minimum standards of service, safety, economic viability, and the environment.
- Service: Providing customers with adequate, reliable, responsive, safe, and timely electric service.
- Infrastructure: Ensuring that investor-owned regulated electric providers earn a return sufficient for their long-term economic viability and their ability to update their physical plant or equipment necessary to provide electric service essential to Colorado consumers.

The electric section of the PUC accomplishes its mission by issuing authorities to operate, establishing industry rate, service, adequacy, and reliability standards, initiating enforcement and compliance activities, and assisting consumers with complaints and educational efforts.

Issuing Authorities to Operate

Each PUC-regulated electric utility serving Colorado customers must apply for and receive a CPCN to operate in Colorado. Issuing CPCNs increases public confidence in the companies authorized to provide electric services in the state. It promotes financially healthy companies who will stay in business and provide a high level of service to their customers. The PUC provides oversight over entry and exit from the Colorado market with the goal of protecting customers and assuring that companies provide service to customers on a non-discriminatory basis.

Establishing Industry Rate and Service Standards

Rates for electric services must be approved by the PUC. This section reviews requests by electric utilities for rate changes to ensure that financial, engineering, legal, and economic requirements are met. This section considers and implements alternative rate regulations, such as variable, incremental, or interruptible electric rates where consistent with the public interest.

In addition, this section assists the PUC in establishing service standards to initiate and maintain service and equipment to a level necessary to promote the safety, health, comfort, and convenience for customers of all regulated electric providers operating in Colorado. These service standards range from establishing minimum adequacy and reliability to ensuring power is available to Colorado consumers to determining customer deposit requirements.

Initiating Enforcement and Compliance Activities

This section ensures compliance with state statutes, PUC decisions, rules and safety standards, and takes enforcement action to correct non-compliance, as appropriate. A variety of tools are available to obtain compliance including desk and field audits of financial and service records, inspections of facilities and equipment, complaint investigation, show-cause actions, revocation action, and court actions intended to force compliance. Each of these tools involves due process intended to protect the rights of the regulated service provider as well as allowing input from other affected parties. Due process may include warning letters, notices of proposed action, opportunities to respond to allegations, mediation, settlement negotiations, evidentiary hearings, right to appeal decisions before the PUC, and appellate review of all final PUC decisions.

Assisting Consumers with Complaints and Education

This consumer assistance section responds to financial, economic, and engineering inquiries. These activities include responding to general inquiries from individual citizens; the General Assembly; the governor's office; other federal, state, and local government officials; industry professionals; utility service providers; attorneys; and national investment firms.

Interstate Cooperation

The PUC is authorized to confer with or hold joint hearings with the authorities of other states or any agency of the US in connection with any matter under Title 40 (CRS 40) and to enter into cooperative agreements with said entities to enforce the economic and safety laws of Colorado and the US CRS 40-2-115.

8.1.4 Senate Bill 07-100 Colorado

Senate Bill 100 (SB07-100) is a bill passed by the Colorado legislature and signed by the governor in 2007.[92] SB07-100 made the following determinations:

- A robust electric transmission system is critical to ensuring the reliability of electric power for Colorado citizens.

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http://www.leg.state.co.us/clics/clics2007a/csl.nsf/fsbillcont3/4B1B8C4BA39953A287257251007D6838?open&file=100_enr.pdf

- Colorado's vibrant economy and high quality of life depend on the continued availability of clean, affordable, and reliable electricity.
- Therefore, Colorado utilities should continually evaluate the adequacy of electric transmission facilities throughout the state and should be encouraged to promptly and efficiently improve such infrastructure as required to meet the state's existing and future energy needs.

The bill required that Colorado's two investor-owned utilities file a biennial plan on October 31. The biennial plan is required to cover the following actions by the filing utility:

- Designate the energy resource zones.
- Develop plans for the construction or expansion of transmission facilities necessary to deliver power consistent with the timing of energy resources located in or near such zones.
- Consider how transmission can be provided to encourage local ownership of renewable energy facilities.
- Submit proposed plans and applications for CPCNs to the PUC for review.

The bill also stipulates that a public utility shall be entitled to recover, through a separate rate adjustment clause, the costs that it prudently incurs in planning, developing, and completing the construction or expansion of transmission facilities for which the utility has been granted a CPCN or for which the PUC has determined that no CPCN is required. The transmission rate adjustment clause is subject to annual changes January 1st of each year.

The two IOUs in Colorado are PSCo and Black Hills Energy. Based on the Black Hills Energy SB-100 study timeline presented in their April 22, 2009 stakeholder meeting, Black Hills Energy will develop its CPCNs in the August-October 2009 time period.[93] Based on the PSCo report of November 24, 2008,[94] PSCo expects to go forward with one or more CPCN applications as early as Spring of 2009. They filed an application in May 2009 to build a double circuit 230-kV line from the San Luis Valley to a new Calumet Substation, near Walsenburg, Colorado.

8.1.5 Current Public Utilities Commission Jurisdiction

The PUC has financial and quality of service regulatory authority over two IOUs and one electric cooperative association. The PUC has partial regulatory authority over municipal electric utilities, and 22 electric cooperative associations.

In 1983, the Colorado legislature created a process by which Co-ops could be exempted from public utilities law by a vote of their members. Since then, all of the cooperatives in Colorado, except one, have removed themselves from PUC regulation.

[93] http://www.blackhillscorp.com/trasmission/Stakeholder_Meeting_Presentation_42209.pdf

[94] http://www.dora.state.co.us/puc/docketsdecisions/DocketFilings/08M-521E/08M-521E_SB07-100_PSCo11-24-08InformationalReport.pdf

These electric associations are governed by their own board of directors and are outside of PUC authority for most issues. The PUC does retain safety jurisdiction and limited jurisdiction over consumer complaints.

Wheatland Electric Cooperative, Inc., a Kansas-based cooperative that serves some customers in southeast Colorado, is the only member-owned electric cooperative still under the jurisdiction of the PUC.

Therefore, the PUC-regulated electric related entities are PSCo, Black Hills Energy, and Wheatland Electric Cooperative, Inc.

Aside from CPCNs, the PUC does not regulate Tri-State, except for requiring that Tri-State submit a plan to the PUC every four years on how it will meet projected future demand. This, however, may change in the future. PUC has opened an investigation seeking comment on whether it should change its oversight of Tri-State's resource planning process.[95]

The PUC requested that written comments be submitted by March 16, 2009. After considering the comments of interested parties and after further deliberations, the PUC will determine whether to proceed with formal changes to its rules.

The PUC chairman has proposed several potential regulatory approaches, ranging from the hands-off approach of the status quo, to full regulation of resource planning similar to that applied to the state's IOUs, PSCo, and Black Hills Energy.

8.1.6 Approval Process in Colorado: Certificate of Public Convenience and Necessity and Local

Siting Process

The transmission siting process is a complex multi-stage effort because of the geographic reach of transmission projects and its impact on environment, land use, wildlife, and local and regional economies. After a decision is made regarding the need for new transmission lines, then a number of steps need to be taken. Figure 8-1 illustrates the many facets of the siting process.

[95] http://www.dora.state.co.us/puc/publications/NewsReleases/01-29-09NR_Tri-StateERPcomments.pdf

Figure 8-1. Transmission Siting Process

Source: Tri-State, "San Luis Valley Electric System Improvement Project" http://www.tristategt.org/Transmission/sanluisvalley/documents/NEPA-Siting-and-permitting-process-2.pdf

The following exposition encapsulates the various steps that need to be taken in the siting process, based on the example that Tri-State has listed, in order to establish a route and meet regulatory requirements for its double-circuit 230-kilovolt transmission line between the Walsenburg Substation and the San Luis Valley Substation in south central Colorado.[96]

[96] http://www.tristategt.org/Transmission/sanluisvalley/documents/NEPA-Siting-and-permitting-process-2.pdf

Siting Goals

The goal of the siting process is to: (1) Maximize the use of opportunity areas; and (2) Minimize the use of constraint areas.

Preliminary Corridor Identification Phase

Step 1. Define the project study area by its beginning and end points.

Step 2. Conduct an opportunity and constraint analysis using mapped resource data of land use, environmental and engineering factors.

> Primary opportunities: Existing utility line easements; Transportation corridors; Rangeland; Edges of fields
>
> Primary constraints: Residential areas; Open waterbodies; Irrigated agriculture; Conservation areas; Critical plant or wildlife habitats

Step 3. Identify preliminary alternative corridors from the analysis above.

Step 4. Seek public input and feedback on the preliminary alternative corridors to balance the need for reliable electric service with potential environmental impacts, public acceptance, engineering, economics and legal and regulatory requirements.

Route Refinement Phase

Step 1. Address specific concerns identified by the public, such as new resource information, and ref ne the preliminary alternative corridors into alternative routes.

Step 2. Conduct a comparative analysis of the alternative routes: (i) Identify comparative criteria, and (ii) Rank the alternatives based on the criteria

Step 3. Present the comparative analysis and alternative routes at public route refinement workshops for review and comment.

Alternative Identification Phase

Step 1. Use public comments and stakeholder concerns from the route refinement workshops to make final adjustments to the alternative routes.

Step 2. Update the comparative analysis to reflect the refined routes.

Step 3. Identify a preferred route and any feasible alternatives based on the comparative analysis.

Step 4. Carry the preferred and alternative routes forward for NEPA analysis.

Public Involvement

Hold public scoping workshops to present siting process information to the public and local, state, and federal agencies.

Collect comments to use to revise and refine the alternative corridors and routes.

Prepare an Environmental Assessment under the NEPA, required by the Rural Utilities Service, which will assist with funding for Tri-State's capital construction costs.

Source: Tri-State, "San Luis Valley Electric System Improvement Project."
http://www.tristategt.org/Transmission/sanluisvalley/documents/NEPA-Siting-and-permitting-process-2.pdf

Permitting Process

The type of permit and process varies from county to county and needs to be determined on an individual basis. A utility must obtain a Certificate of Public Convenience and Necessity from the PUC in addition to any necessary county permits. A successful appeal to the PUC of local permit denials preempt local authority.

Colorado has a multi-jurisdictional transmission permitting and siting process. All transmission lines require local government permits. Lines built by IOUs and Tri-State require a CPCN. An entity may appeal a land use permit denial at the local level to the PUC, under certain circumstances.

8.2 Certificate of Public Convenience and Necessity

A utility seeking authority to provide service, i.e., authority to construct and to operate a facility or an extension of a facility, in Colorado pursuant to a franchise, shall file a CPCN application.

IOUs and generation and transmission cooperatives in Colorado may not begin new construction or extension of transmission lines or facilities until the PUC issues a CPCN for the project or notifies the utility that a CPCN is not necessary. Co-ops are subject to this requirement for transmission projects if the construction or expansion occurs outside of the cooperative's certificated service area.

The utility need not apply to the PUC for approval of construction and operation of a facility or an extension of a facility, which is in the ordinary course of business. There is currently discussion among stakeholders on the meaning of "ordinary course of business."

The CPCN application requires information regarding the facility, such as its description, estimated cost, anticipated construction start date, construction period, and in-service date, a map identifying the location, electric one-line diagrams as applicable, information on alternatives studied, costs for those alternatives, and criteria used to rank or eliminate alternatives, a report of prudent avoidance measures considered, and justification for the measures selected to be implemented.

8.2.1 Requirements for Transmission Facilities

For transmission facilities, additional requirements include a description of the utility's actions and techniques relating to cost-effective noise mitigation with respect to the planning, siting, construction, and operation of the proposed transmission construction or extension. Requirements include provision of computer studies, which show the potential noise levels.

Additional requirements for construction or extension of transmission facilities include description of the utility's actions and techniques relating to prudent avoidance with respect to planning, siting, construction, and operation of the proposed construction or extension. As defined in the rules, "prudent avoidance" means the striking of a reasonable balance between the potential health effects of exposure to magnetic fields and the cost and impacts of mitigation of such exposure, by taking steps to reduce the exposure at reasonable or modest cost.

No utility or cooperative electric association, which has voted to exempt itself pursuant to § 40-9.5-103, C.R.S., may commence new construction, or extension of transmission facilities or projects until either the Commission notifies the utility that such facilities or projects do not require a CPCN or the PUC issues a CPCN. Co-ops which have elected to exempt themselves from the Public Utilities Law pursuant to § 40-9.5-103, C.R.S., do not need a CPCN for new construction or extension of transmission facilities or projects when such construction or expansion is contained entirely within the cooperative's certified area.

Certain modifications to transmission facilities that were not part of the construction design authorized through a previous PUC determination shall be reviewed by the PUC for determination of whether a CPCN is needed for the proposed modification or whether the proposed modification is in the ordinary course of business. CPCN rules provide a list of such modifications. All other modifications to existing transmission facilities not on the list do not require a CPCN and are deemed to be in the ordinary course of business.

8.2.2 Timeline

The CPCN process includes a number of steps that need to be completed during a specified timeline on an annual basis:

- By April 30, any utility or cooperative electric association, which has voted to exempt themselves pursuant to § 40-9.5-103, C.R.S., are required to submit to the PUC a filing for a determination of which of the utility's proposed new construction or extension of transmission facilities for the next three calendar years, commencing with the year following the filing, are necessary in the ordinary course of business and which require a CPCN prior to construction.
- By May 15, the PUC gives notice of each filing made pursuant to this rule to all those who it believes may be interested. Any interested person may file comments regarding the projects.
- The rules require the PUC staff to make a recommendation to the PUC as to whether each proposed project is in the normal course of business and does not require a CPCN, or whether a CPCN is required for the project. The staff reviews the filing and any comments received and makes recommendations according to the following schedule:
  - For any new construction or extension, which is scheduled to begin in the calendar year of the filing or in the next calendar year, the staff shall make its recommendations by May 31 of the year in which the filing is made.
  - For any new construction or extension that is scheduled to begin in the second or third calendar year following the year in which the filing is made, the staff shall make its recommendations by August 31 of the year in which the filing is made.

