Governor's Energy Office

RECHARGE COLORADO

STAR

Strategic Transmission and Renewables

A Vision of Colorado's Electric Power Sector to the Year 2050

A Report of the Colorado Governor's Energy Office

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Photo by Matt McClain

Letter from the Director

The STAR report is the fourth installment in a series of reports released by the Governor's Energy Office to prepare Colorado for a changing energy landscape.

Colorado's leadership in developing a New Energy Economy is structured around the anticipation of ways in which future generations will produce and consume energy. It is likely that the generation resources of this energy future will emit far fewer pollutants than we have historically. Renewable energy along with other low emitting resources is likely to play an increasing role in meeting the energy demands of the future.

The STAR report picks up where the REDI report left off. It further delves into the changing energy resource landscape, updating projections to reflect recent legislative changes that dramatically reduce generation from coal resources and increase the components of our energy mix from renewable and natural gas resources to reflect current law.

The report provides a detailed analysis of ways in which Colorado's utilities can plan for both demand side and supply side resources and the transmission infrastructure necessary to deliver reliable electric power to a growing state. The future decisions of our state's utilities will have a very direct impact on the ability of the state to meet the critical targets of the Climate Action Plan to reduce our emissions of carbon dioxide to a level that will slow degradation of our natural environment. The objectives of the Climate Action Plan: 20% reduction in greenhouse gas emissions by 2020 and an 80% reduction by 2050 below 2005 levels are central to the STAR report.

With proper planning we can meet the power needs of the future while protecting Colorado's natural heritage for future generations. The STAR report offers an analysis our challenges and recommendations on ways in which we can achieve these important goals.

Tom Plant, Director
Colorado Governor's Energy Office

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Executive Summary: Key Messages for Decision-Makers

The STAR report contains information and recommendations to address a multitude of challenges facing Colorado's electricity sector. The report updates previous work produced by the Governor's Office and the Governor's Energy Office, offering analyses of current issues and recommendations for actions to meet the long-term interest of Colorado's citizens.

The report provides current data and insights for an expanded discussion regarding additional steps the state should take regarding electric power. Views are presented regarding the optimal mix of demand-side and supply-side resources for consideration as Colorado plans the electricity sector policy landscape out to the year 2050.

The challenges and opportunities place a spotlight on how Colorado can build on its leadership position in the electricity sector through strategic planning. Other states are going through this exercise, and Colorado will benefit by identifying continuous improvements in policies and practices aimed at meeting the needs of our fast-growing population in an environmentally responsible and economically sustainable way.

The report emphasizes the importance of constraining what would otherwise be a costly increase in load growth. The established method to constrain load growth is to expand demand-side policies in both scope and scale, including extending demand side policies to utilities that have not yet adopted binding goals for energy efficiency.

Transformation of the electricity sector will help Colorado in many ways, including meeting Colorado's Climate Action Plan's (CAP) goal of reducing the electricity sector's carbon dioxide emissions by 80% by 2050 from a 2005 base. The STAR project conducted modeling that led to a series of recommendations to expand the state's utility-scale renewable and transmission infrastructures, coupled with growth of natural gas-fired generation capacity. Cleaner power generation lies at the heart of achieving the economic and environmental goals that constitute an optimum transformation.

Strategic decisions need to be made by today's policy-makers to ensure Colorado is set on a glide path toward a cleaner, more efficient energy portfolio that will benefit generations of Coloradans to come.

Topics and Recommendations

Well-known historical drivers have determined the structure of today's electricity sector. Given advances in technology, markets, and public policy, a concentrated focus on new drivers and structures is needed. In so doing, the state can craft policies to ensure responsible actions are taken to design a sustained, orderly development of Colorado's electricity sector out to the year 2050.

In sixteen chapters, this report covers a wide array of subjects, resulting in a series of recommendations on how Colorado can create a productive, reliable electricity sector that is economically and environmentally sustainable. The STAR report offers the following insights and recommendations on a wide variety of topics that can help inform the dialogue.

Chapter 1 – Modeling Colorado's Electric Power Sector

The STAR project produced a 38-page detailed modeling of Colorado's electricity sector out to the year 2050. Assumptions for load growth, fuel prices, cost and operating characteristics of new generation, renewable energy penetration levels and environmental compliance used in the modeling are conservative, transparent and defensible. The results indicate a variety of pathways for state electricity sector policy-makers to consider. The driving research question modeled was how Colorado can meet the CAP goal of an 80% reduction in carbon dioxide emissions by 2050 from a 2005 base. As the model results indicate, it can be achieved: furthermore, doing so will yield multiple benefits.

Colorado's population of 5 million is expected to grow to 9 million by 2050. A growing population coupled with a return to average historic levels of economic growth results in an imperative that new electric power infrastructure be planned and developed.

The modeling results in the need for five key actions to secure Colorado's strategic electric power sector: more energy efficiency, more utility-scale renewable energy, more high-voltage transmission, less coal-fired generation, and more natural gas-fired generation.

- First and foremost, the modeling reveals how essential it is, from economic and environmental perspectives, to moderate the load growth (assumed to grow at 1.7 per cent per year to 2050).

- The model selected utility-scale renewable energy as the preferred supply-side resource on the basis of its ability to reduce air pollution, reduce water consumption, and on the basis of being the least cost long-run resource, in large part because renewable energy does not incur fuel costs. However, there are operational limits on the penetration of variable renewable resources, and the model constrained the selection of renewable energy to conform to those operational limitations.

- It is well-understood that substantial new high-voltage transmission infrastructure is a linchpin issue that needs to be addressed to enable Colorado to deliver the renewable energy to the markets. Transmission is an enabler that achieves a variety of economic objectives over a very long time period with comparatively minimal operation and maintenance expenses. As has been proven in Texas and elsewhere, the return on investment is fast, and transmission represents less than 10% of the customer's electric bill.

- The model analyzed Colorado's coal-fired generation fleet, and determined that if the CAP goals are to be met, coal units should be retired when they reach the age of 45. Should the units not be retired and replaced at age 45, Colorado's electricity sector will experience increasing operation and maintenance costs, and public health will be compromised.

- Of critical importance, the state must expand deployment of efficient natural gas-fired generation. The nation's natural gas supply has been expanded considerably in recent years, and price forecasts provide a greater confidence in price stability compared to the price volatility experienced over the past three decades. Gas-fired generation is particularly beneficial due to its unique ability to integrate variable renewable resources, while serving as a baseload resource. The model assumed that by 2017 research and development activities will result in commercially available natural gas advanced combined cycle plants with 90% carbon capture and sequestration. These plants were assumed to have a lower capacity cost and lower operating cost than new conventional coal-fired generating stations without carbon capture and sequestration.

Recommendations:

- Colorado's policy-makers should work to develop a future-oriented electricity sector policy landscape to leverage our state's strategic strengths (abundant renewables and natural gas) and to avoid our weaknesses (air and water constraints).

- Colorado policy-makers should review whether the "10% by 2020" renewable energy standard for rural electric associations and municipal utilities should be revised to match the state's "30% by 2020" standard for investor-owned utilities.

Chapter 2 - The Multiple Benefits of Demand-side Resources

Demand side resources include a broad array of techniques and technologies including utility-sponsored demand-side management, distributed generation, demand response, energy efficiency, and conservation. The STAR report provides detailed descriptions of the multiple benefits of these demand-side measures. Although a broad understanding exists that investments in demand side resources represent the most cost-effective approach to achieving strategic goals in the electricity sector, at present, Colorado's demand side resources policy framework only applies to investor owned utilities. The STAR modeling demonstrates that the existing scale of Colorado's demand side policy framework will achieve a disappointing reduction in carbon emissions, and current policies stop considerably short of achieving the economic and environmental benefits that energy efficiency can bring to the state.

Recommendations:

- Legislators should craft policy modifications to align all Colorado utilities' financial incentives with investments in demand side management.

- Legislators should increase demand side management targets enacted in HB07-1037.

Chapter 3 - Addressing Climate Change and Water Issues through Renewable Energy

Colorado's world-class intellectual resources are expected to serve the essential function of expanding policy-makers' insights and analysis regarding climate change and other environmental challenges. Talented individuals and institutions in Colorado are well-positioned to maintain the state as a recognized leader in addressing energy and environmental issues, in large part, by planning the transformation of the electricity sector. In addition, Coloradans have an increasing awareness of the energy/water nexus that needs to be addressed in this semi-arid and drought-prone state.

The rapid expansion of utility-scale renewable energy in Colorado should be supported until its integration limits are reached. The STAR report describes this growth and discusses the economic and employment benefits that are expected to result.

Citizens and policy-makers who actively work to protect and enhance Colorado's environment, including the need to clean our air, secure clean water, protect wildlife, are urged to turn increasing attention to improve the electricity sector.

Recommendations:

- Colorado should expand the dialogue among scientists and policy-makers to create a future-oriented electricity sector strategy that positions Colorado to address climate change, economic opportunity, water scarcity, and other issues.
- Leadership from universities, research laboratories, the legislature, and utilities should further define the human and capital investments needed to improve the environmental performance of Colorado's electricity sector.

Chapter 4 - Recent Colorado Legislative Actions

During the tenure of Governor Bill Ritter (2007-2011), 57 bills relating to clean energy were signed into law. Two new state laws are particularly important in reshaping the state's electric power future. In March 2010 the governor signed HB10-1001, the renewable energy standard (RES). The act requires Colorado's investor owned utilities reach a minimum of 30 percent renewable electricity by 2020. Colorado's new standard is the nation's second highest, and the highest in the Rocky Mountain West. The act also established a production requirement for distributed generation that will provide a major economic boost to Colorado's solar industry.

In April 2010 the governor signed HB10-1365, the Clean Air-Clean Jobs Act, into law. The legislature passed the act in anticipation of federal Clean Air Act regulations that will require improved environmental performance in the electricity sector, particularly in Colorado's northern Front Range, which is in noncompliance with ground-level ozone standards. The act requires a reduction in nitrogen oxide emissions of 70 percent to 80 percent by December 2017 from coal-fired generation plants operated by Colorado investor-owned utilities, principally Public Service Company of Colorado (PSCo). For PSCo, the act calls for retiring the lesser of 900 MW of coal-fired electric generating capacity, or 50 percent of the company's coal-based capacity, in addition to those plants that PSCo was already planning to retire before January 1, 2015. The Public Utilities Commission (PUC) held hearings and has issued a final order that meets the provisions of the law.

Recommendation:

- Colorado should fully explore retiring other coal-fired generating stations after considering their age, environmental performance, in comparison to the economic and environmental benefits of displacing the coal units with natural gas-fired generation and other low-emitting resources.

Chapter 5 - Colorado's Transmission Infrastructure

Colorado's high voltage transmission infrastructure (defined as 230 kV and 345 kV) was developed over the decades to meet load growth. That aging infrastructure is now in need of substantial expansion to meet the needs of a state with five million residents, and a projected growth in population to over 9 million in 2050. New lines are also needed to deliver large blocks of renewable energy to the markets.

Transmission is the vital link to connect generation to loads. Colorado is preparing for the necessary major expansion in this infrastructure to improve the environment, and to meet the economic needs of a growing population.

Public Service Company of Colorado is the largest transmission owner and operator in Colorado. The second largest transmission owner and operator is Tri-State Generation and Transmission Association, Inc., a wholesale electric power supplier owned by 44 electric cooperatives. Western Area Power Administration markets and delivers reliable, cost-based hydroelectric power and related services within a 15-state region of the central and western United States, including Colorado. These three entities, their regulators and governing boards, are positioned to affirmatively address the strategic opportunities; however, further policy support is required.

A series of studies over the past decade have concluded that Colorado's transmission infrastructure is congested and under-sized in voltage and capability. Policy-makers and utilities are responding with heightened attention to planning and permitting challenges that need resolution to deliver large blocks of renewable energy to load centers. Concrete and near-term actions are warranted to resolve these issues.

Recommendation:

- The state needs a continued flow of information and solid assurance that Colorado's utilities and regulators will strategically plan, permit, and build transmission infrastructure consistent with the need to deliver clean, reliable power to a growing population in a water-scarce state.

Chapter 6 - The Growing Importance of Natural Gas

Natural gas-fired generation has been a primary technology of choice by utilities across the country over the past several decades, and by every indication it will remain so. Like every energy source, natural gas has its environmental challenges. The natural gas industry has opportunities to address those environmental challenges while facilitating integration of renewable energy on to the grid.

With the technological advent of directional drilling and hydraulic fracturing, many credible sources consider the nation's shale gas reserves to be a 100 year domestic resource. Although uncertainties exist, this large national supply provides a growing confidence that electric utilities can increase their reliance on gas-fired generation to displace the aging fleet of coal-fired generation over the next twenty years, while increasing the integration of naturally variable renewable energy on to the grid.

Colorado is in the national spotlight for advancing the Clean Air-Clean Jobs Act policy framework that will replace old and inefficient coal-fired generation with natural gas plants. Residents throughout the state will be direct beneficiaries of cleaner air, reduced water borne pollutants, energy cost containment, economic development, the stabilization of carbon emissions, and less disruptive compliance with increasingly stringent federal pollution standards.

Recommendation:

- Colorado policy-makers should conduct a comprehensive benefit-cost analysis (including economic and environmental measurements) to review the age, performance, continuing operations and maintenance costs of the remaining coal-fired generation stations in the state. Such a review should include a determination of the opportunities for gas-fired generation and renewable energy (and the associated transmission and pipeline infrastructure requirements and policy guidance) to facilitate cleaner resources to replace retired coal-fired generation.

Chapter 7 - The Role of Balancing Authorities

Colorado can be viewed somewhat as an electric island that lacks sufficient transmission infrastructure to connect to adjacent markets. Because Colorado utilities are not part of a liquid electricity market characterized by a regional transmission organization or an independent system operator, the market is considerably different than the "organized" and central markets that serve the majority of U.S. electric customers. According to NREL and GE's May 2010 Western Wind and Solar Integration Study, better operation of the balancing authorities can achieve savings that reach into the billions of dollars through more effective integration of variable resources. Such mechanisms may include all or some aspects of dynamic scheduling, intra-balancing area scheduling at subhourly time steps, or other wide-area economic dispatch concepts that do not require actual physical balancing area consolidation.

Recommendation:

- To the extent possible, the Legislature and PUC should direct a move toward either physical or virtual consolidation of the state's two balancing authorities. Utilities should work with key stakeholders to identify policy changes and modifications in practice which should be initiated to ensure maximization of system benefits from such consolidation.

Chapter 8 - Cost Recovery and Cost Allocation Challenges

"Cost recovery" describes how utilities receive reimbursement for capital costs expended. Cost recovery for transmission investments is often contentious because the regulatory process traditionally has a tendency to limit cost recovery to investments in near-term infrastructure. This results in forgoing more beneficial, higher-voltage, long-term investments. Too often, lower-voltage transmission is being planned when higher-voltage lines are needed to fully develop our vast renewable resources. These higher-voltage lines are crucial to successful implementation of a strategic vision of Colorado's electricity sector to 2050 and beyond.

"Cost allocation" is a term used to describe how costs of a capital investment such as a transmission line will be allocated to entities that use the line or benefit from the line. Regulators are increasing their consideration of the cost allocation issues, and 2011 appears to be headed for an opportunity to address this particularly thorny issue.

Recommendation:

- Colorado policy-makers should encourage both the Federal Energy Regulatory Commission and the PUC to exercise their pivotal roles to minimize market uncertainties inhibiting the right-sizing of transmission lines directly traceable to cost allocation and cost recovery issues.

Chapter 9 - Federal Action and Inaction

The federal government is a critically important partner, setting rules and regulations that determine the economic and environmental performance of the electricity sector. Recent congressional efforts to address the need for a comprehensive approach to climate protection, energy independence, clean energy, and transmission development, have been either stopped or seriously compromised. While congressional progress has stalled, positive signals and developments have come from the Administration and the Federal Energy Regulatory Commission.