- The PUC then issues its decision in accordance with the following schedule:
  - For any new construction or extension of transmission facilities or projects, which is scheduled to begin in the calendar year of the filing or in the next calendar year, the decision designating each transmission facility that requires a CPCN will be issued by June 30 of the year in which the filing is made.
  - For any new construction or extension of transmission facilities that is scheduled to begin in the second or third calendar year following the year in which the filing is made, the decision designating each transmission facility that requires a CPCN will be issued by October 31 of the year in which the filing is made.
- The utility is then required to install and maintain service connections from transmission extensions consistent with conditions contained in the utility's tariff.
- In addition to the list of new construction or extension of transmission facilities, each utility is required to provide by April 30 of each year a list of projects built during the past calendar year. These projects, considered as being done in the normal course of business, include the following:
  - New and/or replacement transformers, breakers, or capacitor banks with larger transformers, breakers, or capacitor banks.
  - The raising and/or strategic placement of transmission structures in order to raise the conductor, thereby increasing clearance, permitting more current flow and increasing the megavolt ampere rating.
  - The declaration of a higher rating for a line after an engineering and physical inspection such that existing line clearances are sufficient to allow more current flow, thereby increasing the megavolt ampere rating.

8.2.3 Local Governments Siting Approval

Colorado state law provides broad authority to local governments to plan for and regulate the use of land within their respective jurisdictions. Colorado law requires final local government action on any application of a public utility or a power authority providing electric or natural gas service that relates to the location, construction, or improvement of major electrical or natural gas facilities within 120 days after the utility's or authority's submission of a preliminary application (if a preliminary application is required by the local government's land use regulations) or within 90 days after submission of a final application.

If the local government does not take final action within such time, the application shall be deemed approved. Within 28 days of the submission by a utility or authority of an application, the local government must notify the utility or authority of any additional information that must be supplied by the utility or authority to complete the application. The notice shall specify the particular provisions of the local government's land use regulations that necessitate submission of the required information. The 120- or 90-day period, as applicable, during which the local government is to take action on an application, commences on the date that the utility or authority provides the requested additional information to the local government in response to the notice.

A "major electrical or natural gas facility" includes electrical generating facilities; substations used for switching, regulating, transforming, or otherwise modifying the characteristics of electricity; transmission lines operated at a nominal voltage of 69,000 volts or above; structures and equipment associated with such electrical generating facilities, substations, or transmission lines; or structures and equipment utilized for the local distribution of natural gas service including, but not limited to, compressors, gas mains, and gas laterals.

8.2.4 Appeal of Local Government's Land Use Decisions

In 2000, the Colorado General Assembly passed legislation allowing utilities (including power authorities) to appeal city or county land use decisions concerning major electrical facilities to the PUC. If a local government denies a permit or application of a public utility or power authority that relates to the location, construction or improvement of major electrical or natural gas facilities, or if the local government imposes requirements or conditions on such permit or application that will unreasonably impair the ability of the public utility or power authority to provide safe, reliable, and economical service to the public, the public utility or power authority may appeal the local government action to the PUC as long as certain conditions are met.

To file an appeal of a local land use decision to the PUC, the utility must obtain a CPCN from the PUC, show that no CPCN is required, or show that the PUC previously issued a decision, which conflicts with the local land use action. In addition, the utility or power authority must show that it notified the local government of its plans to site a major electrical facility within its jurisdiction prior to submitting the preliminary or final permit application, but not later than complying with the PUC process for obtaining a CPCN for the facility.

Utilities and power authorities must have consulted with the affected local governments by identifying the routes or locations of the facility and must have attempted to resolve land use issues arising from the application. Finally, the utility or power authority must have considered and presented reasonable siting or design alternatives to the local government or must explain why no reasonable alternatives are available. If these preconditions and notification and consultation requirements are met, the utility may make a filing appealing the local land use decision. In making its decision concerning the appeal, the PUC balances the determinations made by local governments that are exercising reasonable constitutional policing and licensing powers with respect to local land use concerns with the broader statewide interest in the locations, construction, and improvement of major electrical and natural gas facilities.

After obtaining final land use permits, utilities negotiate the value of easements for the right-of-way with each property owner.

8.2.5 Summary of General Siting Process

For public utilities or power authorities, the siting process includes the following steps:

- First, the utility must apply for a CPCN from the PUC.
- Prior to this, and no later than, the filing of the CPCN application, the utility must notify the affected local government(s) of its transmission plans.
- Once the local governments have been informed, the utility must then obtain applicable permits from each affected local government.
- This may occur simultaneously with the proceedings for the CPCN. The CPCN may be issued without possession of all the local permits.
- Once the CPCN application is filed with the PUC, the PUC has 60 days to issue the CPCN, deny it, or request additional information.
- The decision of the PUC may be appealed to a District Court. However, only issues of law will be reviewed.
- The local government has 28 days to respond to an applicant with a request for more information if such a request is necessary.
- Local governments are required to respond with a decision within 120 days of the filing of a preliminary application (when required) or within 90 days of filing of an application.
- Lack of response on the part of the local authority will be deemed approval.
- Decisions of the local government may be appealed to the PUC if the utility has either filed for, or obtained, a CPCN; a CPCN is not required; or the PUC has previously entered an order.
- Thus, the CPCN filing is a prerequisite to any appeal of a local government decision.

8.3 Implications for Moving Power from Generation Development Areas

8.3.1 Current Regulatory Process and Rate Pancaking

Pancaked pricing is one of the more complex issues where a clear-cut solution acceptable to all stakeholders may not exist. As described earlier, RTO and ISO markets have simplified system-wide transmission rates that facilitate system-wide wheeling of power with a single toll price, either in the form of a postage stamp rate or a license plate rate. Even in such systems, there are potential losers and winners, since some transmission providers are getting less than their perceived revenue needs, while other providers are getting more than their perceived revenue needs.

The pancaked transmission rates in Colorado are a reflection of the absence of an RTO- and ISO-type market in the region, and also of the diversity of the transmission provider types and their regulatory jurisdictions. Modifying the transmission rates at the state level would require FERC's involvement. In the absence of an RTO- and ISO-type authority, a transmission provider would still need to file an OATT with FERC and obtain its approval. The non-jurisdictional utilities would file an OATT under the FERC reciprocity rule. Therefore, the power of the PUC in developing and/or imposing a simplified wholesale transmission rate is limited.

However, one option that the PUC may have is in allowing new merchant transmission costs to be partly recovered by a statewide retail basis, although that option may also be limited to IOUs or merchant transmission. Any cost roll-up and recovery through retail rate "adders" or "surcharges" may be viewed as discriminatory if it applies only to IOU native load.

Another option, in the absence of having a full-force RTO, is the creation of an independent transmission company, which is operationally independent from the market participants, but still owned by them. An independent transmission company would be an independent for-profit company engaged in the business of transmission with responsibility for transmission development and operations independently from its owners, with wholesale transmission rates that apply across its territory. One difficulty with this approach is the underlying balkanization of the market within Colorado, and the daunting task of compelling or motivating various utilities to divest their transmission companies into an independent company.

8.3.2 Need for Facilities Built Primarily for Export of Power

Identifying and determining the need for facilities that are built primarily for export of power requires a regional economic analysis-based transmission planning that would evaluate the export potential of native generation and the appropriate sizing (or "right sizing" in WGA terminology[97]) of transmission needed for power exports. The footprint of the analysis needs to be regional in extent, ideally covering the Rocky Mountains, desert southwest, and California areas. The underlying assumptions would include generation costs (or bids) by various generation types and by location. The regional dispatch will be subject to transmission constraints. Study of various scenarios would determine the appropriate sizing or right sizing of transmission facilities needed to accommodate export of power from Colorado to the other regions. Of course, there is always a chance that the underlying economics may drive the analysis results to a "no-need" solution.

After determination of the need for export facility, a state authority will then designate the facility, based on the results of the aforementioned analysis, as a primary or beneficial facility, which based on such designation, would be eligible for any applicable preferential treatment in terms of financial incentives and cost recovery schemes.

[97] http://www.westgov.org/wga/testim/transmission5-1-09.pdf

8.3.3 Right Sizing of Lines Beyond Identified Need

Identification and determination of the need for additional transmission capacity beyond what is required to serve native load, will require a process similar to the one described above for export facility. In fact, the two, i.e., the export facility and excess capacity analysis could be one and the same.

A detailed economic-based transmission planning exercise would identify and determine the economically justifiable excess transmission capacity based on projection of future export load, internal native loads, and the potential generation resources. It is quite possible that the economic analysis may identify no need for excess capacity. However, a non-zero excess capacity would be determined, if the projected future generation resources can economically serve markets beyond native load. Furthermore, such an excess capacity may allow more efficient allocation of generation resources and have a direct impact on lowering system-wide costs, in addition to other tangible and non-tangible benefits, such as lowering of the overall greenhouse gas emissions.

When and if such excess capacity can be justified based on the agreed-upon criteria, then the excess capacity can be designated as a primary or beneficial facility, and eligible to any applicable preferential treatment.

8.3.4 Right Sizing of Lines for Exports

The topic of this section and ways to address it were discussed in the previous two sections.

8.3.5 Early Purchase of Transmission Corridors Prior to Specific Identified Needs

This topic has been discussed elsewhere in this report, potentially under CEDA's future role in financing transmission, where CEDA may finance purchase, or finance purchasing of the option, to purchase property rights or right of use for specific identified needs or for potential future use.

8.3.6 Purchase of and Options On Larger Corridors Beyond Current Needs

The purchase of larger corridors or options on the purchase of larger corridors than is currently needed for 115-kV or 230-kV lines, would require a determination of needs based on economics or other agreed-upon criteria. Similar to other options in this section, the need can be determined through economic-based transmission planning analysis. Based on the determination of need beyond what is approved for reliability and designation, a PUC can require preferential treatment of incentives and cost recovery for the purchase or the option to purchase excess corridor property.

8.3.7 Construction of Towers Expandable from Single to Double Circuits

The same discussion and reasoning used in the above sections, applies to this case. If the underlying economic-based transmission planning analysis provides a justification for a future upgrade of a currently approved transmission project, with the expectation that such an upgrade would be needed in a reasonable time frame, then right sizing of the transmission towers for future transmission capacity upgrades can be designated as a priority or beneficial facility, subject to preferential treatment in terms of financial incentives and cost recovery options.

8.3.8 Inclusion of Environmental/Carbon Considerations in its Cost Recovery or Certificate of Public Convenience and Necessity Process

Extension of criteria used by PUC in cost recovery and CPCN to examine and include environmental and carbon considerations, requires further discussions with the PUC. However, a cursory review of the relevant documents has not identified any potential restrictions on what attributes PUC may want to consider in its cost recovery or CPCN process. Consideration of these additional environmental attributes needs to be anchored on a firm systematic approach in terms of the identification of the attributes to be considered and the evaluation criteria that can provide a consistent ranking or valuation of the attributes. Upon determination of the relative merits of each project based on these agreed-upon additional attributes and their valuations on economic or some other ranking basis, then the PUC can make appropriate rulings on a consistent basis.

8.3.9 Public Utilities Commission Emergency Transmission Rules' Dockets

On June 11, 2008, the Colorado PUC opened an investigatory docket on the electric transmission issues. On January 28, 2009, PUC drafted a concept paper titled "Proposed Emergency Rules For Electric Transmission Lines," which among other transmission issues, addressed: 1) the definition of the "ordinary course of business;" 2) required transmission system studies; 3) guidance for electromagnetic field and audible corona noise; 4) land use zoning information; and 5) other information required to be filed with a CPCN application.

PUC requested that interested parties respond to the concept paper. Various parties responded and filed comments on the concept paper. The comments from PSCo, Tri-State, and Black Hills Energy, in effect, stated that pursuing emergency rules as proposed in the concept paper would not expedite the CPCN process as intended and in fact would cause delay. These parties were of the opinion that the emergency rules were not necessary and instead preferred a permanent rule making process. The other parties supported modifications to the existing rules to address the issues raised in the concept paper and offered many suggestions.

Based on the comments received, PUC decided not to issue emergency rules at that time and instead decided to undertake a series of pre-rulemaking workshops with specific topics. Prior to each workshop, PUC would distribute a detailed document outlining the topics and questions to be addressed, and interested parties would be asked to provide written comments on the information and questions provided in documents prior to the workshops. All comments are to be posted to the Commission's Web site. The first four meetings proposed included the following (the actual topics were modified from those originally proposed by the PUC):

- March 30, 2009: Definition of "in the ordinary course of business" and procedures surrounding a determination that no CPCN application is necessary; information to be filed with CPCN applications, fast-track process for CPCN applications; and other procedures, including definition of "beneficial energy resource;" and, procedures for CPCN applications that do not qualify for a fast-track process or other specified treatments.
- May 28, 2009 (the topic of this workshop was changed from the one originally planned): Level of long-term transmission planning information necessary for PUC review; expectations regarding coordinated transmission planning review among interested parties and the role for PUC staff in such efforts; and procedures for PUC oversight of the planning process and whether that is accomplished as part of CPCN applications, in separate biennial (or other) transmission planning dockets, as part of the Electric Resource Planning process, or in an integrated resource planning docket – combining generation resource and transmission planning.
- Originally scheduled for May 18, 2009: Default levels of reasonableness (for fast-track purposes) with respect to issues such as the electromagnetic field levels, corona noise levels, widths of rights-of-way, conductor configuration, and transmission structures. Based on discussions between the PUC and the stakeholders, it was determined that this set of issues would best be handled in written comments rather than at a workshop.
- June 22, 2009 (originally scheduled for July 13, 2009): Multi-state transmission projects; siting, permitting, cost allocation, and cost recovery issues and the PUC's authority (and constraints) with respect to such projects and issues; recent federal legislation (proposed or pending) addressing transmission; and pre-emption of the role of state commissions.

As of the writing of this report, the first three workshops have been held and stakeholder comments posted on the PUC Web site. PUC will use the results of these meetings and the ensuing discussions of all the interested stakeholders to improve the CPCN process.

9.1 Gap between Timing of Building Transmission and Building Generation

The Chairman of the IEEE Power Energy Society Transmission and Distribution Committee believes that building a typical long-distance transmission line in the US may take about seven years, starting with the siting process, until the transmission line actually comes into operation.[98]

The length of time taken to develop and complete a transmission line depends on the siting and permitting process and actual construction time. The siting and permitting process can become more complex if the transmission project traverses multiple states and is subject to multiple jurisdictions. In most cases, the construction of the line is actually less time-consuming than the siting and permitting process. Construction time is dependent on the terrain, the type of structures, and the weather during construction.

American Transmission Company's 220-mile transmission line from Duluth, Minnesota, to Wausau, Wisconsin took two years to build but eight years before that to win the permits.[99]

Another example is American Electric Power Co.'s $306 million, 90-mile power line from West Virginia to Virginia, which took 14 years to obtain permits, but only two years to build.[100]

On the other hand, wind energy plants require one- to three-year construction lead times.[101] The DOE's "20% Wind Energy by 2030" Report of July 2008[102] assumes a one-year construction period for a utility-scale wind project based on the Jobs and Economic Development Impact Model of the National Renewable Energy Laboratory.

Table 9-1 presents the expected construction times for various generation types assumed by the DOE's "20% Wind by 2030" Study in its modeling.

[98] http://www.innovation-america.org/archive.php?articleID=501

[99] http://www.nytimes.com/2009/02/07/science/earth/07grid.html

[100] http://www.hopeofgeorgia.com/?script=articles/view&id=54E8F1D83E4E475CA5FE9A2410B139EF

[101] http://www.rnp.org/renewtech/tech_wind.html

[102] http://www.20percentwind.org/

Table 9-1. Expected Construction Times of Various Technologies

Technology	Construction Time (Years)
Natural Gas Combustion Turbine	3
Combined Cycle Natural Gas Turbine	3
Conventional Pulverized Coal Steam Plant	6
Advanced Supercritical Coal Steam Plant	4
Integrated Coal Gasification Combined Cycle Unit	4
Nuclear	6
Concentrating Solar Power with Storage	3
Utility-Scale Wind Project	1

Source: "20% Wind Energy by 2030," U.S. Department of Energy Report, July 2008, Table B-12, except for utility-scale wind project construction time, which is provided in page 202 of the report.

The discrepancy between the development time of a typical utility-scale wind project (i.e., 1 to 3 years) and a typical transmission line (i.e., 7 to 10 years), creates the so-called "chicken and egg" situation, where renewable energy plants cannot be built without having transmission access, and transmission lines are typically not built without first having a generation plant completed and ready for interconnection.

9.2 Renewable Generation Financing before Transmission is Built

If a location is suitable for development of renewable energy plant that could be ready for electricity production in a year or two, but the transmission interconnection will not be available for a few more years, then the renewable energy developer may have no choice but to wait until the right moment before undertaking the development of the project.

In the absence of transmission interconnection, the best a plant developer can do is to secure the development rights and address all the siting and land use issues and proceed with the permitting process. However, it is quite unlikely that it can get financing until there is some certainty of transmission interconnection availability, which would then enable the plant to compete for and obtain a power purchase agreement, based on which it can secure the required financing for the plant's development.

In the absence of transmission interconnection, a fully-developed renewable energy plant will not have access to distant markets through the transmission grid, but it may be able to serve local load, i.e., a limited-distribution local area of residences, farms, and industries, or operate as a behind-the-fence power source for the local industry. The financing for such a plant could be secured based on the contracts signed with or expected revenues from the local load.

A renewable energy plant owner can become, with FERC approval, an "anchor" shipper/subscriber to a line to be built a few years out. This will not only increase the likelihood of the transmission line to be built, but will also provide a more certain positive outcome in view of the potential financial backers. However, the alignment of the timing of the commercial operation dates of both the renewable energy plant and the transmission line will be of the essence, since both the terms of potential contracts and power purchase agreements and the required financing will depend on the proper timing.

According to the president of Trans-Elect:[103]

> "To illustrate, the WCI project will take approximately seven years from inception to commercial operation. It will have to go through multiple jurisdictions for permitting in Wyoming and Colorado. During that time, it will have to bear all the risks associated with construction, land acquisition, and financing. At the same time, the wind energy generators who are WCI's customers are able to develop their projects over as short as a three-year period. This timing difference represents risk to the transmission developer; it will necessarily need to begin its work and expenditures substantially in advance of actual generation project construction. If this timeline is not met for reasons beyond its control, this also represents risk to the renewable resource developer."

9.3 Role for the Colorado Clean Energy Development Authority in Financing Transactions

Should CEDA receive the statutory authority to issue bonds and engage in the financing of needed transmission, it can play a critical role in development of transmission projects in Colorado. All of the following financing options assume that CEDA or an equivalent state transmission infrastructure authority will have the authority to raise financing and issue bonds, and otherwise engage in transmission development in partnership with other transmission providers.

9.3.1 Loan Guarantee for New Transmission

CEDA can provide loan guarantees, similar to federal loan guarantees, for development of transmission in Colorado. As with the federal program, candidate projects would need to meet an eligibility criteria (to be developed), and be subject to a state-approved process for a transmission planning study and designation of the proposed project as a "priority" transmission for Colorado.

9.3.2 Incremental Capacity Financing beyond Approved Level

CEDA can provide incremental financing for transmission capacity above levels approved by the PUC. The additional capacity to be financed should be based on an

[103] http://www.wiresgroup.com/images/McCoy-FERC-Statement-081014.pdf

economic cost/benefit analysis that would evaluate the economic impact of additional transmission capacity for a long-range planning horizon on providing access to future renewable energy resources, and the overall impact on producer surplus, customer surplus, system generation costs, wholesale and retail rates, and potential climate impact. Cost of financing would be recovered by CEDA through an anchor shipper/subscriber and/or open season process, or through FERC-approved transmission rates for firm and non-firm transmission.

9.3.3 Financing for Corridor Purchase or Options

CEDA can also provide financing for parties interested in purchasing transmission corridors for future transmission development

With a view on future transmission development, CEDA may purchase a property right or a right-of-way to be used for a future transmission facility, or alternatively purchase an option to purchase property (rather than the real property), which CEDA may view as a potentially suitable path within a possible future transmission corridor in Colorado, even before a decision is made on the final makeup of the transmission corridor. The option to purchase will keep such candidate paths in reserve until final decisions on the transmission corridors are made.

9.3.4 Financing to be Paid Back as Capacity is Filled Out

CEDA may finance the purchase of capacity on a line to help jumpstart the development of needed transmission lines. As the capacity is filled out by prospective transmission users, any loans financed by CEDA would be paid back.

9.4 State Incentives and Policies

State policy makers have started considering ways of providing incentives, some in the form of financial tools such as loans, grants, and bonds, to foster transmission developments in their states that would provide access to their remote and locationally constrained renewable energy resources.

9.4.1 Examples of State and Regional Incentives

The general approach is that transmission projects determined to be necessary to support a utility's plan to meet RPS requirements would be deemed a priority electric transmission project and satisfy a certificate of need, which then gives the PUC authority to approve transmission cost adjustments on a timely basis.

This state-approved rate recovery process allows utilities to recover costs on a timely basis with a return on investment at a level most recently approved or another rate consistent with the public interest. A return on CWIP also is allowed to be incorporated into the rates.

Examples of the roles of a few states in providing incentives for transmission development, and highlights from a number of innovative federal approaches to RTO and merchant transmission development, are provided below:

Texas Transmission Policy

Texas has passed legislation that authorizes their PUC to require electric utilities to construct or enlarge transmission facilities to meet Texas RPS goals.[104] Texas law SB 20 also provides cost recovery incentives for transmission projects that support RPS goals. Such projects automatically are deemed used and useful, and prudent and includable in the rate base, regardless of the utility's actual use of the facilities. Texas legislation effectively socializes the cost of building transmission to renewable resources as part of its initiative on renewable energy zones.

California Multi-User Resource Trunklines Financing

In 2007, the CAISO proposed, and the FERC approved, an innovative financing approach, the so-called "third path," that has the transmission owner pay all capital costs up front.[105, 106] This is what is referred to as "CAISO-Type Financing" elsewhere in this report as one of the transmission cost allocation methods. Until the transmission investment is later recouped from wind generators as they interconnect to the transmission line, the transmission owner begins recovering the investment from its retail customers.

The California Transmission Financing Proposal is intended to enable access by remote renewable resources, such as Tehachapi Area wind resources, to the high voltage transmission grid. CAISO refers to these transmission lines as Multi-User Resource Trunklines.

The CAISO proposes the following rate treatment for Multi-User Resource Trunklines constructed by existing or new Participating Transmission Owners:

- Participating Transmission Owners that construct Multi-User Resource Trunklines will be permitted to reflect in their Transmission Revenue Requirement and in the CAISO's Transmission Access Charge the costs of trunkline facilities which are not being directly recovered from generation resources.
- As new generation resources are constructed and interconnected to a Multi-User Resource Trunkline, the costs of the capacity required by those resources will be directly recovered from such resources, thereby reducing the impact on transmission ratepayers by reducing the costs of the Multi-User Resource Trunkline included in the Participating Transmission Owners' Transmission Revenue Requirement and the Transmission Access Charge.

[104] Texas Legislature SB 20, Legislative Session 79(1), signed by Governor Rick Perry on August 2, 2005, and effective on Sept. 1, 2005. http://www.capitol.state.tx.us/

[105] http://www.caiso.com/1bc5/1bc5b6204ee20.pdf

[106] http://www.ballardspahr.com/press/article.asp?ID=1611

- When all of the capacity of the Multi-User Resource Trunkline is utilized and paid for by generators, transmission ratepayers would no longer face any cost responsibility for these facilities.

The CAISO proposes the following eligibility criteria for the proposed rate treatment for Multi-User Resource Trunklines:

- The costs of the Multi-User Resource Trunkline, which is a non-network facility, would not otherwise be eligible for inclusion in the CAISO's Transmission Access Charge.
- The transmission project must provide access to an energy resource area in which the potential exists for the development of a significant amount of location-constrained energy resources.
- The transmission project must be turned over to the CAISO's operational control.
- The transmission project must be a high-voltage transmission facility designed primarily to serve multiple location constrained resources that will be developed over a period of time.
- To be eligible for the financing treatment proposed herein, a transmission project would have to be evaluated and approved by the CAISO in the context of a prudent CAISO transmission planning process, thereby ensuring that the project will result in a cost-effective and efficient interconnection of resources to the grid.
- To limit the cost impact of the proposal on ratepayers, there would be an aggregate cap on the total dollars associated with Multi-User Resource Trunklines that could be included in Transmission Access Charge rates. Specifically, the total investment in Multi-User Resource Trunklines that can be included in the Transmission Revenue Requirement and the Transmission Access Charge cannot exceed 15 percent of the sum total of the net high-voltage transmission plant of all Participating Transmission Owners, as reflected in their Transmission Revenue Requirement and in the Transmission Access Charge.
- To limit the risk of stranded costs due to abandoned investment, the transmission project must demonstrate adequate commercial interest by satisfying the following two-prong test before actual construction can commence:
  - A minimum percentage of the capacity of the new Multi-User Resource Trunklines -- an order of magnitude or 25 to 30 percent -- must be subscribed pursuant to Large Generator Interconnection Agreements.
  - There must be a tangible demonstration of additional interest in/support for the project -- an order of magnitude of 25 to 35 percent -- above and beyond the capacity covered by Large Generator Interconnection Agreements.

Minnesota CapX2020

CapX2020[107] is a joint initiative of 11 transmission-owning utilities in the state of Minnesota and the surrounding region to expand the electric transmission grid to

[107] http://www.capx2020.com/index.html

ensure continued reliable and affordable service. Customer demand in the CapX2020 region is projected to increase 4,000 to 6,000 MWs by 2020. In order to meet this increasing demand, as well as support the push for renewable energy expansion, several large transmission projects have been proposed. These projects consist of 68 miles of 230-kV and 600 miles of 345-kV transmission lines and they are projected to cost an estimated $1.4 to $1.7 billion. These projects will span over the states of Minnesota, North Dakota, South Dakota and Wisconsin.

CapX2020 is made up of IOUs, electric cooperatives and Munis. These utilities serve the majority of customers in Minnesota and the surrounding region. CapX2020 transmission owners are generally located within the MISO region. Under the MISO OATT, CapX2020 transmission owners may elect to either:

- Recover their ownership costs associated with CapX2020 facilities through transmission rates that would be paid by transmission customers within MISO.
- Receive transmission rights that could be used to hedge transmission congestion costs within MISO (i.e. merchant transmission treatment).

These recovery mechanisms apply to both jurisdictional and non-jurisdictional CapX2020 owners. In addition, certain CapX2020 transmission owners have filed for FERC approval of incentive rate treatment under Order 679.

It is anticipated that CapX2020 will provide benefits to all electricity customers in Minnesota and the surrounding region by making the electric transmission system more robust and reliable. In addition, CapX2020 will promote the expansion of the renewable industry in Minnesota resulting in benefits for the entire state and region. For example, CapX2020 will provide greater access to the region's tremendous wind energy potential. Minnesota ranks ninth in the country for wind energy potential with North Dakota ranking first and South Dakota ranking fourth. The transmission lines to be built under CapX2020 will add nearly 2,000 MW of wind capacity to the transmission grid. Minnesota currently needs about 5,000 MW of renewable energy to meet the renewable energy standards of the state, which has one of the nation's most aggressive renewable energy laws.