Many states, including Colorado, have stepped in to fill federal policy gaps by implementing their own environmental and energy policies. Although this provides greater clarity in a particular state, the interdependency of the electric markets among neighboring states means regional solutions cannot be predicated on assessing the aggregate collection of individual state actions. If, and when it comes, coordinated federal action could address the fragmentation and uncertainty that characterizes the nation's electricity sector.

Recommendations:

- Colorado executive and regulatory leadership should expand its existing interaction with the Western Governors' Association's (WGA) initiatives and other entities to ensure that federal executive, congressional, and agency leaders develop timely and effective state-federal policy frameworks to create a dynamic, clean, efficient, and renewable 21st century electricity sector.

- The return of a strong federal role in national transmission infrastructure development should be actively pursued by Colorado policy-makers. Transmission infrastructure investments have the opportunity to be substantially expanded if the Federal Energy Regulatory Commission pursues the cost allocation and renewable integration frameworks as articulated in their proposed rulemakings. State policy-makers are also encouraged to see what changes are required to ensure that the Western Area Power Administration expands strategic backbone transmission, or helps other utilities expand that backbone transmission.

Chapter 10 - Regional Planning Activities

In Colorado's region, two of the most important entities involved with regional planning are the WGA and the Western Electricity Coordinating Council (WECC). These organizations constitute the primary structures through which much of the transmission policy and technical coordination occurs. The WGA coordinates a wide variety of projects, focusing on issues related to the West. WECC is responsible for regional transmission planning, and the WGA conducts regional transmission planning policy and resource assessments in the Western Interconnection. The Regional Transmission Expansion Project (RTEP), funded by the Department of Energy, is a valuable undertaking expected to greatly improve the regional ability to plan for, and ultimately develop, new transmission.

Recommendation:

- Legislators and the PUC should fully engage in regional planning activities to ensure that the state benefits from economic development, energy, and environmental quality opportunities that are directly related to these activities.

Chapter 11 - The Feasibility of Exporting Colorado's Renewable Energy

Colorado is rich in utility-scale renewable resources- more than enough to meet its renewable energy standard. However, the state is transmission-constrained and geographically distant from large population centers that would, in concept, purchase Colorado's renewable energy exports. The largest potential markets for Colorado's renewable energy export sales are in Arizona, Nevada, and Southern California. These areas also have rich renewable resources and an equally strong interest in marketing their renewable energy. Although a conceptual export market opportunity may exist for Colorado to export its renewable resources, the target market states have a distinct advantage of being closer to the loads. A considerable amount of economic, land use and engineering analysis has been conducted by the High Plains Express and other entities to determine whether Colorado has an export opportunity. A key conclusion of this analysis is that high-voltage lines are needed, but they entail large capital outlays, and cost recovery and cost allocation issues constitute a risk that may not be taken absent improvements in state and federal policies.

Recommendation:

- Legislators and the PUC should maintain and strengthen their relationships with the High Plains Express, the CCPG, and other entities to represent Colorado's interest when analyzing opportunities for exporting Colorado's renewable energy.

Chapter 12 - Promising Transmission and Grid Technologies

A substantial range of transmission and grid technologies are ready for deployment and are becoming commercially available. The STAR report describes a host of technologies that are either available, or are on the near horizon. These technologies include a wide array of smart grid technologies, storage technologies, electric vehicles, more efficient conductors, synchrophasors, and more.

As a general matter, electric utilities may be fully aware of these technologies; however, the lack of financial and regulatory incentives may be delaying their timely deployment. If Colorado is slow to adopt these technologies, the delays may diminish opportunities for the state to leverage many benefits that result from first-hand operational experience.

Recommendations:

- Colorado utilities should work with interested stakeholders and report to the legislature and the PUC with recommendations for policy and practice changes that will ensure that Colorado benefits by a more rapid introduction of new transmission and grid technologies.
- The Colorado General Assembly should carefully review the policy recommendations and roadmap for Smart Grid deployment contained in the 2011 Colorado Smart Grid Task Force Report.

Chapter 13 - Transmission Planning in Colorado

Responsibility for much of Colorado's transmission planning takes place under the auspices of the Colorado Coordinated Planning Group (CCPG)- a voluntary, joint, high-voltage transmission system planning forum operating within the WestConnect (southwestern states) footprint. CCPG and its subcommittees represent an effort primarily by utilities, and to a lesser degree by stakeholders, to move Colorado in the direction of unified transmission planning with a goal of single-system planning. Closer coordination between CCPG, key stakeholders, and the PUC is being explored as a central feature of a new commission rulemaking proceeding. Although transmission planning progress is moving forward, a greater sense of strategic purpose is needed to advance the state's electric power sector.

Recommendation:

- The PUC's rulemaking on comprehensive transmission planning needs to ensure that Colorado policy-makers are certain that anticipated reforms will establish a context and planning landscape from which the commission can judge whether utilities' applications for certificates of public convenience and necessity are consistent with a strategic plan, and are in the broad public interest.

Chapter 14 - Integrating Renewable Energy into the Grid

As renewable energy provides higher percentages of a utility's generation portfolio, grid stability will be managed in new ways. Innovative techniques are being explored to maintain or enhance reliability while integrating larger amounts of renewable energy. Solutions are being tested across the United States following many years of improvements in Europe, with successful results that provide opportunities for increasing renewable resources in the coming years. Recent analyses demonstrate that it is operationally feasible to achieve a penetration of 35 percent renewables, provided that important changes are instituted to current operating procedures, including balancing authority reform, and deploying more storage and communications intelligence on the grid.

Recommendation:

- Colorado transmission-owning utilities should expand their interaction with regional and national stakeholders regarding adoption of new methods to integrate renewable energy, and report their findings to the legislature and the PUC.

Chapter 15 - Transmission Permitting Challenges

Many view transmission siting and permitting issues to be a more difficult challenge than transmission planning and financing. A growing understanding exists that Colorado's permitting system may need to be more streamlined and better coordinated. Transmission siting and permitting must balance many interests, including concerns of property owners, environmental constraints, and local governments. Concerns from these constituents need to be addressed early in the transmission development process to mitigate chances for costly delays at the end of the process. Colorado has already experienced protracted litigation which has stymied expansion of the state's high-voltage transmission infrastructure and delayed transformation of the electricity sector.

Recommendation:

- Colorado policy-makers should consider whether the current legal structure for permitting transmission places the state at risk of slowing the transition to clean energy resources. If a substantial risk is determined, appropriate legislative solutions should be crafted.

Chapter 16 - The Potential for Independent Transmission Companies

Historically, virtually all high-voltage transmission built in the United States was planned, financed, designed, and constructed by electric utilities and federal hydroelectric marketing authorities. Relatively new arrivals in the market are independent transmission companies (ITCs), who now have a growing role in expanding and modernizing our nation's transmission infrastructure. Entry of ITCs will not resolve all of Colorado's transmission challenges, however opening the transmission enterprise to competition warrants investigation. States' utility statutory and regulatory structures have been identified by the ITCs as large considerations when selecting the states where they invest capital.

Recommendation:

- Further discussions should be explored to determine the rules and regulations under which ITCs could operate in Colorado. This could potentially be accomplished by amending the state's utility statute or amending certain PUC regulations.

The Colorado Governor's Energy Office's STAR Project has produced these elements:

- An Executive Summary and Key Messages for Decision-Makers
- The STAR Report
- The STAR Modeling of Colorado's Electric Power Sector
- A PowerPoint of the STAR Project

To access these documents, type "STAR Project" in the search box of GEO's Web site: www.rechargecolorado.com

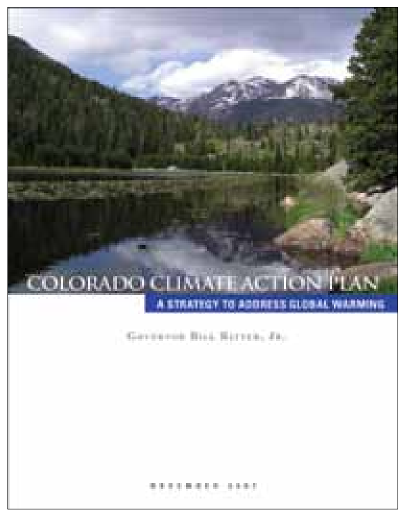
Introduction

This report, *Strategic Transmission and Renewables (STAR): A Vision of Colorado's Electric Power Sector to the Year 2050* is the latest installment in a series of reports on Colorado's electricity sector - STAR builds directly on:

- *The Governor's Climate Action Plan: A Strategy to Address Global Warming,* produced in November 2007.
- *The Report of the SB07-091 Task Force on Renewable Resource Generation Development Areas: Connecting Colorado's Renewable Resources to the Markets*, produced in December 2007.
- *The Renewable Energy Development Infrastructure (REDI) report, Connecting Colorado's Renewable Resources to the Markets in a Carbon-Constrained Electric Power Sector,* produced in December 2009.
- *The 2010 Colorado Utilities report,* produced in August 2010.

These documents provide data and analyses to expand Colorado citizen's understanding of the Governor's policies and his energy office's analyses pertaining to the state's electricity sector. By providing factual data, insights, and recommendations, the reports strive to provide further grounding in the history and future development of Colorado's electricity sector. The reports serve as policy documents that provide reliable information to help advance the vision of Governor Ritter's New Energy Economy, and maintain the substantial momentum that will transform the sector.

The series of documents began when the governor issued the 35-page *Governor's Climate Action Plan (CAP)* in November 2007. This policy document underlies much of Colorado's New Energy Economy. The CAP sets forth how the state can reduce global warming emissions 20 percent below 2005 levels by 2020 and 80 percent by 2050. The CAP states, "By training thousands of workers to improve energy efficiency in our homes, stores and factories, and training thousands of others to build wind farms, solar facilities and geothermal plants across the state. We can reduce our emissions, create jobs and build more sustainable communities."



The plan details numerous actions and goals for state departments, utilities and policy makers. The many activities at the GEO to reduce energy consumption in schools, buildings and homes, to build markets for renewable energy, and to expand transmission to bring green electrons onto the grid, were advanced with the targets of the CAP in mind. Initiatives at the Colorado legislature to raise the level of renewable energy used in the state, and to require that utilities work with customers to reduce demand also tied back to the CAP goals. The state's utilities and many local governments also took the document to heart – even though the plan does not carry the weight of law, Colorado's largest electric utility, Public Service Company of Colorado (PSCo) showed important leadership throughout Governor Ritter's administration. The company began folding the closure of some coal units into its resource plan following the release of the CAP. Later, as part of the 2010 Colorado Clean Air-Clean Jobs Act, PSCo worked with the legislature, the Governor, and many others to modify and retire some of its coal-fired generating stations to help clear Colorado skies. Xcel Energy was named the '2010 Power Company of the Year' by Platts' Global Energy Awards-selected from seven semifinalists, including Duke Energy, Entergy Corp. and Calpine Corporation.

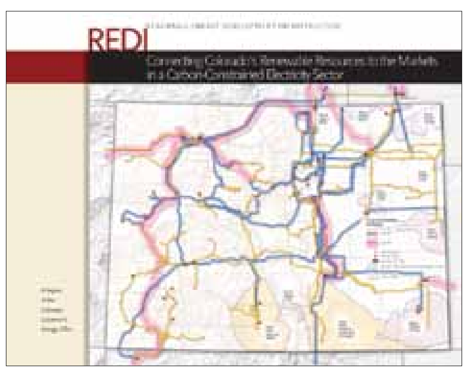
A month after the CAP was issued, the GEO produced the 65-page *SB91 Report of the Renewable Resource Generation Development Area Task Force.* The "SB07-91 Report" report provided the governor, the General Assembly, and the people of Colorado with an assessment of the capability of Colorado's utility-scale renewable resources to contribute electric power in the state. Working with the National Renewable Energy Laboratory, the Task Force quantified 10 Colorado generation development areas (GDAs) that have the capacity to produce more than 1,000 MW. The GDAs have a capacity of more than 96,000 MW of wind generation and 26,000 MW of solar generation. The 16-member Task Force, created by the governor and leadership from the General Assembly recognized that to tap into Colorado's rich renewable

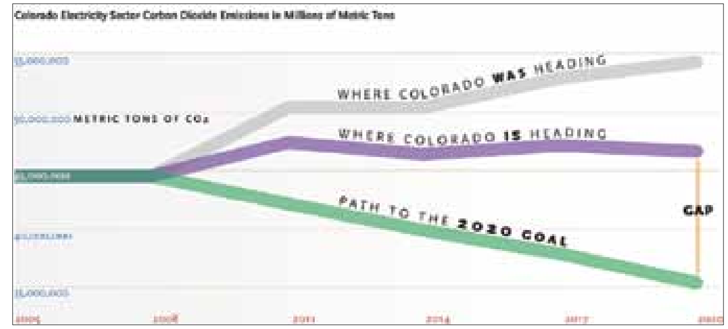
resources will require high-voltage transmission infrastructure to bring the benefits of those inexhaustible and environmentally-benign resources to the markets.

With the mapping embedded as a baseline in Colorado's electricity sector policy framework, GEO then produced a "sequel" to the SB91 report. With help from the United States Department of Energy and technical assistance from the National Renewable Energy Laboratory, the University of Colorado, and three consultants, the GEO produced the 100-page *Renewable Energy Development Infrastructure (REDI) report, Connecting Colorado's Renewable Resources to the Markets in a Carbon-Constrained Electric Power Sector.*

The REDI report is a thorough investigative project designed to provide data to help expand the discussion regarding Colorado's options on how the state's electricity sector can best plan for its near-term future in a carbon-constrained world. The REDI project focused on how the state's electricity sector could achieve the CAP's near term goal of achieving a 20 percent reduction in the sector's carbon dioxide (CO_2) emissions by 2020 (from a 2005 base line). The REDI project referred to this as the "20x20" goal.

Modeling of the state's CO_2 emissions by the University of Colorado Denver's College of Engineering was a key feature of the report. The graphic to the right represents the findings. The top line of the graph indicates the trajectory of CO_2 emissions based on the direction of Colorado's electricity sector before the legislature passed demand-side management and renewable energy goals prior to 2005. The middle line shows where the Colorado electricity sector was heading in the year 2007, taking into account laws and regulatory





rules that prescribe renewable energy and energy efficiency outcomes. The bottom line shows the trajectory of CO_2 emissions that Colorado's electricity sector would need to meet to reach the 20x20 goal. As indicated, Colorado faces a CO_2 emissions gap between where the electricity sector's existing policies will reach by 2020, as compared to the 20x20 goal.

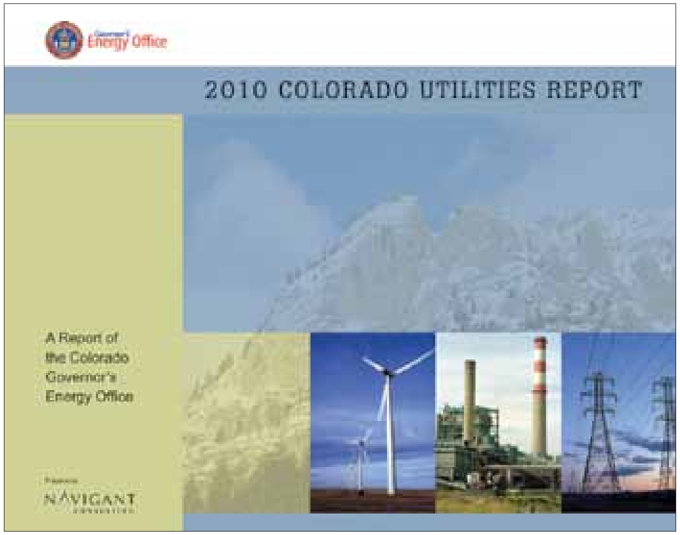
The REDI report addressed how Colorado's electricity sector could close this gap and concluded that, if the sector is to meet the 20x20 goal, the following steps should be taken:

- Greatly increase investment in demand-side resources (energy efficiency, demand-side management, demand response, and conservation).
- Greatly increase investment in renewable energy development, particularly utility-scale wind and solar generation.
- Accelerate construction of high-voltage electric power transmission to deliver renewable energy from Colorado's renewable resource GDAs to the state's major load centers.
- Strategically use natural gas-fired power generation to provide needed new power to the grid and to integrate naturally variable renewable resources.
- Consider decreasing the utilization factor of coal-fired generation and/or consider early retirement of the oldest and least efficient of the state's coal fired generating stations.