Southwest Power Pool-Balanced Portfolio Planning

The SPP is planning a major, extra high-voltage, economic transmission expansion upgrade project totaling over $700 million. This undertaking is to be funded by the FERC-approved "postage stamp" rates applied to SPP's transmission-owning members across the region.[108]

The new approach used by SPP is to evaluate the benefits of a group of economic upgrades, called "balanced portfolio approach," rather than evaluating individual upgrades on a project-by-project basis. The balanced portfolio approach is based on a group-undertaking and consensus-building approach, which also results in alleviating potential disputes that may arise from the construction of a single project that may

[108] http://www.spp.org/publications/Transmission_Project_Portfolio_Approved_4_29_09.pdf

benefit one zone but not others--the portfolio approach. The FERC-approved postage stamp rate facilitates cost recovery and avoids rate pancaking.

Partnership in Wyoming-Colorado Intertie

Colorado's neighbor to the north provides an example of state action to promote transmission investment. As discussed elsewhere in this report, WIA's goal is to diversify and grow the state's economy through the development of its electric transmission infrastructure. The authority also is responsible for planning, financing, building, maintaining, and operating electric transmission and related facilities.

The authority is authorized to issue up to $1 billion in bonds to finance new transmission lines to support new generation facilities in the state; own and operate lines in instances where private investment is not offered; enter into partnerships with public or private entities to build and upgrade transmission lines; investigate, plan, prioritize, and establish corridors for electric transmission; and establish and charge fees and rates for use of its facilities in consultation with the Wyoming Public Service Commission and other related government entities.

The WCI Project is a public/private development partnership involving the Wyoming Infrastructure Authority, Trans-Elect Development Company LLC, AES Corporation, and WAPA, with Trans-Elect leading the development effort. The partnership was first announced September 27, 2005. On April 28, 2009, LS Power announced that it had purchased the rights to the WCI Project held by AES Corporation.

In 2008, an "Open Season" auction was held to sell the capacity to successful bidders. As part of the Open Season process, the project sponsors had offered up to 850 MW of transmission capacity in a public auction. This has resulted in 585 MW of capacity purchase commitments from creditworthy parties. GreenHunter Wind Company, LLC and Duke Energy Ohio, Inc., two wind developers with wind farms under development near Chugwater, Wyoming have secured capacity on the WCI project. The project sponsors are optimistic that the remaining 265 MW of capacity will be sold. The project sponsors expect to complete the siting, permitting, and construction of the line and begin operation by mid-2013.

The new transmission line will be regulated by the FERC and the Open Season was designed to comply with federal regulatory policy.

WCI filed a petition seeking authorization to charge negotiated rates for firm, point-to-point transmission service on the proposed 180-mile, 345-kV transmission project that will originate in Wyoming and terminate in Colorado. WIA has supported the development of the project with a commitment funding 50 percent of the project's development costs. Should the project be built, and upon WCI's financing, monies expended by WIA (with a reasonable rate-of-return) will be refunded to the state.

As demonstrated by WCI's application, the necessary requirements for Commission approval for a merchant project that is not within an RTO have been met. As represented by its Open Season Report, subscription to the project's capacity was established through an open season process that was non-discriminatory, fair, and transparent. The project's sponsors will take ultimate financial responsibility and market risk for the costs of the project. Service will be provided under an approved OATT.

WIA has asked the Commission to provide the project sponsors with the prompt decision they request, by May 10, 2009. Prompt action on WCI's application and requests for waivers will provide regulatory certainty critical to the timely financing and construction of the project. As of this writing, no action appears to have been taken by the Commission in response to WIA's request.

The remaining unsold capacity, 265 MW, is now being made available on an application basis in conformity with the WCI OATT that is posted on the WCI Web site. Qualified applicants will be awarded capacity at the posted minimum price after a posting period of 30 days following the submittal of a completed application, unless applications exceed the 265 MW available, which will trigger an auction process.

9.4.2 Potential Federal Role

Incentive-Based Rates

Federal entities, and FERC in particular, can play a critical role by adopting a host of innovative policies that would facilitate development of needed transmission in various parts of the US. Possible policies include:

- Extending the federal loan guarantee programs.
- Extending the federal investment tax credits.
- Developing incentive-based rate treatments, including higher return on equity, and provisions to allow earlier and more certain cost recovery.
- Allowing an Anchor Shipper/Subscriber model for renewable generation and transmission partnership (discussed below).
- Adopting a more forceful policy towards creation of independent transmission companies to promote competition in the market and reduce market power.
- Adopting more generous rate incentives for transmission providers which help develop or join RTOs.
- Continuing the federal push for creation of more competition and a level-playing field in all regions of the US and mitigation of market power in transmission.
- Extending the FERC 890 and OATT filing rules to require regional long-range transmission expansion planning by designated regional authorities, using both reliability and economic criteria, and covering the transmission service territories of all transmission providers in the region. FERC can provide preferential treatment to any proposed transmission project that is identified as a priority project in the regional analysis based on its positive reliability, economic, environmental, and resource sustainability attributes.
- Promoting development of a more uniform and consistent policy on cost allocation and cost recovery that would enable more simplified regional point-to-point transmission rates across multiple jurisdictions.

- Encourage development of virtual control areas with wider geographic extent to promote a more efficient allocation and utilization of region-wide energy, capacity, and operating reserve resources, with transparent and non-discriminatory pricing of various market products.

There are other drivers on the national level that would provide an indirect impetus for development of new transmission projects. National legislation and federal rules that advance the development of renewable resources would indirectly help promote development of transmission infrastructure necessary to access such resources, which are typically locationally constrained. The most important national policies that will indirectly necessitate development of transmission infrastructure include:

- Making federal renewable energy production tax credit permanent.
- Adopting a national RPS policy with a national REC market.
- Passing Clean Energy and Climate Change legislation (with appropriate pricing of the environmental externalities).

Transmission Anchor Shipper/Subscriber

An example of an innovative federal approach to providing incentives for new transmission development is the Transmission Anchor Shipper/Subscriber.

On February 19, 2009, FERC approved flexible rates for two 500-kV DC transmission projects that are considered novel in their design and impact.[109]

The two transmission projects, Chinook Power Transmission, LLC and Zephyr Power Transmission, LLC, about 1,000 miles in length, will deliver wind-generated electricity from Montana and Wyoming to consumers in Nevada and other Southwestern states. Chinook and Zephyr are wholly owned subsidiaries of Northern Lights, Inc., a wholly owned, indirect subsidiary of TransCanada Corporation.

These proposed projects are considered merchant in nature, which implies that the developer assumes all market risk, with revenues based on transmission fees, since they have no native retail customers who would provide a vehicle for project cost recovery. However, FERC's new policy will allow the transmission owners to use an "anchor" customer model, in which each transmission developer contracts with a wind generation company for half of the capacity on its line before it offers the remaining capacity to others in an open-season process.

[109] http://www.ferc.gov/news/news-releases/2009/2009-1/02-19-09-E-15.asp

9.5 Alternative Cost Recovery Process

9.5.1 Retail Backstop Rate Recovery for Lines not Approved by FERC

An example of retail backstop rate recovery for lines not approved by FERC is the California "third way," otherwise known as MURT financing, or the CAISO-type financing described earlier in this report. The approach still requires FERC's approval, but it enables the recovery of costs through PUC-approved retail rates, if the state considers the transmission project having societal benefit for the state. Under the California plan, until the transmission investment is later recouped from wind generators as they interconnect to the transmission line, the transmission owner begins recovering the investment from its retail customers.

9.5.2 Public Utilities Commission Accounting for "Non-Utility" Benefits

In its approval of transmission lines, the Colorado PUC can account for or include non-utility benefits, which accrue to a wider set of stakeholders and to the Colorado power sector and transmission system in general. The non-utility benefits may include the climate impact (by enabling access to cleaner energy), the impact on total system costs (through enabling utilization of more efficient resources), system-wide economic impacts on customer rates (through enabling access to less costly resources), and contribution to resource diversity and resource sustainability.

A process would need to be developed to guide the identification of such non-utility attributes and projection of their benefits onto a value yardstick. Without a systematic approach and an objective valuation scale, PUC decisions could devolve into more subjective decision making.

9.5.3 Incentives for Building New Transmission Beyond Need

SB 100 applies only to IOUs in Colorado. The first logical action would be to extend SB 100 to the other non-jurisdictional transmission providers. Since the PUC's authority, as specified by state law, is a matter of legal argument, the extension of SB 100 to non-IOUs may require clarifying action by the Colorado legislature.

Providing additional incentives that can motivate building new transmission beyond what is possible through SB 100 would require addressing the underlying interests of the transmission providers.

These incentives could be financial, in the form of higher rates of return for the additional incremental transmission development, cost recovery incentives, tax exempt financing, and a host of similar approaches.

Non-financial incentives include creating a process for expedited permitting, addressing the inherent risks of building additional transmission capacity without the promise of future firm transmission customers through backstop rate guarantees.

9.6 Transmission Planning Options

9.6.1 Transmission Planning in the Region

Coordinated transmission planning can help avoid widespread outages, increase reliability, and reduce costs. Interconnected systems provide advantages such as greater reliability, access to remote generation, increased wholesale electricity transactions, and the ability for utilities to share reserves. On the other hand, in interconnected systems, blackouts and system disruptions in one part of the system can instantaneously impact the rest of the system. A case in point is the blackout in the northeast portion of the Eastern Interconnect in August of 2003.

The interconnectedness of transmission grids necessitates regional planning. In Colorado, and its neighbors in the Rocky Mountain and southwest regions, the regional planning is based on coordination and collaboration at the sub-regional level, rather than a more cohesive centralized approach at a wider regional level.

Colorado and the Rocky Mountain region transmission owners collaborate and coordinate their long-term planning through involvement in Colorado Long Range Transmission Planning Group, CCPG, WestConnect, and WECC/TEPPC, with Colorado Long Range Transmission Planning Group and CCPG being the principal venues for their planning activities. At a higher level (wider footprint), WestConnect acts as the coordinator of the findings of the sub-regional planning groups, which include CCPG, SWAT, and Sierra Sub-regional Planning Group. Hence, the planning studies are still done on a sub-regional level, so it is only the results which are coordinated and disseminated to ensure that the underlying assumptions are not contradictory. The WECC/TEPPC efforts are focused on the economic based planning analysis on the regional level.

Colorado and the Rocky Mountain region transmission owners are also involved with planning of joint regional transmission developments if they are partners in the development and/or ownership. Examples are WCI and HPX.

Roles and processes of each of the regional planning entities, such as WECC/TEPCC, WestConnect, CCPG, and Colorado Long Range Transmission Planning Group, have been described elsewhere in this report.

An important characteristic of the transmission planning in Colorado, in particular, and in the Rocky Mountain and desert southwest region, in general, is that it is based on voluntary coordination and collaboration of various transmission providers. There is no single regional transmission plan. The end result of the process is a collection of various individual studies on a sub-regional level. The findings of CCPG, WestConnect, and WECC/TEPCC are not necessarily actionable or enforceable. In a sense, the transmission planning process in Colorado and the region is a bottom-up approach.

Other than the guidelines and constraints imposed by the requirements of FERC 890, Colorado SB 100, and the PUC's CPCN process, each transmission provider's transmission plan is still designed and tailored to addressing the needs of the individual provider. In contrast, in the established RTOs and ISOs, the long-term regional transmission expansion planning is a top-down process, where long-term transmission expansion plans are developed with a regional perspective in mind. Although it should be added that even at the RTO and ISO levels, transmission planning is still geared to satisfying future reliability requirements more than meeting some economic optimality or societal cost-benefit criteria that would encompass not only reliability but also economic and environmental considerations and measures.

The question is whether the overall regional societal benefits of an interconnected transmission system organically developed based on the ad hoc and bottom-up approach of disparate transmission providers, converges to the regional societal benefits of a system developed based on a top-down regional transmission planning process. In other words, is there an "invisible hand" that guides the self-interested behaviors of individual transmission providers to collectively benefit the society at large? Without making an explicit judgment on the merits or demerits of the current approach to transmission planning, it is worthwhile to consider the positive aspects of transmission planning as carried out in other regions.

9.6.2 Transmission Planning in Other Regions

In regions with established RTOs and ISOs such as SPP, MISO, ISO-NE, New York independent system operator, PJM, and the Electric Reliability Council of Texas, transmission planning is performed on a regional basis, with annual studies that are usually described and presented in their annual Long-Term Transmission Expansion Planning reports.

Here we focus on a number of general themes that are the main features of regional transmission planning and attempt to make a number of observations. In particular, we consider the following attributes:

- Regional authority.
- Regional extent.
- Underlying load and resource assumptions.
- Economic and/or reliability criteria.
- Planning horizon.

Regional Authority

The organized RTOs and ISOs have demonstrated the feasibility and even desirability of a collaborative approach. In fact, regional long-range transmission expansion planning is an essential task of these organizations. This compels collaboration and cooperation on a region-wide basis, and treats the region-wide transmission system as one whole organic system rather than a collection of disparate and disjointed systems, although physically interconnected. The overarching perspective is the consideration of the system-wide requirements (albeit more reliability than economic based), with lesser emphasis on the interests of individual member entities in isolation from others.

To some extent, WECC's TEPPC, WestConnect, CCPG, and the Colorado Long Range Transmission Planning Group provide the venue and the forums for coordinated and collaborative planning efforts by various transmission owners in Colorado and the region. However, the voluntary nature and self-interest focus of these efforts, which is the main difference between these and the long-range transmission expansion planning by RTOs/ISOs, implies that these efforts are ad hoc, piece-meal, and fragmented

In Colorado, by comparison, there is no single dominant organization with full authority to carry out the regional long-range transmission planning function, determining the region-wide needs, and bringing on the implementation of the desired regional transmission by either the traditional transmission owners, or if they lack interest or motivation, by a regional authority in partnership with regional entities and even merchant providers.