Other segments of the REDI project included 450 pages of technical reports containing specific results that helped provide factual data, insights, and analysis for the REDI project, and a video available on YouTube – enter "Colorado Renewable Energy."

Subsequent to the release of the REDI report, the Colorado General Assembly passed two landmark electricity sector laws - an updated "30% by 2020" renewable energy standard, and the Clean Air-Clean Jobs Act. With these laws, achieving the REDI goal of "20x20" was now facilitated, and a new analysis was suggested for a future report- the STAR report. The new analysis, described in depth in the STAR report, is the CAP's "80x50" goal- an 80 percent reduction in CO_2 emissions by 2050.

In August 2010, GEO released the 96-page *2010 Colorado Utilities Report.* The report contains a general description of Colorado's complex and unique electric and gas utility marketplace. It outlines the generation resources, operating data, and governance structure of Colorado's 65 electric and gas utilities. The report provides a data-driven picture of rural, municipal, and investor owned utilities and the resources they use to generate, transmit, and distribute the fundamental energy of our society to your doorstep.



Insights Regarding the Electricity Sector from an Interview with Governor Ritter

In December 2010, Governor Ritter was interviewed by Reuters, with the lead line: "America's Greenest Governor Discusses Smart Growth, Clean Energy." The governor said that "cultivating a competitive edge in energy and sustainable development is what we should be doing. Creativity, innovation, and commercialization – these should be in 21st century America's wheelhouse. That's who we've always been as a country. This vision is among the things I am proudest of accomplishing during these past four years."

When asked about legislative initiatives, the governor said: "None of this was easy. Battles occurred within constituencies. Inside the environmental community, we had those who wanted more. In the renewable energy community, some didn't want us to carve out as much as we did. Small solar wanted market segmentation, large solar wanted something else. Ultimately, we managed to mediate among all the interest groups although the naysayers thought it couldn't be done. Our utility Xcel Energy played a big role in helping to create a consensus."

When asked about what policy mix would ensure America's energy security without compromising the environment, the governor responded: "Our balance of trade deficit weakens us in this country. This is due to importing hundreds of billions of dollars worth of oil each year. If we domestically produce our own energy, it would help. Where the controversy arises is the debate over climate change. I believe that climate change is human caused, but there are so many other reasons to explore new energy solutions. For example, we can exchange dirty inefficient coal plants for natural gas. It's the cleanest of the fossil fuels. Compared to coal combustion, burning natural gas releases no mercury, very small amounts of sulfur dioxide and nitrogen oxide, almost no ash, and 35 percent less carbon dioxide. This provides tons of power and reduces emissions in a very significant way. In being realistic about natural gas, we can achieve a reduction in emissions of 20 percent by 2020 and work a plan to reduce emissions by as much as 80 percent by 2050."

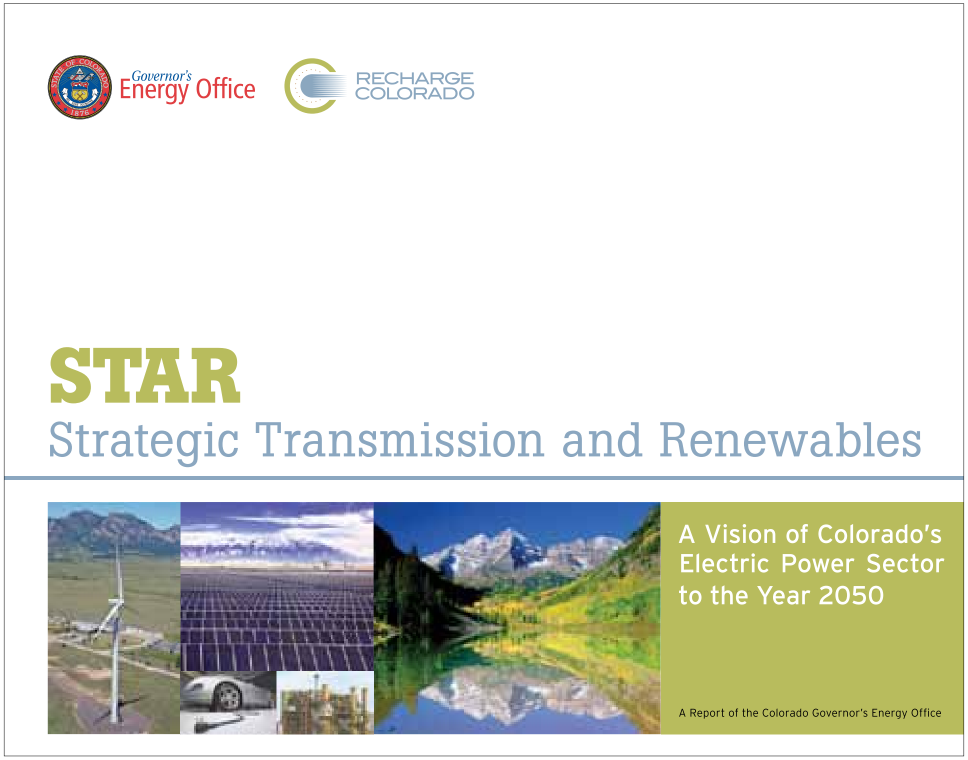
When asked whether the natural gas industry been a cooperative participant in his vision for a New Energy Economy, the governor responded: "There are some people in the natural gas world who see this as suspect, but those who are beginning to understand this see its potential. When I became governor, I had problems with the oil and gas industry, but we've made reforms to ensure cleaner extraction. Now that we've done our best to manage drilling in a way that safeguards habitat and communities, I am comfortable with natural gas. By taking the long view in this conversation, I've now become a promoter of natural gas."

When asked whether partisanship is the culprit in the stalemate regarding a national clean energy policy, the governor said: "I wouldn't say partisanship threatens to impede a 21st century energy policy as much as politics does. Based on my experience, this isn't Democrats versus Republicans so much as lobbyists and special interests standing in the way. If you see someone opposed to something like energy efficiency, they are probably hanging onto an industry that has seen its day. Voters should be proponents of removing the politics from these issues. Find a way to politically neuter them. The ways to do that are to make the case to people who serve in Congress. Show them that this is good for the economy. Show them that everyone should be interested in job growth and this is the industry that can achieve that. What makes a difference to elected officials is a bottom-up strategy. We need more Americans to understand the virtues behind a clean-energy policy agenda and then go out and educate."

When asked what qualities we should cultivate to be effective change agents in our respective spheres of influence, the governor said: "First, have a vision. There's a scripture that says, 'A nation without vision will perish.' I believe this is true. What is out there 15 or 20 years from now that we should be thinking about? We need to answer that question for ourselves. Second, learn to alter people's thinking about these issues. When I began, a lot of folks regarded this as a zero-sum game. We've been making the case ever since that this is right for the 21st century. Are there ways we can incorporate natural gas into a clean energy world? Yes. There might even exist a way to use coal as a clean burning resource. So, being able to alter people's thinking and not be stuck in your own has helped. Third, mediate. We've mediated negotiations among stakeholders in a variety of ways. Clean air, clean jobs, natural gas, environmentalists and utilities — they've all had a place at the table."

A few weeks before the interview, the *2010 State New Economy Index* was released by the Washington-based Information Technology and Innovation Foundation and the Kansas City-based Ewing Marion Kauffman Foundation. The study assesses how well suited each state's economic structure is for success in an evolving global, information-based economy. It measures 26 indicators to find "the degree to which state economies are knowledge-based, globalized, entrepreneurial, IT-driven and innovation-based." Colorado ranked No. 9 in the study.

Ranked ahead of the Centennial State are Massachusetts, Washington state, Maryland, New Jersey, Connecticut, Delaware, California and Virginia. In a breakdown of categories used to compile the overall ranking, Colorado ranks high in "economic dynamism" (No. 2, behind only Utah), workforce education (No. 3), IPOs (No. 5), and IT professionals (No. 7). The report says Colorado "attracts individuals from other regions who are, on average, more educated than those heading to other fast-growing Western states."



Summary of the STAR Report

Strategic Transmission and Renewables (STAR): A Vision of Colorado's Electric Power Sector to the Year 2050 contains 16 chapters that provide analyses regarding the major influences on Colorado's electricity sector, along with recommendations on a wide variety of topics in these chapters:

- Modeling Colorado's Electric Power Sector
- Multiple Benefits of Demand-side Measures
- Addressing Climate Change and Water Issues Through Renewable Energy
- Recent Colorado Legislative Actions
- Colorado's Transmission Infrastructure
- The Growing Importance of Natural Gas
- The Role of Balancing Authorities
- Cost Recovery and Cost Allocation Challenges
- Federal Action and Inaction
- Regional Planning Activities
- The Feasibility of Exporting Colorado's Renewable Energy
- Promising Transmission and Grid Technologies
- Transmission Planning in Colorado
- Integrating Renewable Energy into the Grid
- Transmission Permitting Challenges
- The Potential for Independent Transmission Companies

In summary, we provide the following synopsis of the STAR report:

Modeling Colorado's Electric Power Sector

To gain quantifiable insight into how Colorado's electricity sector might evolve between now and 2050, GEO commissioned a modeling analysis to consider certain scenarios. The primary metric was achieving the CAP's 80 percent CO_2 reduction goal by 2050 on a 2005 baseline. This is the "80x50" goal. The full modeling report assumptions, data sources, and modeling approaches are part of the STAR project, with a separate report on the modeling available on the GEO website: rechargecolorado.com. Enter "STAR Report" in the search box.

The modeling analysis considered two load growth assumptions, incorporated gas and coal prices, capital construction costs, operating characteristics, etc. from reputable sources, and least-cost portfolio selections.

The modeling indicates that demand-side measures are the most effective means of minimizing total costs. However, even with demand-side measures in place, major new supply-side capacity additions, primarily in the form of utility-scale renewable generation and natural gas-fired generation, must be brought on line to simultaneously meet load growth, CAP goals, and other environmental benefits. The GEO modeling analysis identifies a broad path forward for how much renewable capacity is likely to emerge from the various GDAs in the state. Twenty GW of new renewable energy will need to be interconnected with a transmission system that is already congested. New natural gas plants will also be needed to replace aging coal-fired generation, to integrate variable renewable energy, and to meet load growth.

The first driver is a direction given to the model to achieve Colorado's newly enacted renewable energy standard (RES). The RES requires that renewable energy must supply a minimum of 30 percent of investor-owned utilities' (IOUs) retail sales, and 10 percent of non-IOUs' retail sales by 2020. Demand-side management (DSM) requirements for IOUs were also incorporated in the model at the levels ordered by the PUC to be achieved by 2020. The same DSM investment levels were maintained throughout the modeling years. A second driver is direction given to the model to comply with the CO_2 reduction goals of the CAP. A third driver is the expected CO_2 reductions, and fuel mix resulting from the retirement of Colorado coal-fired generation, an expanded version of Colorado HB10-1365, the Clean Air-Clean Jobs Act. This objective was achieved by allowing the model to perform a retirement scenario, i.e., retirement of all Colorado coal-fired generating station after they reach the age 45 and older beginning in the year 2017.

After these key model drivers were defined, the model was instructed to produce results based on a range of base load forecasts, given the cost and performance of various generation technologies and the related emission rates. The model also performed two sensitivity analyses: 1) a high load forecast (3 percent average annual growth), compared to the base forecast of 1.7 percent; and 2) a 20 percent higher natural gas price than the base natural gas price.

The results of the modeling are clear, and are consistent with the findings of the REDI report. Colorado's 1.7 percent annual average annual electric power load growth is likely to continue unless the state's 1.5 percent annual population growth and economic growth stagnate. Demand-side measures will have an increasing, perhaps major, role to play, but ought not be viewed as a substitute to utility-scale renewables and the related need to expand high-voltage transmission infrastructure. To achieve the 80x50 goal will require the maximum potential operational penetration of utility-scale renewable energy, with a complementary expansion of natural gas-fired generation to integrate naturally variable renewables, and the capability of ramping up to meet a growing load as it grows.

Multiple Benefits of Demand-side Measures

Major opportunities exist for demand-side measures, and policies should be encouraged to increase the contribution of a variety of techniques, including demand-side management, demand response (DR), and distributed generation (DG). These approaches present important opportunities to reduce the need for new utility-scale generation, and, to an extent, may reduce the need to expand transmission infrastructure. Colorado has stepped forward with legislation, regulatory policies, and efficiency programs that capitalize on the DSM opportunity. Demand side measures will benefit by the advent of smart grid technologies to help reduce load growth and minimize costly peak demand requirements.

Colorado is stepping forward by deploying smart grid technology as a key enabler to integrate these opportunities, allowing utilities to move ever closer to achieving an optimal balance of demand-side and supply-side resources.

Colorado utilities can benefit from the policies, regulations, and infrastructure advanced by the legislature and the PUC to pursue aggressive, cost-effective demand-side measures that will strengthen the system and avoid some of the need for costly generation. The extent to which utilities and policy-makers take advantage of these opportunities has yet to be fully exercised. By themselves, however, demand-side measures will not change the remaining need for high-voltage transmission to connect the utility-scale renewable resources necessary to meet a variety of electric, environmental, and economic imperatives.

When evaluating electric technologies, analysts should address the CO_2 challenge, the need to enhance environmental performance, avoid water-intensive technologies, be cost and price effective,and assure the ability to be deployed in a reasonable time frame.

After identifying identify Colorado's utilities' existing financial incentives to generate and sell electric power, the legislature, utilities, and regulators should craft structural modifications to align utilities' incentives with the success of their demand side initiatives.

Addressing Climate Change and Water Issues Through Renewable Energy

Although opinions certainly vary about its causes, the long-term warming trend over the last century has been well-documented. Increased warnings from the scientific community point to a growing body of data that indicate rising dangers from the build-up of human-related greenhouse gases—produced mainly by burning fossil fuels and forests. Scientists worldwide have thoroughly studied climate change, and most project a variety of results, including more frequent and intense extreme weather events, disruption of water supplies, and negative effects on agriculture, ecosystems, and coastal communities.

Population growth leads to an inexorable need for more water, placing pressure on agriculture. Increasing water use in a semi-arid state forms a nexus with strategic electric power questions facing Colorado, since traditional electric-generating technologies use large volumes of water. Since wind power and photovoltaics use only a tiny fraction of the water consumed by other generation choices, it is in Colorado's interest to make wind and photovoltaics technologies of choice. If deployed with air cooled technology, concentrating solar power can minimize what otherwise would be consumption of large volumes of water.

Many simultaneous approaches are immediately available in the electricity sector to address climate change, and to mitigate water and drought risks. This is certainly the case with regard to more aggressive deployment of utility-sponsored demand-side measures. Another effective course of action—and the reason more than half the states have passed renewable portfolio standards—is deployment of utility-scale renewable energy generation.

Although risks and adjustments will be encountered, retirement of the heaviest polluting power plants is necessary to minimize CO_2 and meet other environmental objectives. For these reasons, the STAR project and the Colorado Coordinated Planning Group's Conceptual Planning Work Group have modeled the implications of retiring Colorado's fleet of coal-fired generation. Displacing this generation will require utility-scale renewable energy and natural-gas fired generation. A diversity of fuels should be considered, potentially a combination of fossil fuel plants with carbon capture and sequestration (CCS), distributed generation, energy storage, and nuclear power. When weighing these options, rigorous evaluation is required to determine if the options can meet certain objectives. These objectives may include addressing the CO_2 challenge, enhancing environmental performance, avoiding water-intensive technologies, addressing cost and price effectiveness, and assuring the ability to be deployed in a reasonable time frame.