Regional Extent

The current regional coordination and collaboration is restricted in its geographic reach. An equivalent effort in the Western Interconnection compared to the long-range planning undertaken by PJM would be a WestConnect-wide effort. However, WestConnect acts more as a coordinator of the efforts of its sub-regional planning groups such as CCGP, SWAT, and Sierra Sub-regional Planning Group. There is no long-range transmission expansion planning effort -- other than the TEPPC's economic modeling, which is not technically a regional long-range transmission expansion planning -- that covers the whole region and considers all potential generation resources. Most current studies are at the state level except for specific transmission proposals spanning multiple states.

There is no mechanism to "roll up" the existing regional and inter-regional plans and to provide a seamless whole picture of a future regional transmission system with consideration of WECC-wide future potential generation.

In contrast, in the Eastern Interconnection there was a meeting by 17 US and Canadian planning authorities to perform an Eastern Interconnection-wide transmission planning for the eastern US. The importance of an "interconnection-wide planning authority" is highlighted in the following statement by SPP, one of the entities involved.[110]

> "The impetus for the meeting included the Obama administration's focus on the electric grid, integration of renewable energy, and call for an interconnection-wide planning authority; the need to improve energy security and reduce dependence on foreign oil; the ongoing climate change discussion and need to reduce greenhouse gas emissions; and the call to expedite siting and construction of new transmission."

Underlying Load and Resource Assumptions

Current transmission planning methods carried out by franchised utilities with native retail or wholesale customers, usually restrict their views to the amount of generation that would be needed to satisfy the loads of their retail and wholesale customers plus

[110] http://www.spp.org/section.asp?pageID=18

an installed reserve margin to meet their prescribed reliability criteria. This restricted view is actually appropriate for a vertically integrated utility and a regional cooperative or transmission and generation association with defined service territories and well-defined customer base, whether retail or wholesale. However, in an environment where independent power producers compete with the traditional suppliers and transmission grid is considered more as a public highway rather than a private pathway, a broader view of the functions of the transmission grid is warranted.

Such a perspective will treat the transmission grid as a public network with an obligation to provide unfettered access to independent producers, whose ultimate customers may not even reside in the service territory of the transmission provider. In this broader paradigm, a more appropriate transmission planning process would not restrict the footprint of the transmission system to the service territory of the provider’s own customers. The transmission grid should not only be sized for servicing the native customers in the service territory of the transmission provider, but should also be “right sized” to function as a transit pipeline for additional wheeling of power where either or both of the injection and delivery points of the wheeled power may be located beyond the service territory of the transmission provider.

Economic versus Reliability Impetus

Traditional transmission planning is concerned with reliability as the foremost attribute for consideration with lesser regard for the overall system-wide economic impacts (i.e., associated system-wide costs and benefits) of the proposed transmission projects.

Traditional transmission planning involves application of power flow studies and stability analysis considering snapshots of time, such as peak conditions in a future year, with assumptions on load and resources representative of that particular juncture in time. These studies also include a number of scenarios of the main drivers as variants from a base-case assumption. For instance, the scenarios may include assumptions on higher load growth, or additional generation resources in a particular area.

The overall objective of the traditional transmission planning is to study the transmission requirements needed to meet the well-defined reliability requirements under future conditions while ensuring availability of adequate capacity to meet the energy needs of the transmission provider’s electricity customers.

However, a broader view warrants consideration of other attributes beyond reliability, such as the system-wide economic and environmental impacts.

For instance, reliability-based transmission planning would meet both the target requirements for reliability and also the necessary carrying capacity to meet the customers’ loads. A reliability-based transmission development would, by definition, relieve current congestions or prevent future congestions, since without the planned transmission the needed electric energy would not be able to reach its growing customers.

Yet, any new transmission would have far-reaching economic impact on other parts of the interconnected transmission grid -- simply because electric power flows follow certain physical laws that make them impervious to being controlled or confined to a geographically defined footprint. In other words, power injection and electricity consumption at any point in an AC interconnected system would impact flow on almost every line in the system, because power flows in the path of least resistance (defined by the physical characteristics of the transmission grid and its topography and topology). Another common term for this phenomenon is the “loop flow.” Consequently, a transmission upgrade in one region may result in either relieving or exacerbating transmission congestion in some other region on the interconnected grid.

Transmission congestion usually results in the creation of either a high-priced load pocket or a low-priced supply pocket. In the high-priced load pocket, the less costly generation outside the pocket cannot reach the load inside the pocket. In the low-priced supply pocket, the less costly generation cannot reach the load outside the pocket. Consequently, a transmission upgrade can have varying degrees of impact on generation and flow patterns, causing higher or lower costs and prices at various points on the transmission grid. In economic terms, this translates into higher or lower “consumer surplus,” i.e., net benefits to the consumers, or higher or lower “producer surplus,” i.e., net benefits to the producers, due to changes in underlying costs and price patterns. In other words, a transmission upgrade may result in a variety of economic winners or losers beyond its immediate service territory. Although the net system-wide impact of additional transmission would be expected to be positive, the economic impact could be positive in one region and negative in another region, although not necessarily a net “zero-sum” situation.

In markets based on nodal pricing (i.e., pricing that is reflective of actual cost of service by location and time), there is an immediate impact on locational-based prices (as seen by generators), and zonal prices (as seen by customers). The current traditional transmission planning is not equipped to account for these economic impact evaluations. The kind of analysis carried out within WestConnect, or more properly by the sub-regional groups such as CCPG, do not account for such economic impacts, since they are concerned primarily with the reliability impacts in one or a few future snapshots in time.

The main exception to the traditional planning in the WECC footprint is the sort of analysis being performed by WECC’s Transmission Expansion Policy and Planning Committee. The planning studies of TEPCC appear to be based on chronological security constrained economic dispatch analysis. Such an analysis attempts to model optimal dispatch of generation with consideration of transmission topology and respecting generation- and transmission-specific constraints on an hour-by-hour basis, with the objective of keeping total system costs at a minimum. Such an analysis provides for determination of resulting local, regional, and system-wide costs and benefits.

Combining such an analysis with various transmission scenarios in an iterative manner with power flow analysis at selected junctures in time, would result in the selection of transmission expansion plans that not only meet the reliability requirements, but also result in the least cost/highest benefit transmission options on a system-wide basis, assuming that the costs and benefits are defined using appropriate metrics that reflect true values of economic, environmental and other attributes. A case in point is MISO, which has suggested moving from a traditional approach to transmission planning based on meeting reliability targets to ensuring optimal economic value of expansion, which entails accommodating renewable resources.

Planning Horizon

Long-term transmission planning horizons vary by region and utility, but a 10-year planning horizon appears to be the norm. In Colorado, the common argument for a 10-year planning horizon is the uncertainty regarding future events and the inability to provide a base case view of the drivers and load and generation projection beyond a 10-year time horizon. The 10-year time frame appears to be in accordance with NERC standards, as mandated by Congress in the EPAct 2005.

Although a 10-year planning horizon is typical, a cursory investigation indicates that a longer than 10-year planning horizon is not that uncommon. Although not an exhaustive list, the following regions have transmission planning horizons that are either longer than 10 years, or as some of the direct quotes illustrate, have made policy statements favoring a longer than 10 years planning horizon:

- Colorado PUC Staff:[111] "Staff asserts the present long term time frame of 10-years is inadequate and should include a longer horizon looking out 20, 30, or perhaps 40-years in order to identify transmission corridor needs."
- BH/Colorado Electric Utility Company SB07-100 Bench Mark Load Scenarios: Includes a 2027 Summer Peak scenario intended to identify long range needs and to define and plan for potential future upgrade needs.[112]
- Alberta Electric System Operator (AESO): "20-year Transmission System Outlook and 10-year Transmission System Plan."[113]
- British Columbia: "BCTC is proposing a 20 year investment analysis horizon, consistent with the BC Hydro IEP."[114]
- Ontario Power Authority: "However, the planning horizon that the Ontario Power Authority works to is 20 years…"[115]

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[111] "Comments From Staff of The Commission Concerning Electric Transmission", Docket No. 08I-227E, April 10, 2009

[112] http://www.blackhillscorp.com/trasmission/Stakeholder_Meeting_Presentation_42209.pdf

[113] "AESO Consolidated Long-term Transmission System Plan, AESO Stakeholder Consultation", September 3, 2008.

[114] British Columbia Transmission Corporation, "Transmission Expansion Policy (TEP), Investment Criteria and Implementation Process", June 11, 2007.

[115] "Developing a Strategic, Long-Term Transmission and Distribution Policy for Renewable Energy in Ontario", Jan Carr, CEO, Ontario Power Authority. http://www.powerauthority.on.ca/Storage/12/785_DevelopingStrategic.pdf

- Midwest ISO: "To accomplish long range economic transmission development, a planning horizon of at least 15 years is necessary to encompass the reality that large transmission projects nominally require ten years to complete."[116]
- ISO New England: "In order to recognize the long-term nature of these developments,[117] the plan should have a time horizon significantly beyond the current Regional System Plan (RSP). (The RSP is focused on ensuring reliability of the regional power grid within a ten-year timeframe in accordance with the North American Electric Reliability Corporation (NERC) standards as mandated by Congress in the Energy Policy Act of 2005)."
- NY ISO: "Energy Law Section 6-108 required that reliability be assessed over the term of the planning period, which is defined under Energy Law Section 6-104 to be 20 years."[118]

  Nevertheless, the actual reliability analysis in NY ISO appears to be based on a 10-year planning horizon: "The CRPP is an assessment, over a 10-year planning horizon, to determine if the bulk power system can adequately supply the aggregate electric power and energy requirements of electricity consumers at all times, taking into account planned and unplanned outages of system components and sudden disturbances such as electric short circuits or unanticipated loss of system components."[119]
- PJM: "PJM's RTEP process includes both five year and 15-year dimensions. Five-year-out planning enables PJM to assess and recommend transmission upgrades to meet forecasted near-term load growth and to ensure the safe and reliable interconnection of new generation and merchant transmission projects seeking interconnection within PJM."

  "The 15-year horizon permits consideration of many long-lead-time transmission options. These options often comprise larger magnitude transmission facilities that more efficiently and globally address reliability issues. Typically, these are higher voltage upgrades that simultaneously address multiple NERC reliability criteria violations at all voltage levels. A 15-year horizon also allows PJM to consider the

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[116] Midwest ISO, "MTEP 08, The Midwest ISO Transmission Expansion Plan", November 2008. http://www.midwestmarket.org/publish/Document/279a04_11db4d152b9_-7d8d0a48324a/2008-11_MTEP08_Report.pdf?action=download&_property=Attachment

[117] Reference to the "integration of renewable and carbon-free resources into the grid", in letter of Gordon van Welie, President and CEO of ISO New England to the Honorable John Baldacci, Governor of State of Maine, on February 2, 2009. http://www.maine.gov/governor/baldacci/policy/2009-02-02%20Gov.%20Baldacci.pdf

[118] New York State Planning Board, "Report on the Reliability of New York's Electric Transmission and Distribution Systems", November 2000. http://www.nyserda.org/sep/t&dreport.pdf

[119] NYISO, "2008 Comprehensive Reliability Plan", July 15, 2008. http://www.nyiso.com/public/webdocs/newsroom/press_releases/2008/2008_Comprensive_Reliability_Plan_Final_Report_07152008.pdf

aggregate effects of many system trends including long-term load growth, impacts of generation deactivation and broader generation development patterns across PJM. This could include reliability issues posed by clusters of development based on innovative coal or nuclear technologies, renewable energy sources, or proximity to fuel sources."[120]

- California: "Transmission projects require an 8 to 10 year lead-time. Many of the current interconnections being considered in California were first identified 20 to 30 years ago. Transmission projects have long lives. Hence, it is critical to address future transmission from a strategic long-term perspective. A good August 2003 target for California's future transmission grid would be to look ahead 25 to 30 years."

  "Traditional approaches to planning transmission are inadequate. For example, there are no definitive generation expansion plans going out 10 years that provide guidance for future transmission. Consequently, a strategic approach with a long-term time horizon to build needed strategic interconnections to market hubs and resource-rich regions is needed.

  Transmission has an 8- to 10-year lead time – the 5- to 10-year planning horizon is not enough."[121]
- CapX2020: Appears to have a 15 year planning horizon.[122]
- In addition, many states appear to have longer than 10 years planning horizon for their in-state IRP and transmission planning studies:
  - Idaho: "The scope of the process is to develop a transmission plan consistent with a twenty (20) year planning horizon, as outlined in Attachment K." [123, 124] Two utilities have 20-year horizons. One uses a 10-year horizon.[125]

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[120] PJM 2008 Regional Transmission Expansion Plan, February 27, 2009. http://www2.pjm.com/planning/downloads/rtep-2008/2008-rtep-report.pdf

[121] "Planning For California's Future Transmission Grid", Review of Transmission System, Strategic Benefits, Planning Issues And Policy Recommendations", Prepared by: Electric Power Group, LLC, For California Energy Commission, August 2003.

[122] CapXPrestoSDEIA.pps

[123] In reference to "Local Transmission Plan Objectives and Scope", in "Idaho Power Study Plan", 2008-2009 Local Transmission Plan, Rev 1 07-07-2008. http://www.oatioasis.com/IPCO/IPCOdocs/Idaho_Power_Study_Plan_2008_and_2009_Biennial_Local_Transmission_Plan.pdf

[124] IDAHO POWER COMPANY, "Attachment K, Transmission Planning Process", DRAFT, September 14, 2007. http://www.oatioasis.com/IPCO/IPCOdocs/IPC_version_Attachment_K_9-14-07.pdf

[125] Regulatory Assistance Project Electric Resource Long-range Planning Survey, State: Idaho, Survey Date: 9/22/05.