Recent Colorado Legislative Actions

Since elected, Governor Ritter has signed 57 bills relating to clean energy. The governor has said that "we have a story to tell in Colorado. We're proud of that story. We don't think it's the end of that story at all. It's really only the beginning. It is perhaps a template for other states to look at." Colorado has developed an ecosystem from clean energy that goes from the laboratory to production. In tandem with the legislature, the governor has worked to diversify the state's energy portfolio, tying in jobs and finding a way to frame climate change.

Two new state laws are particularly important in the reshaping of Colorado's electric power future.

In March 2010 the governor signed HB10-1001, the renewable energy standard (RES), into law. The act requires Colorado's investor owned utilities reach a minimum of 30 percent renewable electricity by 2020. Colorado's new RES is the second highest in the nation and the highest in the Rocky Mountain West. The act also creates a "carve-out" for DG that will provide a major economic boost to the state's solar industry.

In April 2010 the governor signed HB10-1365, the Clean Air-Clean Jobs Act, into law. The act was passed in anticipation of federal Clean Air Act requirements that will require improved environmental performance in the electricity sector in Colorado's northern Front Range, which is in noncompliance with ground-level ozone standards. Unless the area makes efforts toward compliance, it risks fines and a withholding of federal highway funds. The act requires a reduction in nitrogen oxides (NOx) emissions of 70 percent to 80 percent by December

2017 from coal-fired electric power generation plants operated by Colorado IOUs, principally PSCo. For PSCo, the act calls for retiring the lesser of 900 MW of coal-fired electric generating capacity, or 50 percent of the utility's coal-based capacity, not including capacity that PSCo already was planning to retire before January 1, 2015. The Colorado legislature recognized that a proactive and coordinated effort to reduce emissions from coal-fired power plants, rather than a piecemeal approach, will allow the state to more cost-effectively comply with federal law and plan for efficient integration of replacement resources. The PUC held hearings and has issued a final order that meets the provisions of the law. A detailed white paper on HB10-1365 is available on the GEO website.

Colorado's Transmission Infrastructure

Colorado's high voltage transmission infrastructure (defined as 230 kilovolts (kV) and 345 kV) has developed over the decades and needs to expand for reliability purposes and to deliver large blocks of renewable energy to the markets. Transmission is built to connect generation to the loads, and given the opportunities that are now apparent - the need for improved environmental performance of the electricity sector and economic goals - Colorado is preparing for necessary expansions. Utilities, regulators, and key stakeholders are working together to find new approaches to these opportunities.

Colorado has 57 electric utilities, but only a few own and operate high-voltage transmission. Fifty-four Colorado utilities are nearly exclusive retail distributors of power- either rural electric associations or municipal utilities. Colorado Springs Utilities and Platte River Power Authority have relatively few miles of high-voltage transmission, built to meet their needs.

PSCo is the largest transmission owner and operator in Colorado. The company is subject to SB07-100, which was followed by PUC rules that require IOUs to submit plans on how they plan to build transmission to "beneficial energy resource zones." In tandem with the company's SB07-100 plans, PSCo's transmission plan proposes 40 separate transmission projects over the next five years to reliably satisfy load growth and to accommodate new retail and wholesale customers. The company's transmission planning analyses also covers state, regional, and federal initiatives and requirements.

Tri-State Generation and Transmission Association, Inc. is a wholesale electric power supplier owned by the 44 electric cooperatives it serves (18 in Colorado, 12 in New Mexico, eight in Wyoming, and six in western Nebraska). Tri-State is Colorado's second-largest electric utility. The association owns, operates, and maintains a 5,267-mile high-voltage transmission network and 135 substations and switching stations in the four states it serves. Tri-State has several transmission expansion plans under consideration and development.

Western Area Power Administration markets and delivers reliable, cost-based hydroelectric power and related services within a 15-state region of the central and western United States. Western is one of four power marketing administrations within the DOE which market and transmits electricity from multiuse water projects. Western owns and operates more than 17,000 circuit miles of transmission lines, 258 substations, and other electric power facilities in its 15-state service territory. Like PSCo and Tri-State, Western has a variety of transmission plans, albeit much less expansion plans activity in Colorado than PSCo and Tri-State.

The Growing Importance of Natural Gas

Natural gas has emerged as the critical fuel of the future for several energy sectors, especially the electricity sector. Natural gas is attractive to electric power system planners for a variety of reasons. Natural gas generation is widely expected to provide an ever-growing fraction of the electricity sector for at least the next decade, and likely much longer. Natural gas is a key component not only to the electricity sector, but also in the residential, commercial, and industrial sectors. National forecasts indicate that natural gas- fired electric generation will increase by more than 30 percent during the next ten years, while coal-fired generation, which currently provides about half of the power in the U.S. will grow by only 6 percent. Recent optimistic supply forecasts and the prospect of low and stable prices have reinforced the opportunities for natural gas for baseload power generation. In addition, natural gas generation has the important attribute of the ability to ramp up and down, helping to integrate naturally variable renewable energy.

Colorado ranks sixth among all states in natural gas production. According to the Colorado Oil and Gas Association, approximately 10 percent of the nation's natural gas reserves and ten of the nation's 100 largest natural gas fields are located in Colorado. Oil and gas drilling in the state provides an economic impact of $23 billion per year, employs more than 70,000 people, and provides over $135 million in revenue to the state, including nearly 90 percent of state severance taxes. Colorado is responsible for more than 25 percent of all coal-bed methane produced in the United States. Three-fifths of Colorado's natural gas is exported to meet demand in other states. With an estimated 21,850 billion cubic feet of dry natural gas, Colorado has 9.2 percent of the nation's supply.

Proven reserves of natural gas in the United States have grown significantly during the past several years, largely due to shale gas. In a speech in April 2010, Energy Secretary Steven Chu said that, "new natural-gas drilling technologies have definitely increased reserves by about 30 percent and probably doubled U.S. reserves."

The STAR modeling quantifies the need for a dramatic increase in natural gas generation in Colorado's electric power system. This increase is necessary to meet load growth, displace aging coal-fired generation, and provide necessary firming and integration of variable renewable resource generation.

The Role of Balancing Authorities

Colorado can be viewed somewhat as an electric island that lacks the transmission infrastructure to connect to major adjacent markets. Colorado utilities are not part of a liquid electricity market characterized by regional transmission organizations (RTO) or an independent system operator (ISO). The market is considerably different than the "organized" and central markets that serve the majority of U.S. electric customers. It may be unlikely that Colorado and other western states will form an ISO/RTO structure in the foreseeable future. If so, it makes it more difficult for Colorado to integrate variable sources, such as wind energy.

With this background, many utilities and wind energy developers see the need to perform "workarounds" that might not achieve the optimal results found in an ISO/RTO structure, but nevertheless can make some necessary progress. According to NREL and GE's May 2010 *Western Wind and Solar Integration Study*, there are savings that reach into the billions of dollars through more effective integration of variable resources by balancing authorities. Some Colorado utilities are considering mechanisms to pursue "virtual consolidation" of Colorado's two balancing areas to operate more as if they were a single entity. Such mechanisms may include all or some aspects of dynamic scheduling, intra-balancing area scheduling at subhourly time steps, or other wide-area economic dispatch concepts that do not require actual physical balancing area consolidation.

Cost Recovery and Cost Allocation Challenges

Cost recovery describes how utilities receive recovery on capital costs expended. Cost recovery for transmission investments is often contentious because the regulatory process traditionally has a tendency to limit cost recovery to investments in near-term infrastructure. This results in forgoing more beneficial, higher-voltage, longer term investments. Sub-optimal investments are the result. We see this in Colorado when it comes to lower transmission voltages being planned compared to what will be needed if the state is to build out our vast renewable resources according to a strategic vision of the electricity sector out to 2050 and beyond.

Cost allocation is the term used to describe how the costs of a capital investment such as a transmission line will be allocated to the various entities that use, or benefit, from the line. The cost allocation issue receives considerable attention because allocation outcomes define the costs to be paid by various stakeholders that provides a wide range of benefits to a variety of customer classes. The cost allocation question is at the heart of FERC's efforts to define a common cost allocation methodology.

These two terms—cost allocation and cost recovery—are sometimes confused and used interchangeably, but their meanings are different.

As transmission constraints continue, cost allocation will remain an important topic at both the federal and state levels. The question will persist from a cost-benefit perspective regarding who should pay for state and regional transmission expansion.

The Federal Energy Regulatory Commission (FERC) issued its Order 890 in 2007. The order requires utilities to report to the FERC that describe the utilities' transmission planning processes and how those processes meet nine key planning principles. Through this process, the FERC encourages greater coordination among neighboring transmission providers and interconnected transmission systems, state regulatory authorities, and others.

FERC has issued a Notice of Proposed Rulemaking on transmission planning and cost allocation. Anticipation of a new FERC order creates a new level of expectation and uncertainty in discussions regarding transmission and cost allocation policy. Should the FERC issue an order approximate to that proposed in the NOPR, compliance would incrementally move the U.S. closer to the goals of increased renewable integration with the commensurate benefits of CO_2 reduction and other environmental goals. At the same time, the new rule may represent a concern to certain transmission providers that may prefer to proceed at their own pace with a minimum of what they may perceive as FERC interference.

Colorado policy-makers should encourage both the FERC and the PUC to exercise their pivotal roles to minimize uncertainties that may be inhibiting the right-sizing of transmission lines that are directly traceable to the cost allocation and cost recovery issues. The return of a strong federal role in national transmission infrastructure development should be actively pursued by Colorado policy-makers.

Federal Action and Inaction

During the past 30 years considerable federal efforts have been made to introduce legislation aimed at crafting a national energy policy. Until such time that the congressional-sponsored energy and environmental agendas are resolved, industry and government policymakers will operate under with varying degrees of uncertainty regarding how—and whether—to make strategic decisions. At the top of key unresolved initiatives that cause uncertainty for the electricity sector are the prospects for a national or international approach to reduce greenhouse gases, and the prospects for a national renewable (or clean energy) portfolio standard.

In June 2009, the House of Representatives passed the American Clean Energy and Security Act (ACES). The legislation, also commonly referred to as the Waxman-Markey bill received varying levels of support from electric utilities, energy companies, manufacturing, industry, unions, community, and environmental organizations. The bill was introduced in the Senate and placed on its calendar in early July 2009. After a year of failed efforts to garner bipartisan support, Senate Majority Leader Harry Reid shelved the legislation in July 2010, acknowledging insufficient backing for its passage. The ACES is generally regarded as the reference point for most expectations of what both houses of Congress may eventually pass.

Given the proponents' inability to muster sufficient support for ACES, several bills—more limited in scope—were introduced by members of both houses of Congress. These cover a broad range of energy topics, and, in many cases, are related, duplicative and, or, overlapping.

In addition to the influence of congressional action, FERC and the EPA have substantial authority with respect to regulating and overseeing domestic energy markets. FERC and EPA have embarked on various initiatives that may have long-term structural influences on the future of the electricity sector and, as primarily a derivative, the future of transmission planning and development.

National and international concerns about global climate change will continue to place pressure on policymakers to reduce CO_2 emissions and other greenhouse gases. Several approaches to control emissions have been proposed, and each results in a different benefit and potential price range for carbon. Despite wide and uncertain CO_2 price ranges, utilities and others must continue to develop resource plans to ensure adequate resources for their customers and constituents. Lacking a clear path forward, utilities often model a wide range of scenarios in order to understand the effects these uncertain futures may have on their resource strategy.

This uncertainty is directly felt in the transmission planning community because the potential effect of carbon prices is a major factor in determining what choice of generation technologies will be preferred and the scale of the transmission infrastructure needed to support their choice. Certain generation or transmission projects in the planning stage face continuing uncertainty until these foundational issues are resolved. The effects of the economic downturn further complicate the uncertainty. To a limited extent, the uncertainty has been relieved as a result of the passage of the December 2010 tax bill, which provides an extension of federal loan guarantee support for renewable energy projects.

Many states, including Colorado, have stepped in to fill the federal policy gap by implementing their own environmental and energy policies. Although this provides greater clarity in a particular state, the interdependency of the electric markets among neighboring states means regional solutions cannot be predicated on assessing the aggregate collection of individual state actions.

Regional Transmission Planning Activities

In Colorado's region, two of the most important entities involved with regional transmission planning are the Western Governors' Association (WGA) and the Western Electricity Coordinating Council (WECC). These two organizations are the umbrella structures through which much of the transmission policy and technical coordination occurs. WECC is responsible for regional transmission planning, and the WGA conducts regional transmission planning policy and resource assessments in the Western Interconnection.

The WGA coordinates a wide variety of projects, focusing on issues related to the West. The current Regional Transmission Expansion Project (RTEP) funded by the DOE, is a significant undertaking and will greatly improve the regional ability to plan for new transmission. The RTEP builds upon stakeholder recommendations made as part of the WGA's and DOE's Western Renewable Energy Zones (WREZ) initiative. The WREZ project was initiated in 2008, and a Phase 1 report that included a map of high-quality, developable renewable resource areas was completed in 2009.

The WECC members, recognizing the need for a regional approach to transmission expansion planning, organized the Transmission Expansion Planning Policy Committee (TEPPC) to provide transmission expansion planning coordination and leadership across the Western Interconnection. TEPPC works in close coordination with subregional planning groups, transmission operators, and others to facilitate regional economic transmission expansion planning.

The functions performed by TEPPC complement, but do not replace, the responsibilities of WECC members and stakeholders regarding the planning and development of specific projects.

Transmission planning is evolving to incorporate a wider community of stakeholders with valid interests. Much of this evolution has been encouraged by the FERC and the DOE, and, in general, utilities have embraced the opportunity to work with a wider audience of transmission stakeholders. The WGA and WECC are investing significant time and effort in developing committees and working groups to coordinate the wide range of perspectives on this issue. Most observers expect to see continued results in this area in the relatively near future.

The Feasibility of Exporting Colorado's Renewable Energy

Colorado is rich in renewable resources. However, the state is transmission-constrained and geographically remote to large loads that , in concept, if the price was right, would purchase Colorado's renewable energy exports. The largest markets for renewable energy purchases lie in the Southwest (Arizona, Nevada, and Southern California). These states have aggressive RPS goals and accessing the Southwest and Southern California markets is of keen interest for renewable developers in the west, certain utilities, and others.

Although Colorado has vast wind and solar resources, other nearby Western states also have rich renewable resources. A conceptual export market opportunity may exist for Colorado renewable resources to the Southwest and Southern California. However, other states have an important advantage of being closer to the large load centers. Getting access to these markets is challenging, requiring large capital outlays that would depend upon satisfactory answers to cost recovery and cost allocation questions.

From a Colorado perspective, the primary interstate bulk power transmission project currently under consideration for Colorado is the High Plains Express Transmission Project (HPX). If developed, HPX would access the wind-rich plains of southern Wyoming and eastern Colorado, and then move through New Mexico and Arizona to reach the power markets in the southwest. There are several conceptual competitors to the HPX.

NREL and GE's *Western Wind and Solar Integration Study* contains important information regarding whether new long-distance transmission is needed to the extent that many envision. The *WWSIS* report states that the in-area scenario which assumes each state meets its RPS targets using the best wind and solar resources within each state boundary, and which included no additional interstate transmission, operated as well as the other scenarios studied in the report. Up to 20 percent renewable penetration across the West could be achieved with little, or no, new interstate transmission additions, assuming full utilization of existing transmission capacity. The study concluded that 30 percent wind and 5 percent solar penetrations were feasible, but they would require key changes to current practices involving many factors.