- British Columbia: “Not currently specified, but under the Commission’s former IRP Guidelines (prior to the Court of Appeal ruling) indicated that the forecasts and the resource plans should be over the same timeframe, generally 15 to 20 years into the future.”[126]
- Oregon: Appears to be 20 years.[127]
- Washington: “This is up to the utility but 20 years is the example offered. Plan recommends long-run and short-run components.”[128]
- Utah: “A 20-year planning horizon.”[129]
- Vermont: Survey report of 10 and 20 years planning horizons.[130, 131]
- Wyoming: Up to 15 years.[132]
- Bonneville Power Administration: Transmission planning horizon of 20 years.[133.]

- WREZ, in its Study Request to the WECC/TEPPC 2009 Work Plan, which was approved January 20, 2009, indicated that one of the issues that WREZ was interested in understanding was, “The transmission needed across the Western Interconnection to deliver power from preferred REZs to loads in a long-term time horizon (e.g., 20 years) assuming renewable energy rises to 33 percent of total generation.”

Longer than 10-Year Transmission Planning Horizon

The preceding list confirms the notion that a longer than 10-year planning horizon is not only feasible and possible, but also a perceived requisite in some regions.

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[126] State IRP Requirements and Issues. http://www.nwcouncil.org/energy/powersupply/adequacyforum/2003_0528/irprequirements.pdf

[127] State IRP Requirements and Issues. http://www.nwcouncil.org/energy/powersupply/adequacyforum/2003_0528/irprequirements.pdf

[128] State IRP Requirements and Issues. http://www.nwcouncil.org/energy/powersupply/adequacyforum/2003_0528/irprequirements.pdf

[129] State IRP Requirements and Issues. http://www.nwcouncil.org/energy/powersupply/adequacyforum/2003_0528/irprequirements.pdf

[130] Regulatory Assistance Project Electric Resource Long-range Planning Survey, State: Vermont, Survey Date: 8/11/05.

[131] Regulatory Assistance Project Electric Resource Long-range Planning Survey, Transmission and Distribution Planning Version, State: Vermont, Survey Date: 8/25/05.

[132] Regulatory Assistance Project Electric Resource Long-range Planning Survey, State: Wyoming, Survey Date: 9/09/03.

[133] Bonneville Power Administration, "Metrics for Financial Assessment of Infrastructure Needs", Transmission Regional Dialogue Issues Team, April 7, 2008.

The key points made by advocates of longer transmission planning horizons include:

- Transmission planning, siting, and construction lead times are typically longer than generation construction lead times. For instance, for major transmission projects, permitting, acquisition of rights-of-way, and construction may exceed 7 years or more, but generation lead times are usually shorter (except for perhaps nuclear power plants). Typical lead times are, 1 to 1.5 years for peaking gas turbines, 2 years for combined cycle plants, and 4 to 4.5 years for coal plants. Some renewable resources could take a much shorter time.[134]
- Deferring backbone transmission upgrades until new generation is committed is risky: new generation capacity additions are timed to coincide with load requirements and many state and regional rules discourage construction of "excess" capacity, especially by small entities. Longer transmission planning horizons enable right-sizing of the transmission projects to meet the longer-term requirements that have to be considered in a few years time anyway.
- A longer planning horizon allows identification of future potential transmission corridors far in advance of actual need, and thus, provides ample opportunity to prepare and address local permitting and right-of-way issues with the early involvement of affected land owners and local authorities.

  Given the continuous changing landscape of the electric power sector in the US driven by climate change and clean energy concerns and regulations, the eventual higher load growth, and proliferation of renewable energy resources, it is reasonable to take into account the generation and load outlook beyond the traditional 10-year planning horizon. The increased uncertainty in the outlooks beyond a 10-year planning horizon can be dealt with by doing additional planning scenarios based on the variants of the main drivers. Otherwise, with future being a moving target, chances of missing the target, in this case, not building the right transmission infrastructure, or building an undersized transmission project due to a short-sighted outlook, is more than a distinct possibility.

9.6.3 Appropriate Roles for Planning Entities

As discussed earlier, the current regional coordination and collaboration is restricted in its geographic reach. The transmission planning studies appear ad hoc and disjointed in nature without an overarching regional transmission plan.

WestConnect is performing the role of overall coordinator among its sub-regional planning groups. A more appropriate role of WestConnect may be to actually perform an annual long range transmission expansion planning study, both economic- and reliability-based. The studies should be regional in their extent, with the sub-regional planning groups, such as CCPG, providing the necessary liaison to the utilities in their footprints and be a clearinghouse for the underlying data and information used in the

[134] "Transmission Planning Putting the Horse Before the Cart", Robert A. O'Neil, Regional State Committee Meeting, Kansas City, July 23, 2007. http://www.spp.org/publications/RSC%20Presentaiton%20-%20Long%20Term%20Planning-FIN.pdf

regional planning studies. An ideal prospect is for WestConnect to evolve into a fully functioning RTO, with the full range of functions and services that are performed and provided by today's various RTOs in the US, from regional transmission expansion planning, to addressing region-wide interconnection issues, and the need for simplified regional transmission wheeling rates.

The WECC's Transmission Expansion Policy and Planning Committee would ideally provide the proper forum for the Western Interconnect-wide planning studies that would encompass the whole of WECC's footprint. This would be similar to the Eastern Interconnect-wide planning effort underway.

9.6.4 Improved Coordination with Generation Planning

Federal Legislation is being considered that would open up the planning process to regional transmission organizations and utilities that successfully initiate an interconnection-wide planning process. The proposed bill directs FERC to coordinate the assortment of regional planning efforts that have emerged in the east and west to agree on interconnection-wide plans. Federal regulators would then defer to a planning entity that emerges out of that process.

As discussed elsewhere in this report, improved coordination of transmission and generation planning is more of a technical issue than a regulatory issue. The current traditional reliability-based transmission planning includes projection of future generation in a sufficient amount to satisfy future load and installed reserve requirements at selected hourly snapshots (peak hour conditions at certain years) in the future. The underlying analysis is based on the notion that a transmission system that is planned and developed would meet all the reliability and stability requirements.

As described elsewhere in this report, an economic-based planning approach will, in addition to the traditional reliability analysis, include economic considerations, ideally with internalizing externalities, such as environmental- and greenhouse gas-related costs, and which would consider future generation and transmission options together. The methodology for such an integrated analysis is not fully developed yet. However, such studies can be carried out using iterative methods of combining integrated resource planning with security-constrained economic dispatch and a finite number of transmission development options.

9.6.5 Expand Oversight of Transmission Planning

Currently, all Colorado transmission providers are involved, to various degrees, in regional transmission planning venues, including CLRTP, CCPG, and WestConnect. However, the process reflects, at best, varying degrees of coordination and collaboration. The planning studies are on an ad hoc basis looking at various transmission proposals in the context of developing the infrastructure subject to meeting future load and reserves and satisfying the mandated reliability and stability requirements. What is needed is a more cohesive process with an extended oversight of the planning process to ensure that the planning process addresses not only the reliability needs but also economic and environmental needs at the regional level.

The FERC 890 and SB 100 processes have limited jurisdiction in terms of the transmission planning oversight afforded to the FERC and the PUC, and in fact, in terms of coverage, applies to IOUs with other transmission providers engaging on a voluntary basis. There is additional oversight at the PUC through the CPCN process, which is more in the context of individual transmission projects. To extend the oversight of transmission planning processes to all of the transmission-owning entities, will most likely, require legislative action at either the federal or state level, which may prove a daunting task in view of the jurisdictional fragmentation of the transmission system and the varied interests that represent them.

Another option is to encourage the evolution of WestConnect into a fully functioning RTO, which entails oversight of transmission planning at the regional level. This is a line of action that requires cooperation and coordination of state governments and state PUCs at a regional level.

Both options require strong political leadership at state and regional levels to have any chance of success.

9.7 Transmission Planning with Generation Planning

9.7.1 Transmission Planning: Reliability vs. Economics

Traditional transmission planning is concerned with reliability as the foremost attribute for consideration and with only secondary consideration to the overall system-wide economic impacts (cost and benefit) of the transmission development.

Traditional transmission planning involves application of power flow studies and stability analysis looking at snap-shots of time, such as peak conditions in a future year, with assumptions on load and resources representative of that particular juncture in time. These studies also include a number of scenarios as variants from the base case assumptions on the principal drivers. As an example, a scenario may include assumptions on additional generation resources in a particular area.

The overall objective of traditional transmission planning is to study the transmission needs sized to meet well-defined reliability requirements under the future conditions while ensuring availability of sufficient capacity to meet the energy needs of native electricity customers.

However, a broader view is emerging that long-range transmission expansion planning should consider other attributes beyond reliability, such as the broader economic and environmental impacts.

For instance, traditional reliability-based transmission planning would meet the target requirements for reliability and also for providing the necessary carrying capacity to allow access for the energy from planned generation to reach its destination market. A transmission upgrade based on traditional planning criteria would, by definition, prevent a future congestion, since in its absence, the needed electric energy would not reach its growing customer base due to lack of needed transmission.

However, such a transmission upgrade would have far-reaching economic impacts on other parts of the interconnected transmission grid, simply because electric power flows in the transmission system follow certain physical laws that cause the power to flow along the path of least resistance. Hence, a transmission upgrade in one region may result in either relieving or exacerbating transmission congestion in some other regions on the grid. Congestion usually results in either the creation of higher-priced load pockets, where the needed less expensive generation cannot reach the load, thus resulting in utilization of a more expensive generation; or lower-priced supply pockets, where there is an over-supply of less expensive generation that cannot get out.

Hence, a transmission upgrade can have varying degrees of impact on generation and flow patterns resulting in higher or lower costs at various points on the transmission grid. In economic terms, this translates into changes, positive or negative, in "consumer surplus" and "producer surplus," due to impacting the underlying system generation costs and the resulting electricity prices. In other words, a transmission upgrade may result in a variety of economic winners or losers beyond its immediate service territory. In fact, in markets based on nodal pricing (i.e., pricing that is reflective of the actual cost of service by location and time), there is an immediate impact on locational generation prices and zonal consumer prices. A transmission upgrade may impact different regions differently.

Current traditional transmission planning is not equipped to account for these economic impact evaluations. The kind of analysis carried out within WestConnect, or more precisely, by the sub-regional groups such as CCPG, do not account for such economic impacts that need to be evaluated through all hours of a planning horizon, since the traditional transmission planning is concerned only with reliability impacts in one or a few snap-shots in time.

The exception in the region is the sort of analysis that is carried out by WECC's TEPPC, since the TEPPC analysis appears to be based on a chronological security constrained economic dispatch analysis using PROMOD™, a production costing software (both zonal and nodal) provided by Ventyx.[135] Such an analysis, attempts to model optimal dispatch of generation with consideration of transmission topology and respecting generation- and transmission-specific constraints on an hour-by-hour basis, with the objective of keeping total system costs at a minimum. Such an analysis provides for determination of resulting local or regional or system-wide costs and benefits.

Combining such an analysis with various transmission scenarios in an iterative manner with power flow analysis at selected junctures in time, would result in selection of transmission expansion plans that not only meet the reliability requirements, but also result in the least cost and highest benefit on a system-wide basis.

[135] http://www.ventyx.com/analytics/promod.asp

9.7.2 Theoretical Underpinnings

The approaches for transmission planning for reliability versus economic considerations are quite different. However, a reliability-based analysis would always be required. Hence, an economic analysis would be a complement, rather than a replacement, to a reliability-based analysis. The following is a cursory summary of the different approaches (not meant to provide full coverage of all possible methodologies):

- Transmission Planning for Reliability: Power flow and stability studies, to investigate transmission adequacy subject to meeting established reliability requirements in a target hour in the future subject to given future load and supply assumptions.
- Transmission Planning for Economics: Integrated generation and transmission resource planning:
  - An integrated generation and transmission expansion planning, combining multiple transmission scenarios with model runs of a generation expansion model, together with a chronological security constrained economic dispatch analysis, under various transmission upgrades or expansion scenarios, in order to investigate the local, regional, and total system costs and benefits of various options.
  - A complex unified "dynamic programming" approach that considers various sets of generation and transmission build decisions at various stages of time, in order to find the optimal regional policy for future additions of transmission and generation.

A practical optimal generation and transmission expansion planning model would be a very complex and cumbersome model in terms of data requirements, optimization routines, number of operations, and the calculation times. Such a complex model is yet to be developed.

Instead, what is possible is the iterative approach of running a generation expansion model together with a chronological SCED analysis for a limited number of transmission scenarios. As noted, such a study should still include a complementary reliability analysis.

10.1 Desirable RTO-like Features

Although Colorado does not belong to an RTO or an ISO, there are RTO-like features that would be desirable in Colorado and other Western markets.

10.1.1 Regional Transmission Organization and Independent System Operator Definitions

An ISO is a non-profit organization that is responsible for operating the power systems of all the transmission and generation entities in its service territories that may include a multitude of utilities and cover many states. The ISO treats the combined transmission system of its members as a single system and is independent of the transmission owners and the customers that use its system. ISOs operate non-discriminatory competitive day-ahead and real-time markets for energy; and in most cases, they also operate markets for capacity and ancillary services as well. ISOs also provide congestion management services either through pricing or other transmission load-relief mechanisms. Most ISOs are either operating or planning to operate some form of nodal markets, i.e., markets based on locational marginal pricing where prices vary with both location and time, and are determined for each node (transmission bus) on the system. Hourly locational prices typically consist of energy, congestion, and transmission loss components.

In contrast, a RTO does not operate markets. Instead, it is primarily concerned with provision of open and non-discriminatory access to transmission and also with long-range transmission expansion planning and ensuring reliable operation of the transmission system under its jurisdiction. RTOs generally offer regional wholesale electric transmission services under one tariff.