The recovery of costs under the current regulatory environment and the lack of compelling advantages of Colorado's wind and solar resources, compared to southwest states that are much closer to load centers, represent considerations when assessing the prospects of building transmission in Colorado with the primary purpose of exporting the power to the southwest.

Colorado needs to maintain and strengthen its relationships with the High Plains Express, the Colorado Coordinated Planning Group's Conceptual Planning Work Group, and other entities that are continually analyzing the opportunities for exporting Colorado's renewable energy.

Promising Transmission and Grid Technologies

Contemporary observers of the electric power system may point out that Thomas Edison would recognize many technologies used for long-distance power transmission today. Standard electric transmission technologies have proven their worth over time, and thousands of incremental improvements to transmission technology have contributed to electric power— what the National Academy of Engineering has called "the greatest engineering achievement of the 20th century."

Advanced technologies are steadily emerging that are designed to meet new demands on the electric system in the digital age. These new demands include the integration of increasing amounts or variable renewable generation, the evolution of wholesale trading in some markets, and increased responsibility to ensure security and reliability.

An important potential exists for new transmission technologies to substantially increase the throughput of electricity compared to past practices. However, utilities and regulators operate in an investment and statutory environment where risk-taking is arguably not their trademark. The challenge is how to ensure timely deployment of new transmission technologies in a risk-averse environment. Although the rate of change is often frustrating and slow, new technologies are increasingly being deployed that offer improvements to the electric power system.

Colorado utilities should expand their work with interested stakeholders and report to the legislature and the PUC regarding their findings to determine what policy changes and changes in practice should take place to ensure that Colorado benefits by a more rapid introduction of new transmission-related and storage technologies.

Transmission Planning in Colorado

The responsibility for much of Colorado's transmission planning takes place under the auspices of the Colorado Coordinated Planning Group. CCPG is a joint, high-voltage transmission system planning forum operating within the WestConnect footprint. CCPG's purpose is to ensure a high degree of reliability in the planning, development, and operation of the high-voltage transmission system in the Rocky Mountain region. The CCPG provides the technical forum required to complete reliability assessments, develop joint business opportunities, and accomplish coordinated planning under the single-system planning concept in the Rocky Mountain region of the WECC. Single-system planning is defined as the planning necessary to most efficiently use the existing transmission system and to make the appropriate additions, upgrades, and enhancements to the system on a best-cost basis as if it were owned by a single entity.

CCPG and its subcommittees represent an effort primarily by the utilities, and to a lesser degree by stakeholders, to move Colorado in the direction of unified transmission planning with a goal of single-system planning. Closer coordination between Colorado's utilities and the PUC is being explored through a new PUC rulemaking proceeding.

The PUC recognizes that transmission planning in Colorado needs to be more comprehensive, with a longer time horizon, with increased coordination with generation planning, and featuring greater stakeholder involvement. The PUC is expected to initiate a formal rulemaking proceeding in 2011 to accomplish these goals. Colorado will benefit if these goals are accomplished, as it will result in closer cooperation between utilities and stakeholders, featuring more diverse involvement in the planning process. Utilities and policy decision makers are being urged to further professionalize the CCPG's sub-regional transmission planning processes in Colorado to emphasize strategic future priorities, such as minimizing environmental impacts, minimizing water consumption, and embracing new technologies and practices.

Integrating Renewable Energy into the Grid

As renewable penetrations reach higher percentages of a utility's portfolio, grid stability needs to be managed in innovative ways. A new balance is being approached to maintain or enhance reliability while integrating ever-higher fractions of wind and solar. Nationally and internationally, stakeholders have conducted many studies that consider numerous solutions focused on successful integration of variable resources. These solutions are being tested across the U.S., following many years of improvements in Europe, with successful results that provide opportunities for increasing the integration of considerably more renewable resources in the coming years.

In the western U.S., wind and solar integration is becoming increasingly important as renewable resources represent a greater share of utilities' generation portfolios. The renewable standards in four of the five states in the WestConnect footprint require that 15 percent to 30 percent of annual electricity sales be derived from renewable resources by between 2020 and 2025. Most of the states in the WECC have renewable standard requirements, and renewable energy growth in the western region has been substantial.

NREL's *Western Wind and Solar Integration Study's* in-depth analysis concerns the integration of wind and solar into the western regional grid. The report was designed to answer questions that utilities, PUCs, developers, and regional planning organizations have, including whether the integration of renewables can reach 35 percent. The analysis demonstrates that it is operationally feasible to achieve what the study calls "the 30 percent case," a 30 percent penetration of renewable energy, provided significant changes are made to current operating practices. Several other studies have either recently been conducted or are in process regarding integrating wind and/or solar into a utility's, control area's, or other study area's system. Research and recent experience is showing that it is feasible for wind and solar resources to be integrated at higher penetration levels with some changes to traditional practices.

Transmission Permitting Challenges

The intersection of renewable energy generation and transmission infrastructure development with land-use issues deserves special attention. Planning and permitting new transmission lines is complicated and is often a time-consuming process. Construction of renewable generation projects moves relatively quickly compared to a slower process often associated with transmission planning and permitting. Because Colorado's transmission siting process is marked by strong local control and regulation, analysis of the local transmission permitting processes is attracting increased attention by policy-makers.

Regardless of what part of Colorado is under discussion, opposition to a transmission line is always a possibility. Once a utility files an application for a permit to build a transmission line, utilities work with local governments that have the right to impose conditions, such as a requirement to place portions of the line underground or a requirement for more costly routing to accommodate land-use concerns.

Because transmission projects often traverse several municipalities and counties, a transmission developer must follow multiple permitting processes within each jurisdiction through which the project passes. Given the necessity of building out the transmission infrastructure to deliver renewable resource generation to the loads, concerns have been expressed about whether Colorado's relatively unique local approach to transmission siting decision making is a serious enough impediment that it warrants reviewing the potential for reforming the process.

There is growing interest in considering streamlining Colorado's transmission planning and permitting processes. If carefully and effectively carried out, streamlining the approval process (what some call "one-stop permitting") may allow renewable energy and transmission development to occur in a more timely manner.

One approach to streamline the transmission permitting process in Colorado would be to establish a statewide task force on transmission siting and permitting to make findings and recommendations to the governor and the General Assembly. The task force could hear testimony on a range of topics and consider public comments received during a public hearing process, as well as written comments from affected counties, cities, electric providers and customers, environmental groups, and other interested stakeholders.

Another approach could be legislation that establishes a statewide transmission siting authority composed of a balance of local, state interests, coordinating closely with the PUC, and featuring an appeals process, and timelines that require decisions to be made.

The Potential for Independent Transmission Companies

As the drivers for transmission development have evolved and expanded, so, too, have the types of developers, owners, and operators. Historically, virtually all high-voltage transmission built in the U.S. was planned, financed, designed, and constructed by electric utilities and federal hydro marketing authorities. A relatively new arrival in the market is the independent transmission company (ITC). Although at this juncture, comparatively few independent transmission lines exist, ITC projects are growing in strength and number, and have helped to solve certain issues, including relieving congestion, improving reliability, and providing a new access to capital.

The Wyoming-Colorado Intertie Project proposes a new 345-kV transmission project that would stretch approximately 180 miles between the Laramie River Station substation located near Wheatland, Wyoming, and the Pawnee substation located near Brush, Colorado. As envisioned, the project would provide 850 MW of firm transmission service across the TOT3 constraint located at the Wyoming-Colorado border.

A primary risk that concerns ITCs may be a state's utility regulatory environment. Some ITC developers declare in their investment prospectus that they offer investors an opportunity to enjoy more predictable rates of return at the FERC, compared to state regulation.

Independent transmission companies are playing a growing role in expanding and modernizing the nation's transmission infrastructure. Experience shows that regulatory hurdles and financing challenges are the primary obstacles to ITC projects. It remains to be seen whether these issues will be addressed in Colorado through statutory and, or regulatory changes.

STAR Report Conclusion

The STAR project produced this extended update and modeling of work produced in earlier reports issued by the Governor's Office and the Governor's Energy Office. The STAR project provides data and insights to expand the strategic discussion regarding what mix of demand-side and supply-side resources (including high-voltage transmission) should be considered in Colorado, particularly if the state strives to meet the CAP's objective of reducing the electricity sector's CO_2 emissions by 80% by 2050.

The STAR project concludes that a variety of macro-trends point in the direction of strategically considering maintaining the momentum of the past several years, including lowering the load growth through demand side measures, increasing the penetration of utility-scale renewable energy generation up to its operational limits, and replacing aging coal-fired generation with a new generation of gas-fired generation.

Acknowledgments

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Acronyms

ACCR	Aluminum Conductor Composite Reinforced
ACE	Area Control Error
ACEEE	American Council for an Energy Efficient Economy
ACES	American Clean Energy and Security Act
ACSR	Aluminum Conductor, Steel Reinforced
ACSS	Aluminum Conductor, Steel Supported
ADI	ACE Diversity Interchange
AGC	Automatic Generation Control
APA	American Power Act
AWEA	American Wind Energy Association
BA	Balancing Authority
Bcf	Billion Cubic Feet
Bcf/d	Billion Cubic Feet Per Day
BHE	Black Hills Energy
CAES	Compressed Air Energy Storage
CAISO	California Independent System Operator
CAP	Colorado Climate Action Plan
CAS	Chemical Abstracts Service
CBM	Coal Bed Methane
CCGT	Combined Cycle Gas Turbine
CCN	Certificate of Public Convenience and Necessity
CCGT	Combined Cycle Gas Turbine
CCPG	Colorado Coordinated Planning Group
CCS	Carbon Capture and Sequestration
CDOW	Colorado Division of Wildlife
CDPHE	Colorado Department of Public Health and Environment
CIEA	Colorado Independent Energy Association
CLRTPG	Colorado Long-Range Transmission Planning Group
CO2	Carbon Dioxide
CO2-e	Carbon Dioxide Equivalent
COGA	Colorado Oil and Gas Association
CPWG	Conceptual Planning Work Group
CREPC	Committee on Regional Electric Power Cooperation
CSC	Cross-Sound Cable
CSP	Concentrated Solar Power
CT	Combustion Turbine
DG	Distributed Generation
DNI	Direct Normal Insolation
DOE	Department of Energy
DR	Demand Response
DSM	Demand-Side Management
EEI	Edison Electric Institute
EIA	U.S. Department of Energy's Energy Information Administration
EIA	Environmental Impact Assessment
EIS	Energy Imbalance Service
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
ERP	Electric Resource Planning
ERZ	Beneficial Energy Resource Zone
ES	Electricity Sector
ESA	Electricity Storage Association
EV	Electric Vehicle
FAA	Federal Aviation Administration
FCLs	Fault Current Limiters
FERC	Federal Energy Regulatory Commission
GDA	Generation Development Area
GEO	Colorado Governor's Energy Office
GHG	Greenhouse Gases
GW	Gigawatt
GWh	Gigawatt-hour
HPX	High Plains Express Transmission Project
IEA	Interwest Energy Alliance
GT	Gas Turbine
IGCC	Integrated Gasification Combined Cycle
IOU	Investor-owned utility
IPPs	Independent Power Producer
IRP	Integrated Resource Planning
ISO	Independent System Operator
ITC	Independent Transmission Company
kW	Kilowatt
kWh	Kilowatt-hour
kV	Kilovolt
LCOE	Levelized Cost of Electricity

LCRI	Location Constrained Resource Interconnection
LGIA	Large Generation Interconnection Agreement
LSE	Load-serving Entity
LVRT	Low-Voltage Ride-through
MARKAL	Market Allocation (model)
Mcf	Million Cubic Feet
MISO	Midwest ISO
MW	Megawatt
MWh	Megawatt-hour
NASPI	North American Synchrophasor Initiative
NCAR	National Center for Atmospheric Research
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NOPR	Notice of Proposed Rulemaking
NOx	Nitrogen Oxide
NG	Natural Gas
NGCC	Advanced Natural Gas/Natural Gas Combined Cycle
NYMEX	New York Mercantile Exchange
NREL	National Renewable Energy Laboratory
NTTG	Northern Tier Transmission Group
OASIS	Open-access Same-time Information System
OATT	Open Access Transmission Tariff
PDC	Phasor Data Concentrator
PECPA	Practical Energy and Climate Plan Act
PGC	Potential Gas Committee
PHEV	Plug-In Hybrid Electric Vehicle
PMU	Phasor Measurement Unit
PPA	Power Purchase Agreement
PSCo	Public Service Company of Colorado
PSH	Pumped Storage Hydro
PUC	Colorado Public Utilities Commission
PV	Photovoltaics
RDG	Retail Distributed Generation
REA	Rural Electric Association
REC	Renewable Energy Credit
RES	Renewable Energy Standard
RESA	Renewable Energy Standard Adjustment
RPS	Renewable Portfolio Standard
RTEP	Regional Transmission Expansion Project
RTO	Regional Transmission Organization
SCG	Subregional Coordinating Group
SCR	Selective Catalytic Reduction
SNCR	Selective Non-Catalytic Reduction
SGTF	Smart Grid Task Force
SOA	State-of-the-art
SOx	Sulfur Oxide
SPG	Subregional Planning Group
SPP	Southwest Power Pool
SPSC	State/Provincial Steering Group
SPSG	Scenario Planning Steering Group
SREC	Solar Renewable Energy Certificate
SRO	Standard Rebate Offer
TCA	Transmission Cost Adjustment
Tcf	Trillion Cubic Feet
TEPPC	Transmission Expansion Planning Policy Committee
TSG&T	Tri-State Generation and Transmission Association
TSP	Transmission Service Provider
TWE	TransWest Express
USGS	United States Geological Survey
VAR	Volt Ampere Reactive
VG	Variable Generation
WAPA	Western Area Power Administration
WCI	Wyoming-Colorado Intertie Project
WDG	Wholesale Distributed Generation
WECC	Western Electricity Coordinating Council
WGA	Western Governors' Association
WRA	Western Resource Advocates
WIA	Wyoming Infrastructure Authority
WIEB	Western Interstate Energy Board
WREZ	Western Renewable Energy Zones
WWSIS	Western Wind and Solar Integration Study

I. A Vision of Colorado's Electric Power Sector to 2050

1. Modeling Colorado's Electric Power Sector

Overview

A major feature of this report is the analysis of Colorado's electricity sector to the year 2050. By way of background, ownership of the electric generating facilities (primarily fossil-fired power plants, wind farms, and solar farms) is a mix of utilities, and independent power producers that sell their electricity generation output and capacity to utilities. Generating stations burn a variety of fuels—primarily coal and gas—at varying cost and performance efficiencies with related emissions profiles (such as carbon dioxide and criteria pollutants). See Figure 1. Because renewable energy generating plants (e.g., wind and solar) do not burn fuel, they have different cost and operating characteristics and, in the case of wind and solar, do not emit pollutants.

Over the past half-decade, Colorado has experienced a sizeable increase in the deployment of renewable energy to serve the state's electric customers. Power from renewable energy in Colorado now totals approximately 1,450 MW, described in greater detail later in the report.

Colorado has more than 150 fossil-fired generators with more than 1 MW of name-plate capacity, and these generators were modeled for the STAR project.

Many of these power plants were installed several decades ago, and have reached, or are nearing, their retirement. The age and capacity of the generation installed in the Rocky Mountain Region is reflected in Figure 2. The figure illustrates the capacity growth by the year the generation was placed in service. The generation vintage provides an overview of the energy transformation that has occurred in the Rocky Mountain Region's electricity sector over the past century. In the past few decades the largest capacity additions, aside from one 750 MW coal-fired generating station, has been mostly natural gas-fired generation. The last half-decade has witnessed growth in non-hydro renewables, nearly exclusively wind power.