FERC first required transmission owners to provide non-discriminatory access to their lines in Order Nos. 888 and 889, building on the model it had used to require interstate natural gas pipelines to provide access to pipeline capacity. In those orders, FERC noted that ISOs could provide the additional assurance of independence from the owners and the elimination of multiple pancaked rates to transmit electricity over long distances. Shortly thereafter, FERC Order No. 2000 encouraged the formation of RTOs to regionally manage portions of the US' electricity grid.

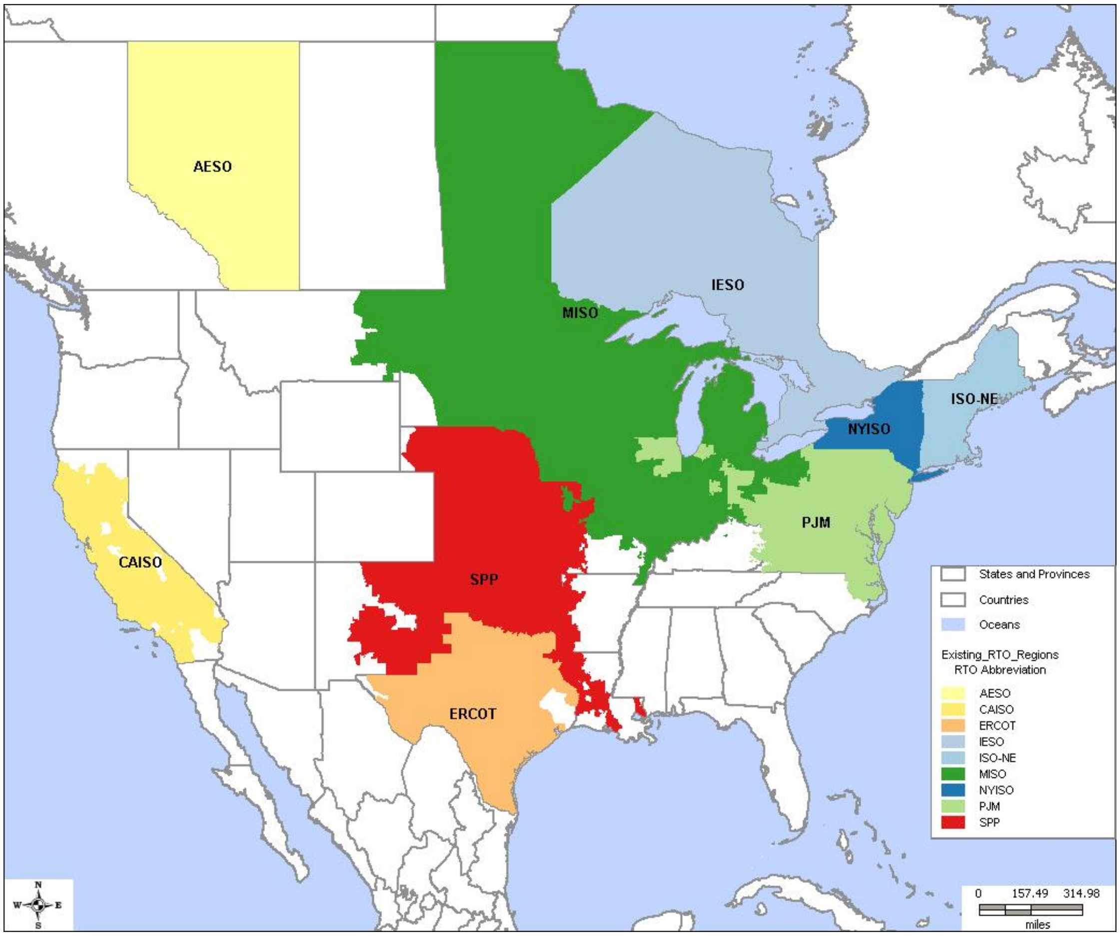
RTOs and ISOs were created by regional stakeholders in response to FERC's Orders 2000 and 888, respectively to:

- Facilitate competition among wholesale suppliers.

- Provide non-discriminatory access to transmission by scheduling and monitoring the use of transmission.
- Perform planning and operations of the grid to ensure reliability.
- Manage the interconnection of new generation.
- Oversee competitive energy markets to guard against market power and manipulation.
- Provide greater transparency of transactions on the system.
- Some are confined to a single state (ISO); some cross multiple states (RTO) (terms often used interchangeably).
- Manage congestion.
- Perform long-range transmission planning on a region-wide basis.
- Provide a single postage stamp rate across its territory, with a streamlined mechanism for cost allocation and recovery and distribution among transmission owners.

Figure 10-1 depicts the geographic extent of the current RTOs in the US. Presently, all current RTOs also happen to be ISOs.

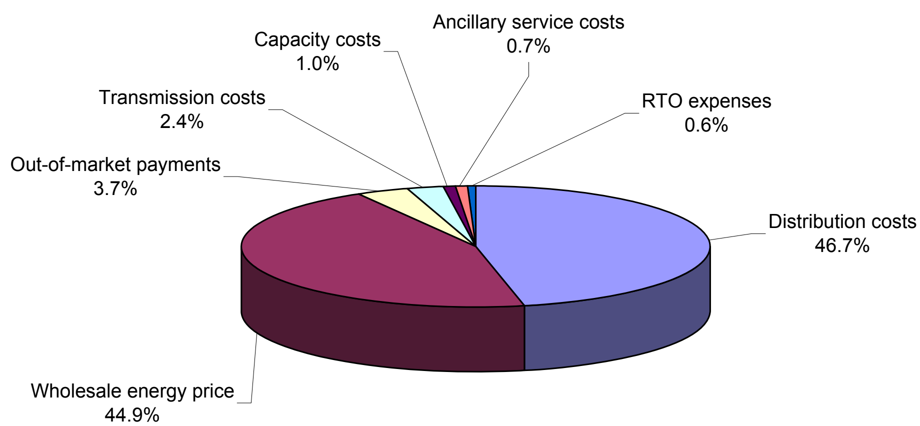
Figure 10-1. Independent System Operators in North America



10.1.2 Regional Transmission Organization Costs

A major argument against establishment of an RTO in a region concerns the underlying costs of RTO development. To get a sense of costs related to an RTO's operation, Figure 10-2 presents a typical customer's electricity cost components in New England. It should be noted that ISO-NE, in addition to being an ISO, is also an RTO.

Figure 10-2. Cost Components of a Typical New England Customer



Source: "Electricity Restructuring: FERC Could Take Additional Steps to Analyze Regional Transmission Organizations' Benefits and Performance," GAO Report No. GAO-08-987, Government Accountability Office, September 2008.

As can be seen, the transmission costs for a typical New England customer constitutes only two percent of the total electricity costs. There are additional transmission congestion-related costs that are reflected in the wholesale energy prices (i.e., the congestion component). The RTO expenses are less than 1 percent of the total electricity costs. Compared to energy- and distribution-related costs, the transmission- and RTO-related expenses are rather insignificant.

As shown in Table 10-1, rates charged to RTO market participants between 2002 and 2006 were lowest at the MISO, SPP, and PJM compared to the rates at the CAISO, ISO-NE, NY ISO, and PJM. Interestingly enough, the ones with lower rates are the ones with traditionally lower cost coal-fired baseload generation. PJM straddles the Midwest and hence, is also well endowed with low cost coal-fired baseload generation, particularly in its western territories. One may argue that the higher cost RTOs are the ones with historically higher cost electricity.

Table 10-1. Inflation-Adjusted Rates Charged to RTO Market Participants

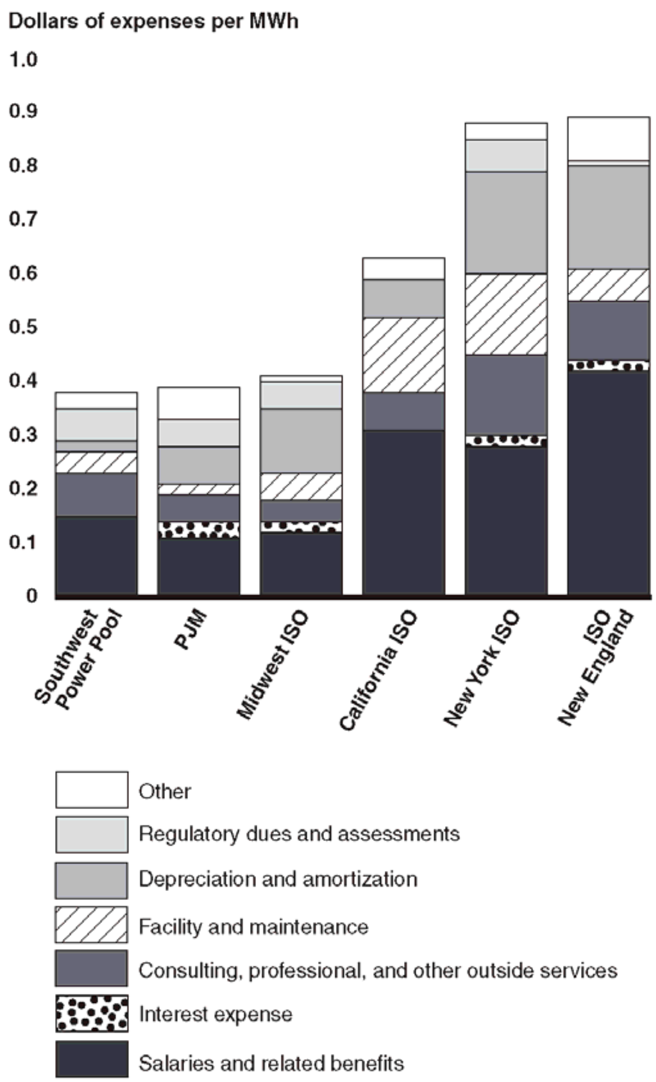
	2002	2003	2004	2005	2006
California ISO	$1.15	$1.17	$1.06	$0.95	$0.79
ISO New England	$0.55	$0.94	$1.01	$0.89	$0.84
Midwest ISO	$0.23	$0.18	$0.25	$0.39	$0.39
New York ISO	$0.77	$0.82	$0.84	$0.84	$0.82
PJM	$0.51	$0.57	$0.49	$0.38	$0.39
Southwest Power Pool	$0.23	$0.21	$0.16	$0.17	$0.16

Source: "Electricity Restructuring: FERC Could Take Additional Steps to Analyze Regional Transmission Organizations' Benefits and Performance," GAO Report No. GAO-08-987, Government Accountability Office, September 2008.

Note: Rates adjusted for inflation and presented in 2007 dollars.

In Figure 10-3, it can be observed that the expenses, on a per MWh basis, are also lower for MISO, SPP, and PJM, compared to CAISO, New York independent system operator, and ISO-NE.

Figure 10-3. Inflation-Adjusted Expenses per MWh by RTO, 2006

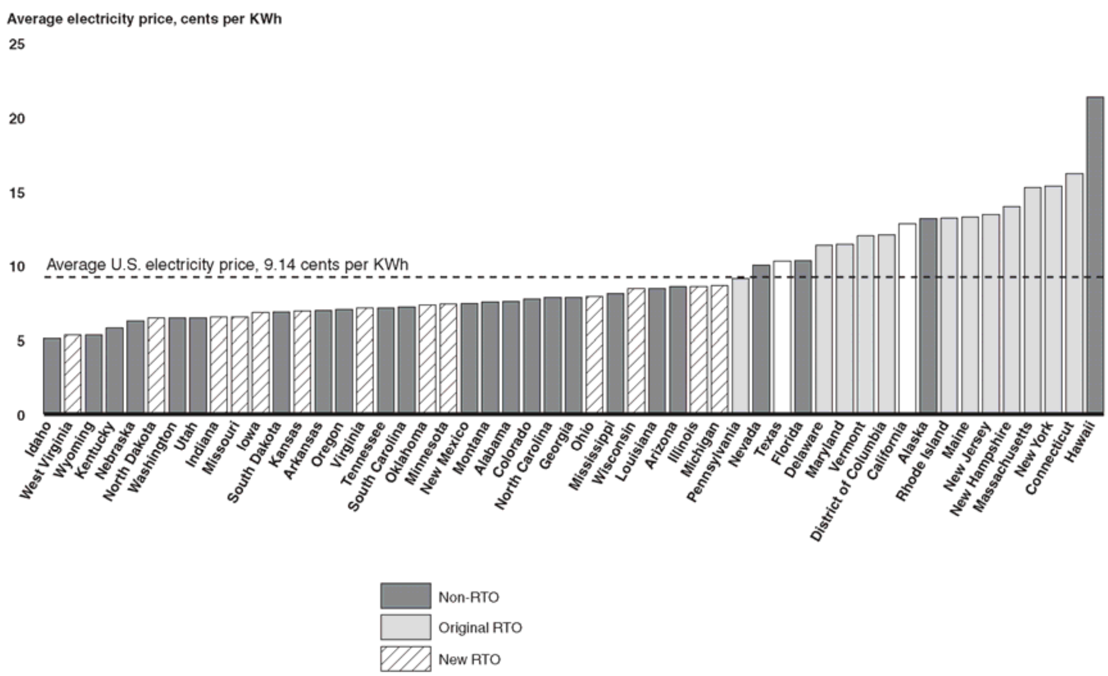


Source: "Electricity Restructuring: FERC Could Take Additional Steps to Analyze Regional Transmission Organizations' Benefits and Performance," GAO Report No. GAO-08-987, Government Accountability Office, September 2008.

Note: GAO analysis of RTO independent auditor reports from 2006. Dollar amounts are inflation-adjusted and presented in 2007 dollars.