To gain quantifiable insight into how Colorado's electric sector might evolve between now and 2050, GEO commissioned a modeling analysis. A report entitled *Power Sector and Colorado Climate Action Plan Scenario Analysis for the Strategic Transmission and Renewables Report* was produced for GEO by Saeed Barhaghi, PhD. Dr. Barhaghi is an engineering research professor at the Center for Sustainable

Sources of Colorado electric power generation

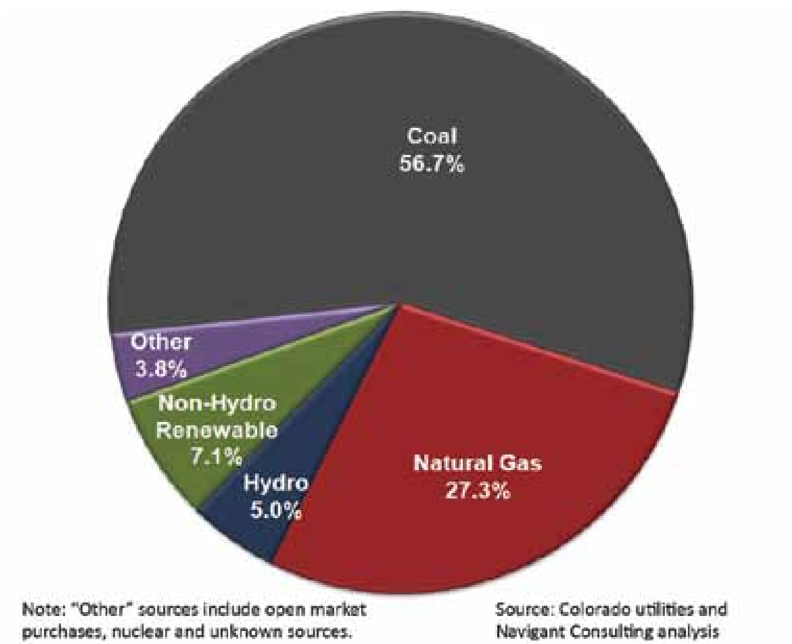


Figure 1: Colorado electric generation (energy) mix
Source: Colorado utilities and Navigant Consulting Analysis

Generation Vintage in Rocky Mountain Region by Fuel Type

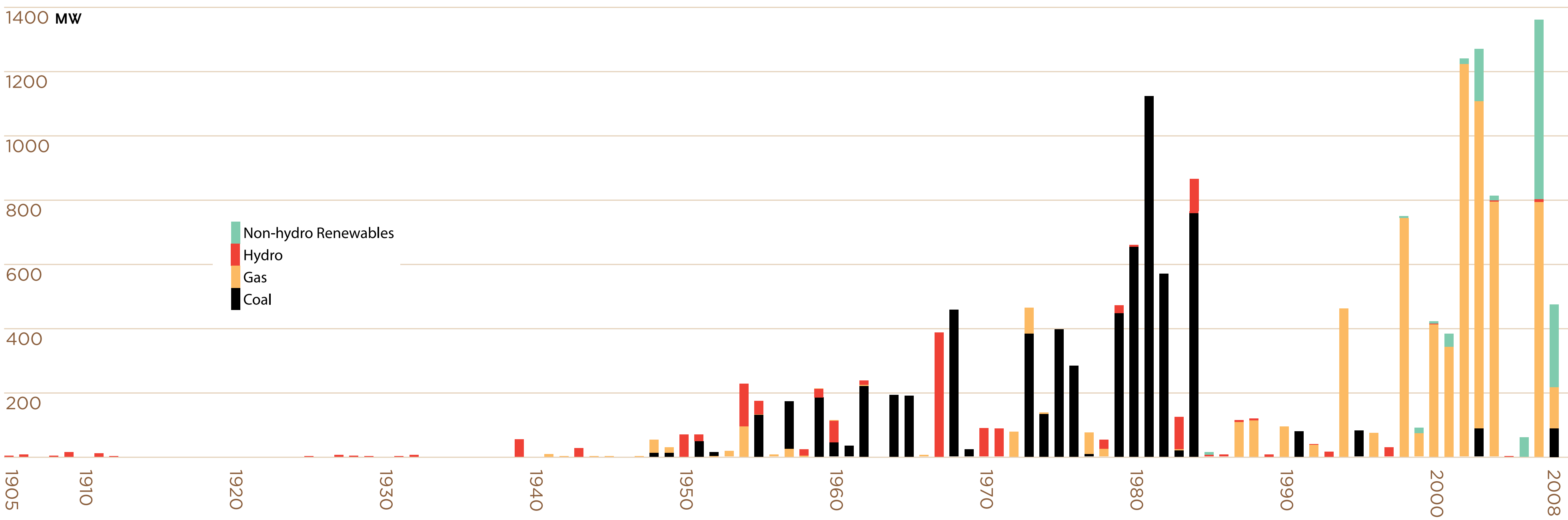


Figure 2: Generation Vintages in the Rocky Mountain Region by Fuel Type

Source: Colorado Governor's Energy Office, REDI report[22]

Infrastructure Systems in the College of Engineering and Applied Science at the University of Colorado Denver. He is also a principal consultant at the consulting firm of E2MG in Denver. The STAR report refers to his work as "the GEO modeling analysis" or "the analysis." The analysis examined expected future Colorado loads and resource requirements under a variety of scenario conditions to develop a picture of how the generation and transmission infrastructure requirements may unfold. Using the MARKAL modeling framework, the analysis investigated certain scenarios of future electric power generation technologies in Colorado and their effects on the environment.[2]

The MARKAL model represents an energy system from the extraction of fuels through their conversion to useful forms of energy to meet end users' demands. It assumes sufficient transmission capacity and market conditions to deliver the low-cost energy. It determines the least-cost pattern of technology investment while meeting the required energy demands and model constraints, and then calculates the resulting environmental impact, such as greenhouse gas emissions, and criteria pollutants. The objective function of the model is to minimize the discounted total system cost of a region (or set of regions, if multiple regions are modeled) obtained by adding the discounted periods' total annual cost. The 38-page GEO modeling analysis, including a detailed discussion of the modeling methodology and results, is available by entering "STAR Project" in the search box of GEO's Web site at www.rechargecolorado.com.

This chapter summarizes the methodology and key results of the analysis. The modeling was produced to provide quantitative support for this report's information regarding the implications for Colorado's future electric power generation and high-voltage transmission infrastructure to the year 2050.

Parameters that affect the model's output: Renewable Energy Standard, Climate Action Plan, and Clean Energy-Clean Jobs

The first parameter directs the model to achieve the newly enacted renewable energy standard (RES) pursuant to Colorado HB10-1001. The RES requires that renewable energy must supply a minimum of 30 percent of investor-owned utility (IOU) retail sales, and 10 percent of non-IOUs' retail sales by 2020. Demand-side management (DSM) requirements for IOUs were also incorporated in the model at the levels ordered by the PUC to be achieved by 2020. The same DSM investment levels were maintained throughout the modeling years.

The second parameter is direction given to the model to comply with the carbon dioxide (CO_2) reduction goals (confined to the electricity sector only) of Governor Ritter's Climate Action Plan (CAP). In this regard, the modeling scenario analysis was instructed to develop a generation portfolio that resulted in the CAP's goal of a 40 percent reduction in CO_2 emissions by 2030 and an 80 percent reduction in CO_2 emissions by 2050, both from 2005 levels. Figure 3 illustrates that 36 percent of Colorado's CO_2 emissions come from the electricity sector.

The third key paramater is to determine the expected CO_2 reductions, and fuel mix resulting from the retirement of Colorado coal-fired power plants, an expanded version of Colorado HB10-1365 —the Clean Air-Clean Jobs Act. This objective was achieved by allowing the model to perform a retirement scenario, i.e.,retirement of all Colorado coal-fired generating stations after they reach the age 45 and older beginning in the year 2017.

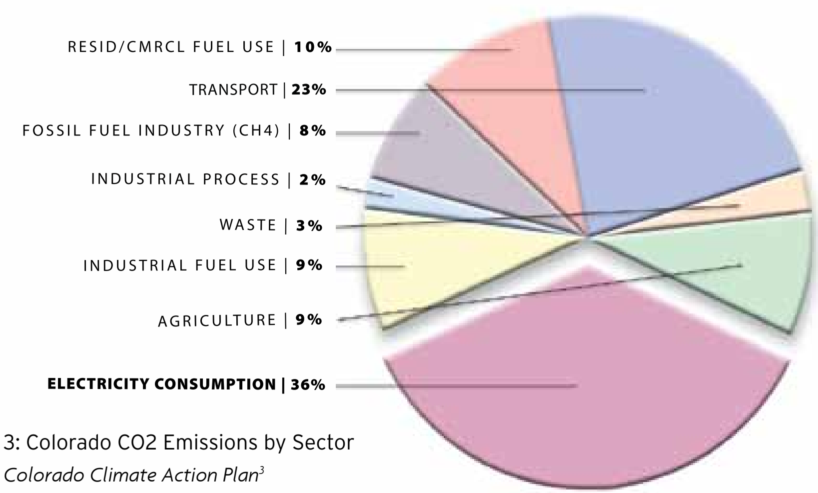


Figure 3: Colorado CO2 Emissions by Sector

Source: Colorado Climate Action Plan[3]

After these key paramaters were implemented in the model, results were based on a range of base load forecast, given the cost and performance of various generation technologies and the related emission rates. The model also performed two sensitivity analyses: 1) a high load forecast (a 3 percent average annual growth), compared to the base forecast of 1.7 percent; and 2) a 20 percent higher natural gas price than the base natural gas price.

Model Assumptions

The following were developed as the primary modeling assumptions:

- The Colorado electricity sector will meet the CAP. The CAP's CO_2 reduction assumption is also being adopted for modeling purposes by the Colorado Coordinated Planning Group's (CCPG's) Conceptual Planning Work Group (CPWG). The model did not incorporate any price on CO_2. Instead, the model constrained the CO_2 emissions levels to meet the CAP goals by allowing the less carbon intensive clean energy technologies and renewables to compete with other conventional technologies, based on cost and performance, to meet the load growth.
- Colorado will experience an aggregate, statewide annual average load growth of 1.7 percent to 2030 and beyond to 2050. Also modeled was a sensitivity of a 3 percent average annual load growth (high load growth). A sensitivity run on a 1.2 percent average annual load growth forecast (the CPWG's low forecast) was not run, since the results would have been quite close to the 1.7 percent results.
- All of PSCo's conceptual SB07-100 transmission lines were assumed to be in service by 2030. This assumption mirrors the transmission assumption that adopted by the CPWG to conduct its analysis.
- For the retirement scenario, all Colorado coal-fired generating stations will be retired during the end of the year when they reach the age of 45 or older, beginning in 2017. In some cases this assumption may not reflect actual utility plans for retiring the plants, since those plans are largely unknown. This assumption conforms in large part with that adopted by the CPWG to conduct its analysis.
- Colorado's HB10-1001 RES will be met or exceeded. The RES requires a minimum of 30 percent renewables by 2020 for IOUs, and 10 percent renewables by 2020 for applicable rural electric cooperatives and municipal utilities. The STAR modeling analysis used a renewable energy policy assumption that is more conservative than that being analyzed by the CPWG. The CPWG adopted a planning assumption that 30 percent of energy generation of the entire Colorado load (both IOUs and non-PUC-regulated utilities) will be from renewable resources, nearly exclusively from wind and solar generation. The CPWG assumes wind generation at a 37 percent capacity factor (attributing this from PSCo data 2010 year to date, with 20 percent of this total generation on-peak, and 80 percent of total off-peak). The CPWG assumes, based on cost, that wind will provide two-thirds of total renewable energy generation. For solar generation, the CPWG presumes that photovoltaics will provide 25 percent of the total, with a 30 percent capacity factor, and with 65 percent of the generation occurring on-peak. CPWG assumes that concentrated solar power (CSP) with storage will constitute 75 percent of the total, with a 50 percent capacity factor, 95 percent occurring on-peak, and 0 percent off-peak. Based on cost, CPWG assumes that CSP will provide one-third of total renewable energy generation.
- Wind generation is constrained to 33 percent penetration through year 2035. The model slowly begins increasing the wind penetration starting in 2036 until it reaches a maximum penetration of 45 percent in 2050.
- Wind resources in generation development areas (GDAs) 1 and 8 are modeled at an average 42 percent capacity factor. GDA 2 is modeled at an average capacity factor of 36.6 percent, and all other GDAs are modeled at 34 percent capacity factor. It is recognized that a wide difference of opinion regarding capacity factors may exist, based upon actual measurements in the field. The STAR project did not have the resources to investigate the capacity factor granularity that may be warranted in a more extensive study. It is recognized that the capacity factors of GDAs will increase substantially when based on the new 80 meter and 100 meter hub height data. However, these new capacity factors were not modeled in the STAR analysis due to lack of

firm data at the time of the modeling. See Figure 20 on page 40 for more information on Colorado capacity factors.

- Nuclear power was made available to the model to compete with all other technologies beginning in 2017. Although the STAR analysis used very low capital cost assumptions for nuclear power when compared to cost data from recent state public service commission regulatory proceedings, nuclear power only appears as a viable source in out years under the retirement scenario coupled with the high load growth and high natural gas sensitivities.
- Coal-fired generation without carbon capture and sequestration (CCS) technology was not modeled, since modeling coal without CCS would automatically defeat the primary purpose of the modeling, i.e., to determine how Colorado's electricity sector will be able to meet the CAP.

Model Definitions

- **Base:** The base run includes no DSM, RES, or CAP. The model builds generation capacity just to meet the 45-year base load forecast (2005-2050), absent DSM, RES requirements, or CAP constraints. The base case was established as a starting point to build a reference case, scenarios, and sensitivities.
- **B+ DSM:** This is the base case that incrementally adds the IOUs' minimum DSM requirements. The model made no assumptions that DSM requirements will be applied to non-IOUs.
- **Reference Case:** This case describes the condition when Colorado's power sector builds to meet the load with consideration given to DSM requirements (assuming no change in state law, i.e., DSM requirements are applicable to IOUs only), the RES (30 percent for IOUs and 10 percent for non-IOUs) requirements by 2020, and projected into the future assuming the RES as a floor. The reference case is synonymous with B+D+RES, where the model incrementally adds the RES requirements after adding the DSM requirements.
- **Reference Case + CAP:** This case describes a carbon policy scenario that has been applied to the reference case. This means that the power sector's CO_2 emissions in Colorado meet the CAP goals by 2020, 2030, and 2050.
- **Biomass CC:** Biomass combined cycle plant.
- **Conv. CC:** Natural gas combined cycle plant.
- **GASSEQ:** Natural gas advanced combined cycle plant with 90 percent CCS.
- **2017:** The model makes an assumption that the technology will be introduced in 2017.
- **Wind-2005:** The case describes wind generation that was installed in the base year 2005. The model takes it as existing renewable generation and builds incrementally beyond that, as needed.

Load Growth and Demand-Side Alternatives

The analysis assumed an average annual load forecast growth rate of 1.7 percent over 45 years (2005-2050). This amount was derived from the aggregate projection of load growth to 2030 supplied to the CPWG by the state's major generating utilities. The model also analyzed outcomes if the state experienced an average of 3 percent load growth beyond 2010. This high load growth could potentially be triggered by a major population influx, a significant increase in economic activity, oil shale on the Western Slope, major new pumping loads for water delivery systems, a major penetration of electric vehicles, some combination of these, and other factors.

Demand-side management is modeled as a conservation resource that contributes to a reduction in total energy requirements, as well as a corresponding reduction in fuel and new capacity over the life of the DSM resource. The model then reinvested in DSM measures at the same 2020 level once the implemented measures reached ten years' life expectancy. The model assumed PSCo's program cost at $895 per kilowatt (kW) for 2010 at the generator, with an escalation rate of 4.6 percent throughout the study period.

Advances in utility-sponsored DSM have been sponsored by IOUs and several non-IOU utilities in Colorado. Future contributions from demand-side measures could, and should, be substantially greater than levels that have occurred in the past. Given the electric load growth projections, and given Colorado's average annual

If Colorado were to experience lower load growth (stimulated in part by aggressive DSM programs), the state could forego the need to add more costly fossil and renewable energy generation.

population growth of 1.5 percent, and a reluctance, to date, by the legislature to set DSM requirements for non-regulated utilities, the analysis employed a conservative approach that assumed no new DSM policies would be enacted during the study period. The modeling employs a prudent approach to not run the risk of having the model underbuild to meet future needs projected to the year 2050. The modeling results clearly indicate that, if Colorado were to experience lower load growth (stimulated in part by aggressive DSM programs), the state could forego the need to add more costly fossil and renewable energy generation. Reducing load growth would yield system benefits approaching $1 billion.

As is apparent in Figure 4, electric power generation is the most costly component in customers' electric bills. Utility-sponsored DSM programs aimed at avoiding construction of generation represent the most beneficial approach to stabilizing customer's bills. Although limitations on GEO's modeling analysis did not permit this report to quantify the range of these benefits, a wealth of data collected during the past three decades has done so.

The Model's Load Forecast

The base energy forecast assumed an annual load growth of 1.7 percent between 2005 and 2050. Population growth is the primary factor that determines load growth. Other primary factors include levels of economic growth and the energy intensity of commercial activity and industries that consume electric power. Like the rest of the United States, Colorado's per-capita electric consumption is increasing, and, as a result, so are overall demands on both electric generation and transmission.

Colorado's population has steadily increased since the end of World War II. The growth rate has fluctuated in concert with population and the economy, but has generally increased during the past 30 years. This population growth translates directly into greater need for both electric power and more aggressive demand-side measures. Various historical national demographic trends indicate that Colorado's population growth is expected to continue.

According to Colorado's State Demography Office (the Office), in 1990, 3.3 million people lived in Colorado; in 2000 it was 4,301,261; by 2010 the number reached 5,029,196. Colorado's population increased by 17 percent from 2000 to 2010, compared with a gain of 9.7 percent in the country as a whole. Colorado's population now tops five million, up by around 700,000 over the past decade. Colorado now has the 22nd highest population of the 50 states, up from 24th 10 years ago. The Office's most recent population projection extends to the year 2040, at which point the Office projects a Colorado population of 8,099,366, growing at an average annual rate of 1.7 percent (Figure 5).

National Average Cost of Electricity

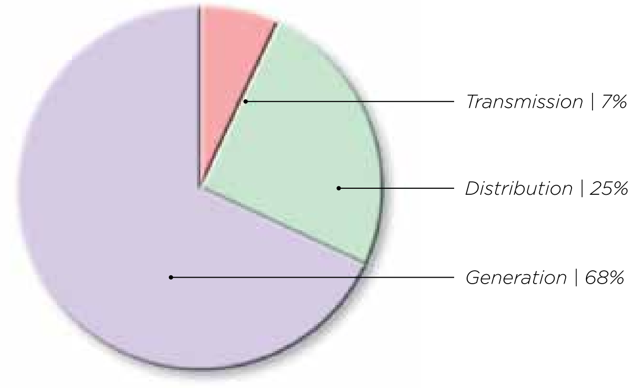


Figure 4: National Average Cost of Electricity
Source: U.S. Department of Energy; Colorado Governor's Energy Office, REDI report[4]

Colorado Preliminary Population Forecast

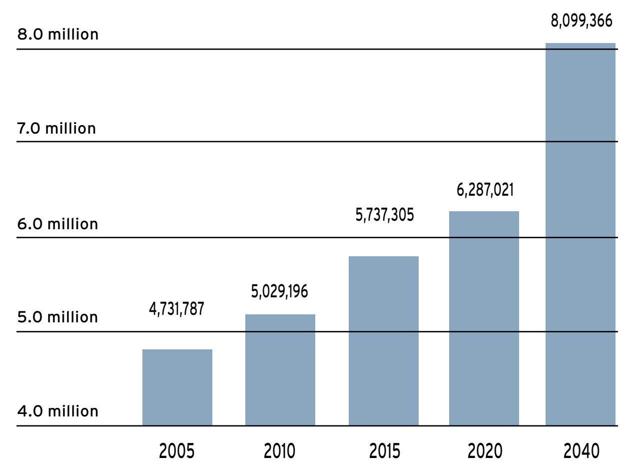


Figure 5: Colorado Preliminary Population Forecast
Source: Colorado Demography Office[5]

The average U.S. home today is nearly 50% larger than the average home in 1975, and the average U.S. household owns 23 consumer electronic products.

Colorado's electric power usage has grown steadily. In 1990, total Colorado residential, commercial, and industrial electric consumption was almost 31,000 gigawatt-hours (GWh). By 2007, DOE Energy Information Administration (EIA) data showed that consumption had increased by 67 percent, to more than 51,000 GWh. Given the increasing electrification of an energy-hungry digital economy, typified by the growth in plug loads (such as computers, photocopiers and servers in commercial buildings) and the increased penetration of residential air conditioning, growth in electricity consumption has outpaced the population growth rate. According to the Edison Electric Institute, the average U.S. home today is nearly 50% larger than the average home in 1975, and the average U.S. household owns 23 consumer electronic products.

Colorado might be in worse shape, was it not for the fact that less than one-fifth of the state's households use electricity as the main energy source for home heating. According to PSCo, the company's average growth in electric sales from 1997 to 2008 was 2.6 percent per year. Because of more ambitious energy efficiency programs and a slowdown in the economy, utilities have projected the future electric growth rate to be less than it has been historically. Of course, this can change.

The modeling analysis conducted a high load scenario of 3 percent to test key sensitivities. The projected growth rate was developed using Colorado generating utilities' high load forecasts filed with the CPWG. The CPWG is using the load forecast data as an input into the development of a 20-year conceptual transmission planning analysis. Using Colorado utility data, the annual load requirements projected to 2050 are shown in Figures 6 and 7.

The model used the 1.7 percent load forecast and built the least-cost electric power generation portfolio to meet the end users' energy demand over the planning horizon of 45 years, given the cost and performance of each generating technology, including their emission rates. The emission rates of existing fossil fuel-generating plants are based on EPA data. The blue line on Figure 8 represents where Colorado was headed before implementation of the HB07-1037 policy that established DSM goals for Colorado's two IOUs. Since the DSM goals apply only to IOUs, and since the goals are not as aggressive as leading

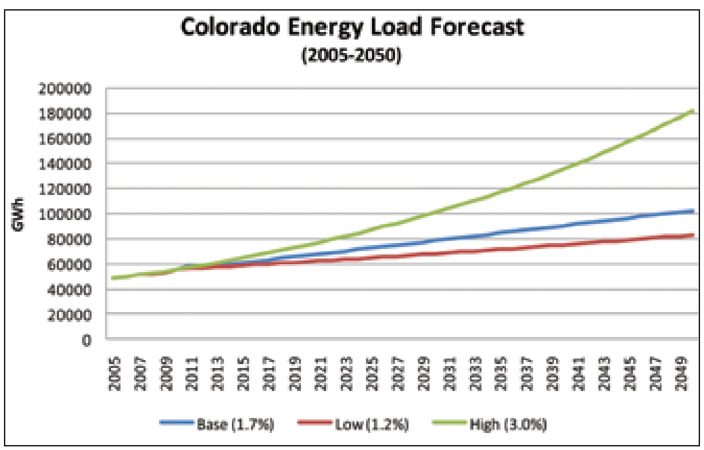


Figure 6: Colorado Energy Load Forecast

Source: STAR Report's Power Sector Climate Action Plan Scenario Analysis[6]

Colorado Energy Forecast (GWh)					
Year	Base (1.7%)	High (3.0%)	Year	Base (1.7%)	High (3.0%)
2005	48,353	48,353	2029	77,370	97,925
2008	52,571	52,571	2032	80,947	107,006
2011	59,223	57,521	2035	84,524	116,928
2014	59,986	62,855	2038	88,101	127,770
2017	63,226	68,683	2041	91,678	139,618
2020	66,661	75,052	2044	95,256	152,565
2023	70,215	82,011	2047	98,833	166,711
2026	73,792	89,616	2050	102,410	182,170

Figure 7: Colorado Energy Load Forecast

Source: STAR Report's Power Sector Climate Action Plan Scenario Analysis[7] utility-sponsored DSM programs in the nation, the influence of current DSM policies, represented by the red line on the chart, shows a disappointingly small reduction of Colorado's projected electric power CO_2 emissions. In contrast, a large amount of CO_2 reduction was obtained when the model entered the influence of Colorado's RES, and the modeled coal-fired generation retirement scenario which also included the retirement of 900 MW of coal-fired generation pursuant to HB10-1365.

The Model Selects the Lowest Cost Generation Option after Meeting RES, DSM, and CAP Goals

The green line in Figure 8 represents the CO_2 emission profile of the Colorado power sector, taking into consideration the effects of IOUs' DSM requirements plus the RES requirements for both IOUs and non-IOUs. The model then is directed to select generation with the lowest net present value to fill the gap between the green line (the reference scenario) and the purple line (the CAP goal). In other words, the model used a rule-based constraint to capture the Colorado RES and DSM laws and the CAP goals to the year 2050. After applying these constraints, the model selected new generation plants based upon the lowest-cost option while considering the carbon intensity of each technology to fulfill these rules and meet both the load growth obligation and the CAP goals.

Fuel Prices

The model used natural gas and coal price forecasts recently filed by PSCo in the PUC's review of HB10-1365 (the Clean Air-Clean Jobs Act). The natural gas price forecast was tested against various sources and scenarios to ensure it was reasonable and to identify key sensitivities. The modeling analysis incorporates gas and coal cost prices to the year 2050. When forecasting the future cost of any fossil fuel out 40 years, the confidence interval on the projection is reduced for each succeeding year. Many complex issues are involved in determining the cost of fuels. They include, but are not limited to, supply, demand, and assumptions regarding incorporation of externalities into the price. The outcome of electric power models are predicated on the assumptions that have been made about future costs of coal and natural gas and how quickly they may escalate. In previous decades, for example, coal costs often were dominated by long-term coal contracts, and these costs remained relatively stable. In recent years, however, long-term coal contracts for electric power generation in Colorado have been expiring and have shorter terms. Many coal purchases now are under contracts that last only one to three years. In recent years, Colorado coal costs have increased more rapidly than in the previous decade. The STAR modeling did not incorporate recent escalations in coal costs and project them forward. The STAR modeling used what may turn out to be low future coal costs that were presented by PSCo in the company's most recent filings at the PUC. If coal costs increase faster than indicated by PSCo (and relied upon in STAR's modeling run), additional benefits of retiring coal plants would be evident.

Figure 9 shows PSCo's most recent natural gas price forecast used in the model for the scenario analysis, compared to the most recent forecast from the EIA. Note that EIA projections go out only to the year 2035. Problems in calibrating these future coal and natural gas costs have been complicated by PSCo's use of nominal dollars and EIA's use of real dollars.

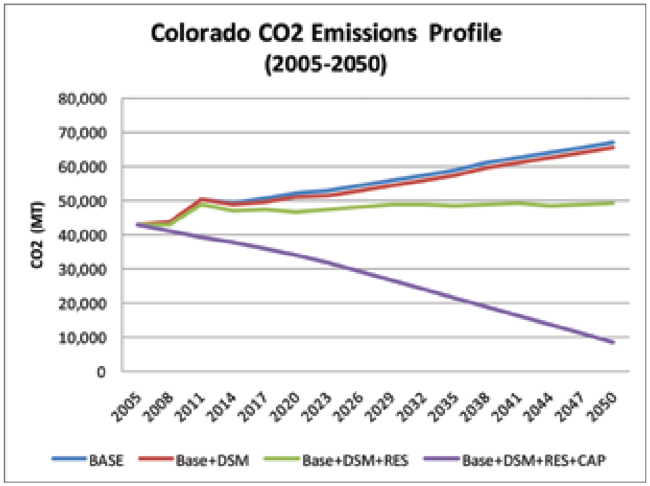


Figure 8: Colorado CO2 Emissions Profile

Source: STAR Report's Power Sector Climate Action Plan Scenario Analysis[8]

GEO used what it considered to be the most reliable, published data from a variety of sources (including the FERC, the EIA's National Energy Modeling System, the National Renewable Energy Laboratory, and Colorado utilities' regulatory filings).

Figure 10 shows comparisons between gas prices and coal prices, once again using data sourced from PSCo's recent filings at the PUC in the Clean Air-Clean Jobs Act docket.

Supply-side Power Generation Alternatives

The model included a wide range of potential supply-side alternatives. The GEO modeling analysis did not supply its own assumptions of capital cost numbers. GEO used what it considered to be the most reliable, published data from a variety of sources (including the FERC, the EIA's National Energy Modeling System, the National Renewable Energy Laboratory, and Colorado utilities' regulatory filings). The resource deck employed in the modeling is shown as Figure 11. Despite a careful selection of data and analysis, disagreements with the selection of the data are bound to exist. Opinions and experiences differ, sometimes widely, regarding capital cost assumptions. For example, certain capital cost assumptions for nuclear power and advanced combined cycle plants with 90 percent carbon capture and sequestration may appear to some to be low. Another example might be that certain capital cost numbers for solar power may appear to be too high. Although GEO would have appreciated seeing the results of running separate sensitivities on a range of capital costs for generation resources, this capability was outside the limitations of the STAR modeling exercise.

Renewable resources were evaluated and specific constraints or assumptions were applied to these technologies to make them most relevant to Colorado. Wind resources had assumed capacity factors imposed for each of the relevant GDAs. For system operational reasons, a wind

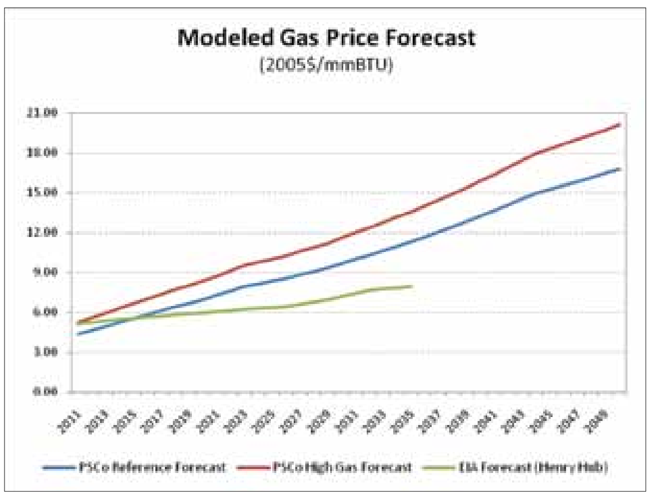


Figure 9: GEO Modeled Gas Price Forecast

Source: STAR Report's Power Sector Climate Action Plan Scenario Analysis[9]

Modeled Fuel Prices (2005 $/mmBTU)

	Fuel Prices		High Gas (+20%)
Year	Coal	Gas	Gas
2005	$1.18	$8.90	$8.90
2008	$1.24	$8.86	$8.86
2011	$1.64	$4.35	$5.22
2014	$1.68	$5.23	$6.28
2017	$1.80	$6.14	$7.37
2020	$1.84	$6.95	$8.34
2023	$1.92	$7.95	$9.54
2026	$1.93	$8.55	$10.26
2029	$1.84	$9.35	$11.21
2032	$1.96	$10.31	$12.37
2035	$2.04	$11.31	$13.57
2038	$2.14	$12.42	$14.91
2041	$2.44	$13.63	$16.36
2044	$2.58	$14.97	$17.96
2047	$2.73	$15.84	$19.01
2050	$2.89	$16.76	$20.11

Figure 10: GEO Modeled Fuel Prices Forecast

Source: STAR Report Power Sector Climate Action Plan Scenario Analysis[10]