Figure 10-4 compares the retail electricity prices at regions under the original RTOs, new RTOs, and non-RTOs. It can be observed that retail electricity prices are generally higher at the original RTOs. Prices are relatively lower at new RTO and non-RTO regions. However, it must be noted that the original RTO regions have historically been high-priced areas even before the advent of the RTO or ISO in their regions. New RTO regions are generally regions with plenty of low cost coal-fired baseload generation. The question is whether higher prices in the original RTO regions are caused by the underlying costs and structure of RTOs or whether they are a reflection of historically higher cost generation in those regions.

Figure 10-4. Retail Electricity Prices by State, 2007

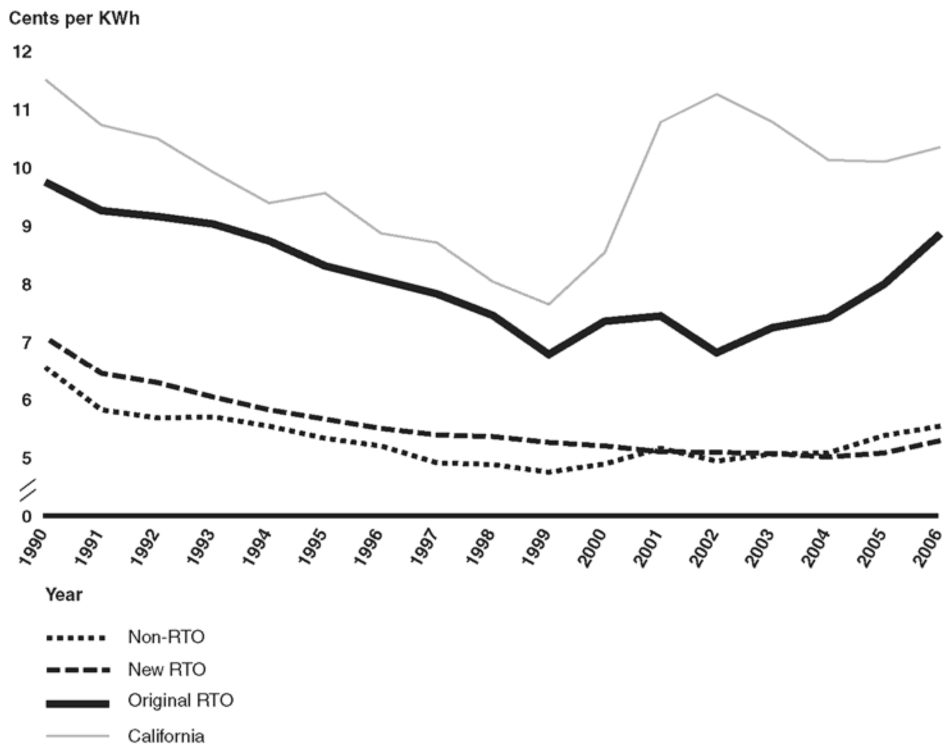


Source: "Electricity Restructuring: FERC Could Take Additional Steps to Analyze Regional Transmission Organizations' Benefits and Performance," GAO Report No. GAO-08-987, Government Accountability Office, September 2008.

Note: GAO analysis of EIA data on estimated 2007 retail rates. Information for California is presented separately from the three primary groups in the legend. Information on Texas is presented for purposes of comparison, although the wholesale market in most of Texas is not regulated by FERC.

Figure 10-5 also shows that electricity prices are generally lower for new RTO and non-RTO regions compared to the original RTO regions. Again, the fact that new RTO regions are performing as well as non-RTO regions indicates that having an RTO is not necessarily correlated with higher prices. The higher prices may be due to the historical higher cost generation in the original RTOs.

Figure 10-5. Inflation-Adjusted Retail Electricity Prices for Industrial Consumers, 1990-2006



Source: "Electricity Restructuring: FERC Could Take Additional Steps to Analyze Regional Transmission Organizations' Benefits and Performance," GAO Report No. GAO-08-987, Government Accountability Office, September 2008.

Note: At the time of GAO's review, the annual data series from Energy Information Administration used for this figure did not include 2007 estimates.

10.1.3 Findings of the Government Accounting Office on Electricity Restructuring

Regardless of the anecdotal evidence presented, the question of whether RTOs or ISOs contribute to higher costs has not been fully settled. A study by the Government Accounting Office made the following observations:[136]

- Experts, industry participants, and FERC lack consensus on the benefits of RTOs.
- Many agree that RTOs can improve management of the transmission grid and access.
- Many agree that RTOs provide opportunities to lower costs of producing electricity, but some question whether this improves consumer prices.
- Experts and industry participants are divided on the benefits of RTOs' markets and their effect on consumer electricity prices, generator efficiency, and infrastructure investment.
- Experts and industry participants are divided on RTOs' influence on electricity prices.
- The original RTO region tends to rely more heavily on natural gas than the non-RTO region.
- Experts and industry participants disagree on RTOs' influence on generator plant efficiency.
- Experts and industry participants disagree about RTO influence on infrastructure investment.
- Studies of restructuring and RTOs draw differing conclusions.
- RTO-developed assessments of performance find benefits.
- FERC believes RTOs have produced benefits but has not conducted a study or developed a comprehensive set of publicly available measures for tracking RTO performance.

However, the Government Accounting Office reports that FERC believes RTOs have produced numerous benefits, including the following:

- Improving the efficiency of the regional transmission grid, including resolving operating problems such as transmission congestion, providing more efficient transmission pricing policies, and minimizing market power.
- Improving transmission reliability by facilitating more accurate calculations of regional transmission capacity.

[136]GEO Report on Electricity Restructuring, September 2008. http://www.nreca.org/Documents/PublicPolicy/GAOreport.pdf

- Improving access to the grid by reducing opportunities for discriminatory transmission practices.
- Improving competition in regional power markets by facilitating the entry of new independent generators
- Facilitating stakeholder consensus solutions to regional problems.
- Enhancing transparency and oversight regarding how prices are determined and how access to the grid is granted.
- Providing a process of regional transmission planning, thus resulting in more efficient planning and use of resources across a region, as well as an opportunity for input by a broad range of stakeholders.

According to GAO, FERC has not conducted an empirical analysis to measure whether RTOs have achieved these expected benefits or how RTOs or restructuring efforts more generally have affected consumer electricity prices, costs of production, or infrastructure investment.

According to GAO, as a way of addressing concerns about whether they have provided benefits, some RTOs have quantified the benefits they believe they have provided to their regions. ISO-NE, for example, developed measures related to wholesale electricity prices, power production costs, emissions, and other areas to quantify the value it has provided to New England. According to ISO-NE, average wholesale electricity prices in its region, when adjusted for rising fuel costs, have declined from $45.95 per MWh in 2000 to $42.64 per MWh in 2006. ISO-NE reports that over this same period, non-fuel-adjusted prices rose from $45.95 per MWh to $62.74 per MWh. MISO also recently developed an initiative to quantify its performance. According to its analysis, MISO has improved electric service reliability and is more efficiently using generation resources, a fact that, along with others, has contributed to between $555 and $850 million in annual net benefits.

10.2 Benefits of Having an Regional Transmission Organization or Independent System Operator

There are significant costs associated with the development and implementation of an RTO and/or ISO structure in any region. However, a distinction should be made between an RTO and an ISO in terms of their functions, authorities, requirements, and market-changing impacts. Creation of an RTO without ISO functionality is a less daunting task than developing an ISO market structure.

Developing an RTO is not the same as developing an ISO. Development of an ISO requires implementation of market bidding, dispatch control, and transaction settlement systems, since ISOs are mainly concerned with optimal and non-discriminatory allocation of generation resources in a competitive environment. Development and implementation of an ISO, particularly in the case of nodal markets, is a rather onerous undertaking. In contrast, RTOs are mainly concerned with transmission, and do not necessarily require a centralized market mechanism or dispatch control and settlement systems. What they require is a change in adoption of a new paradigm in transmission ownership, control, and service. In other words, development of RTOs is more a matter of organizational change, whereas ISOs further require construction of a technological overlay.

In summary, the benefits of RTOs are generally believed to include the following:

- Region-wide long-term transmission expansion planning.
- Improved efficiencies in the management of the transmission grid.
- Improved grid reliability.
- Removal of opportunities for discriminatory transmission practices.
- Improved market performance.
- Facilitation of lighter-handed government regulation.
- Elimination of pancaked rates.
- Meeting operating reserve requirements more efficiently.
- Better maintenance coordination (generation and transmission).
- Fuller utilization of existing transmission capacity.
- Improved congestion management.
- Transmission planning based on regional outlook.
- Enhanced market monitoring.
- Prospects for more transparency in prices.
- Ease of entry for newcomers.
- More level-playing field for merchant operators.
- Region-wide mechanisms for integration of renewable resources.
- Market diversity.
- Region-wide demand response integration.

10.2.1 RTO-Like Features Appropriate for the Region

Implementation of an ISO market structure is a major and costly undertaking requiring a fundamental restructuring of the traditional bilateral markets, and hence, the reason they are mostly developed in regions which already had a market pool structure with economy interchange and reserve sharing agreements. Imposing an ISO structure in traditional bilateral markets requires a revolutionary transformation on how the markets are run, with significant reduction in the traditional control, power, and independence of the franchised, vertically integrated natural monopolies.

However, creation of RTOs, combined with a wider virtual control area, without the centralized day-ahead and real-time market structure, is a less daunting task, albeit still not an easy undertaking, particularly with regard to development of a region-wide postage stamp or license plate transmission tariff. As a starting point, there are a number of beneficial features of RTOs that can be handpicked and selectively applied, in a piecemeal basis, to bilateral markets such as RMPA or the WestConnect territory. The challenge is the development of organizations and/or mechanisms that would produce similar results in these markets without a major overhaul that accompanies a full-featured RTO development.

All of the RTO benefits listed above are desirable features that would elevate the quality of the electric power system in the state and the region and address many of the outstanding issues that have been identified by various stakeholders.

The most important features include:

- A regional authority to oversee region-wide long-range transmission expansion planning.
- A virtual control area encompassing multiple balancing areas that would achieve a higher level of efficiency in terms of utilization of energy and reserve resources.
- A more simplified transmission rate structure that would eliminate rate pancaking.
- A more level playing field for entry and engagement of independent and merchant entities.

As noted, there are major obstacles to implementing these features at the state and/or regional level. These obstacles are mainly the result of the jurisdictional fragmentation of the market in the state and the region. Hence, adopting any of the RTO-like features would still require a higher level of cooperation and collaboration at the regional level, necessitating a degree of encouragement by state governments and their policy makers. The development of a higher regional authority with RTO-like features can be achieved by the regional political forces (i.e., WGA, state governments, and PUCs) promoting elevation and/or evolution of the WestConnect to an RTO-like entity. The question is how to align the interests of various stakeholders to make this a possibility. Hence, the need for various legislative, regulatory, and policy incentives and leverages that would shepherd the movement of the market and the stakeholders towards that end.

10.3 Job Implications of Building New Transmission

It is expected that investment in transmission development that would allow renewable energy resources like wind, solar, and geothermal energy to have access to their intended markets would produce considerable economic and environmental benefits.

The economic benefits of transmission development include creation of temporary and permanent jobs in construction, manufacturing, and operations. The following examples, based on studies of planned transmission development in the US, illustrate the potential for job creation resulting from investments in the transmission grid.

10.3.1 Southwest Power Transmission Study

The consulting firm of CRA International performed an analysis on a planned 1,200-mile, 765-kV transmission project located in Texas, Oklahoma, and Kansas. The project's two first proposed loops of the SPP EHV Overlay, including the Prairie Wind and Tall Grass Transmission projects ("Two Loop project"). The study, performed on behalf of Electric Transmission America, OGE Energy Corporation, and Westar Energy, found that the project would yield "substantial net benefits" to the Southwest Power Pool.[137] These benefits include:

- The creation of 14,075 MW of wind energy throughout Kansas, Texas, Oklahoma, Missouri, and New Mexico.
- The creation of more than 10,000 jobs during construction: 2,497 in Texas, 4,131 in Kansas, 3,247 in Oklahoma, and 351 in New Mexico.
- The creation of approximately 5,500 jobs during operations: 1,654 in Texas, 1,955 in Kansas, 1,610 in Oklahoma ,and 351 in New Mexico.
- The annual addition of $60 million in property taxes and $500 million in economic output.
- The annual avoided emission of nearly 30 million tons of carbon dioxide.
- The annual net power supply benefit of $2.8 billion (in 2008 dollars).

Additional benefits included:

- An additional $100 million benefit in reduced power losses in SPP.
- More than 20 percent of SPP demand supplied by renewable energy.

Overall project costs included:

- Cost of the EHV Overlay facilities needed to complete the Two Loop project: $400 to $500 million per year.
- New wind costs: $1.75 billion per year net of production tax credit.

CRA concluded that the Two Loop project yields substantial net benefits to SPP.

10.3.2 Arrowhead-Weston Benefits Report

In February 2009, the American Transmission Company announced the completion of its 220-mile, 345-kV Arrowhead-Weston transmission line project that runs from Minnesota to Wisconsin and has a carrying capacity of 600 MW. The benefits of the project, which cost $436 million, in addition to increased access to renewable energy resources, include.[138]

- 2,560 jobs generated or supported.

[137] CRA International , "First Two Loops of SPP EHV Overlay Transmission Expansion, Analysis of Benefits and Costs", September 26, 2008, http://www.crai.com/uploadedFiles/RELATING_MATERIALS/Publications/BC/Energy_and_Environment/files/Southwest%20Power%20Pool%20Extra-High-Voltage%20Transmission%20Study.pdf

[138] American Transmission Company, "Arrowhead-Weston Transmission Line Benefits Report", February 2009, http://www.atcllc.com/documents/AW_FINAL.pdf

- 5.3 million tons of carbon dioxide emissions avoided.
- $9.5 million in tax revenue generated.
- $464 million in total economic impact.
- $94 million in savings over 40 year.
- 35 Megawatts saved in reduced energy losses.

Overall, the project is expected to return $1.45 for each dollar spent on the project.