Modeled Power Generation Technology##	Capital Cost# ($/kW)	Life	Heat Rate# (Btu/kWh)	AF (%)	VAROM ($/MWh)	FXDOM ($/kW/yr)	Emission Rates#		
							CO2 (lb/MWh) Output	NOx (lb/MWh) Output	SO2 (lb/MWh) Output
Biomass CC***	2,696	30	10,283	80	2.99	45.04	n/a	n/a	n/a
PC with 50% CCS**	3,366	50	11,343	80	10.58	46.21	1,167	0.3730	0.6191
Com3 - Xcel Energy*	2,020	50	8,672	85	3.06	15.64	2,159	0.0000	0.0000
Coal IGCC with 50% CCS*	3,317	50	10,202	80	3.05	17.14	1,048	0.4270	0.7048
Existing Bit Coal Steam	n/a	45	10,618	80	2.78	15.64	2,159	3.8953	2.3873
Existing Sub Bit Coal Steam	n/a	45	10,474	80	2.78	15.64	2,143	3.1810	3.7048
Existing DSF Steam	n/a	45	12,916	85	0.52	0.86	2,000	2.4683	0.1952
Existing Diesel IC	n/a	45	12,916	85	8.89	0.86	2,000	2.4683	0.1952
Geothermal***	3,156	45	10,283	90	22.88	16.71	n/a	n/a	n/a
Existing Hydro	n/a	50	10,283	27	4.48	14.20	n/a	n/a	n/a
Existing Hydro PS	n/a	50	3,754	83	2.65	16.71	n/a	n/a	n/a
Adv CT***	735	30	8,553	94	2.83	8.89	921	0.0873	n/a
Adv CC***	764	30	7,281	92	3.09	9.42	865	0.0714	n/a
Existing CC	n/a	30	7,399	92	0.49	15.75	881	0.1532	n/a
CC**	708	30	7,463	92	2.81	13.19	869	0.3413	n/a
Existing CT	n/a	30	10,525	94	0.10	6.51	1,278	0.5683	n/a
CT***	613	30	10,459	94	7.95	4.31	1,246	0.5175	n/a
Gas_CC with 90% CCS***	1,412	30	7,952	92	2.93	19.95	86	0.0794	n/a
Existing Gas Steam	n/a	45	13,390	85	0.52	0.86	1,587	2.4151	n/a
Adv Nuclear#+	4,245	50	10,512	90	0.60	58.00	n/a	n/a	n/a
PV_Central***	3,830	30	10,283	n/a	n/a	8.96	n/a	n/a	n/a
Solar_CSP** (2014)	3,500	30	10,283	n/a	n/a	43.55	n/a	n/a	n/a
Wind (Include PTC)***	1,690	25	10,283	n/a	n/a	23.24	n/a	n/a	n/a
Coal Based Gen. Imports#	-	-	-	-	-	-	2,159	-	-
Gas Based Gen. Imports#	-	-	-	-	-	-	881	-	-

Notes:

CT = Combustion Turbine & CC = Combined Cycle
PC = Pulverized Coal
IGCC = Integrated Gasification Combined Cycle; CCS = Carbon Capture & Sequestration
Com3 = Pulverized coal unit by Xcel Energy with no SO2 and NOx impact (net of other 2 units)
PS = Pumped Storage Hydro Facility
AF = Availability Factor
Heat Rate# = Renewables' heat rates are an equivalent proxy heat rate
Capital Cost# = Updated capital costs include transmission interconnection and delivery costs. Costs (2005$)
Emission Rates# = Source of existing power plants emissions is EPA-ETS (Emission Tracking System)
Imports# = imports are transmission constrained at 5,100 GWh per year
##Sources data from DOE/EIA or EPA-NM or as noted by * from other sources
#+ FERC document considering EPRI and other sources.
*Xcel Energy = Operates as Public Service Company of Colorado - 2007 Resource Plan & HB-1365 Case.
**EPRI
***NREL
VAROM = Variable O&M, FXDOM = Fixed O&M

Figure 11: GEO-Modeled Generation Technology Parameters

Source: STAR Report Power Sector Climate Action Plan Scenario Analysis[11]

penetration of approximately 33 percent was assumed up to 2035, moving upward to a maximum of 45 percent penetration by 2050. Accordingly, the maximum installed wind resource was constrained to reach approximately 10 GW by 2035 and 16 GW by 2050. The data for photovoltaics is a blend of PV technologies (flat panel, single axis tracking, dual axis tracking, and concentrated PV). The data for concentrated solar power (CSP) is a blend of technologies (power tower and trough systems).

Concentrated solar power was assumed to have a maximum installed limit of 6 GW. This limitation is primarily due to anticipation of possible long-term transmission constraints on the ability to transfer such a substantial amount of power from the San Luis Valley.

The Model's Coal Retirement Scenario

A coal plant retirement scenario was modeled to evaluate the effects of a scheduled retirement of Colorado's fleet of aging coal-fired power plants on levels of emissions (including CO_2, sulfur oxide (SOx), and nitrogen oxide (NOx). Colorado's 33 operating coal-fired power units at 14 locations have a nameplate capacity total of 5,308 MW. The analysis modeled retirement of Colorado's existing fleet of coal-fired power plants that will be 45 years or older starting in 2017. The analysis used Figure 12, which lists Colorado's coal-fired generating stations' commercial operation dates and the year the plants will reach age 45 (2017 and beyond).

The model first develops a reference case calibrated to the base year 2005. The year 2005 is used as the starting point because it is the base year for the CAP's CO_2 reduction goals. Generation facilities were used within the model to meet the load requirements after they were decremented by the DSM impact. Renewable resources begin the planning period with their 2005 share of generation of about 1.5 percent of the state load. Renewable generation is then added annually to meet the intended minimum RES targets for IOUs and non-IOUs in 2020. Note that as the cost for renewables (particularly solar) declines compared to thermal (fossil) alternatives, the model adds more incremental renewables than the minimum required for RES compliance.

Colorado Coal-Fired Power Plants Subject to Retirement - Vintage of 45 yrs. or higher (2017 and Beyond)#

Plant	Unit	Commercial Operation	2011	2014	2017	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Cameo*	1	1957	-	22	-	-	-	-	-	-	-	-	-	-	-	-
Cameo*	2	1960	-	44	-	-	-	-	-	-	-	-	-	-	-	-
Cherokee	1	1957	-	-	125	-	-	-	-	-	-	-	-	-	-	-
Cherokee	2	1959	-	-	125	-	-	-	-	-	-	-	-	-	-	-
Cherokee	3	1962	-	-	170	-	-	-	-	-	-	-	-	-	-	-
Cherokee	4	1968	-	-	381	-	-	-	-	-	-	-	-	-	-	-
Hayden	1	1965	-	-	143	-	-	-	-	-	-	-	-	-	-	-
Hayden	2	1976	-	-	-	-	103	-	-	-	-	-	-	-	-	-
Martin Drake	5	1962	-	-	50	-	-	-	-	-	-	-	-	-	-	-
Martin Drake	6	1968	-	-	75	-	-	-	-	-	-	-	-	-	-	-
Martin Drake	7	1974	-	-	-	132	-	-	-	-	-	-	-	-	-	-
Nucla	1	1959	-	-	-	-	-	-	-	-	-	12	-	-	-	-
Nucla	2	1959	-	-	-	-	-	-	-	-	-	12	-	-	-	-
Nucla	3	1959	-	-	-	-	-	-	-	-	-	12	-	-	-	-
Nucla	ST4	1991	-	-	-	-	-	-	-	-	-	79	-	-	-	-
Valmont	5	1964	-	-	192	-	-	-	-	-	-	-	-	-	-	-
Arapahoe*	3	1951	-	48	-	-	-	-	-	-	-	-	-	-	-	-
Arapahoe*	4	1955	-	112	-	-	-	-	-	-	-	-	-	-	-	-
Comanche	1	1973	-	-	-	383	-	-	-	-	-	-	-	-	-	-
Comanche	2	1975	-	-	-	-	396	-	-	-	-	-	-	-	-	-
Comanche	3	2010	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Comanche	3	2010	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Craig	1	1980	-	-	-	-	-	80	-	-	-	-	-	-	-	-
Craig	1	1980	-	-	-	-	-	45	-	-	-	-	-	-	-	-
Craig	1	1980	-	-	-	-	-	107	-	-	-	-	-	-	-	-
Craig	2	1979	-	-	-	-	-	80	-	-	-	-	-	-	-	-
Craig	2	1979	-	-	-	-	-	45	-	-	-	-	-	-	-	-
Craig	2	1979	-	-	-	-	-	107	-	-	-	-	-	-	-	-
Craig	3	1984	-	-	-	-	-	-	-	463	-	-	-	-	-	-
Pawnee	1	1981	-	-	-	-	-	-	552	-	-	-	-	-	-	-
Rawhide	ST1	1984	-	-	-	-	-	-	-	294	-	-	-	-	-	-
Ray D Nixon	ST1	1980	-	-	-	-	-	207	-	-	-	-	-	-	-	-
Modeled Potential Retirement (MW)			-	226	1,261	515	499	671	552	757	-	114	-	-	-	-

Notes:

* Scheduled by Xcel to retire prior to 2017.

\# Retirement/Repowering begins at 2017 even if the age of power plants are higher than 45 years prior to 2017.

Figure 12: Colorado Coal Plants Modeled for Retirement

Source: STAR Report's Power Sector Climate Action Plan Scenario Analysis

Notes: Units with more than one owner are listed by owner's capacity share ownership. ST stands for steam unit 1 or 4. Units retire once they become older than 45. For example, if a unit reaches 45 in 2020, it will retire in 2021. Since the data was modeled in three-year increments, the unit will be shown in 2023.

The model uses coal generation to its full extent to provide the bulk of the load requirements from operation of all coal-fired power plants, including the Comanche 3 coal-fired plant that was placed in service in 2010. The model also uses all existing gas generation capacity and adds gas-fired generation capacity as needed to meet the forecasted load during the planning period. Model run results use natural gas for all nonrenewable incremental generation additions. No conventional coal without carbon capture and sequestration is available to the model since that would, by definition, defeat the CO_2 reduction metric that is a key parameter for the modeling.

Figure 13 depicts the generation increments added for two primary scenarios. The first scenario is the reference case that adjusts a base case to incorporate existing DSM and RES policies. The second scenario applies the CAP requirements to the reference case. The contribution of each element of demand-side and supply-side resource for the three primary scenarios of base case, base case plus DSM, and base case plus DSM plus RES are shown under the designation "R" in Figure 14. The figure identifies the relevant contribution from each resource and how it changes between 2020, 2030 and 2050 with the reference case subject to high load (HL), high gas (HG), the retirement scenario (RT), or the combination of all three.

How to Read the Model's Bar Charts

When reviewing the bar charts, read the legend, then apply the colors to the stacked bars. For example, the Reference Case + CAP scenario in 2050, Wind (2005) is at the top, followed by Wind – All Other GDAs, Wind - GDA 1 & 8, Wind - GDA 2, Solar_CSP, and so on. The last item is Biomass_CC.

Emissions and Cost Impact to Colorado

Important conclusions of the analysis are results that quantify the effects of achieving the CAP goals. The model results demonstrate that, under some scenarios such as high load growth and high gas prices, total emissions of CO_2 will actually increase over 2005 levels. The most attractive scenario to

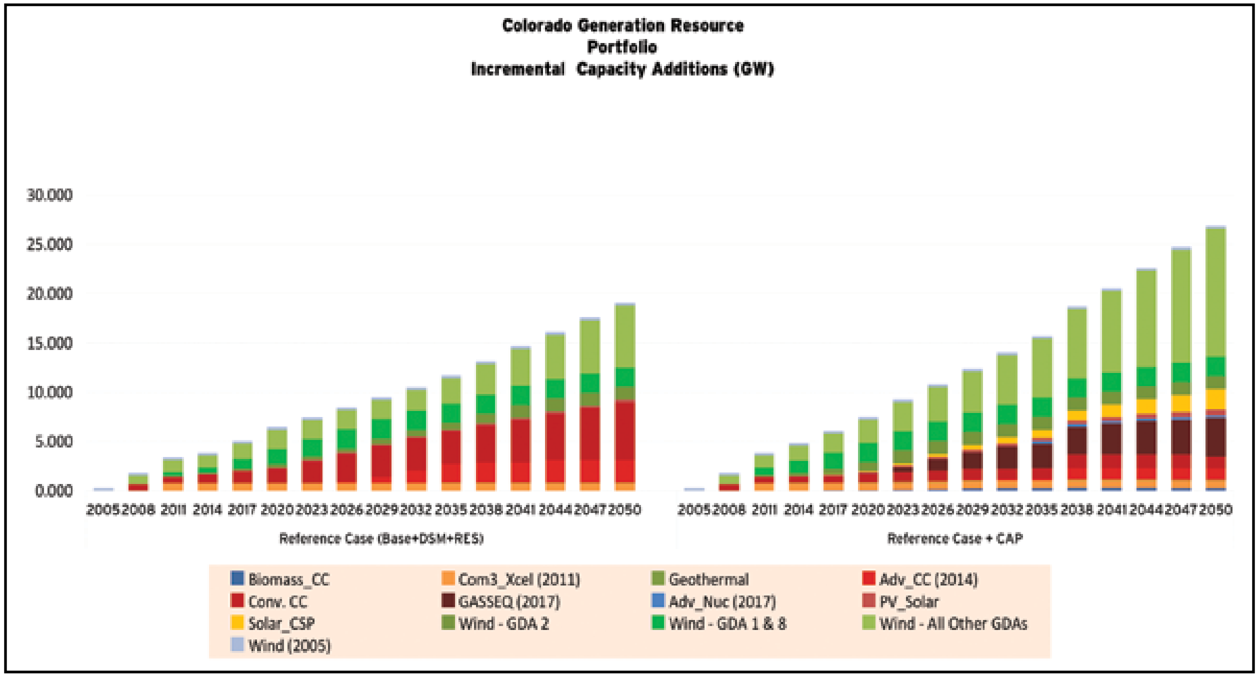


Figure 13: Colorado Generation Resource Portfolio

Source: STAR Report Power Sector Climate Action Plan Scenario Analysis[12]

If customers and utilities intend to save billions in expenditures for generation, Colorado must aggressively pursue demand-side measures to help dampen load growth.

reduce overall CO_2 emissions is the one that starts with the base case, adds the benefit of DSM, then introduces the benefits of RES and CAP compliance, as well as the benefits of coal plant retirements beginning in 2017 until they reach age 45. As shown in Figure 15, this last scenario puts Colorado closest to the CAP goals. The most viable alternatives to reach the CAP targets are to deploy DSM and set a schedule for retiring coal-fired generation plants when they reach the age of 45. An aggressive commitment to DSM would also simultaneously add the benefit of SOx and NOx emission reductions. A review of Figure 16, depicting discounted total system costs, provides strong evidence that, if customers and utilities intend to save billions in expenditures for generation, Colorado must aggressively pursue demand-side measures to help dampen load growth.

Implications of the Modeling Regarding Transmission

The modeling clearly indicates that unless a much greater commitment to demand-side measures is instituted, major supply-side capacity additions, in the form of renewable energy and natural gas, must be brought on line to meet load growth and CAP goals. Transmission implications for wind and solar resources are quite apparent, given that Colorado's renewable energy generation development areas are distant from the load centers. Transmission implications for natural gas generation may be less, and are not analyzed in this report.

Technology/Scenario	2020 CAPACITY PORTFOLIO (GW)				2030 CAPACITY PORTFOLIO (GW)				2050 CAPACITY PORTFOLIO (GW)			
	R	R+HL	R+RT+HL	R+RT+HL+HG	R	R+HL	R+RT+HL	R+RT+HL+HG	R	R+HL	R+RT+HL	R+RT+HL+HG
Biomass_CC	0.059	0.059	0.059	0.059	0.240	0.240	0.240	0.240	0.260	0.260	0.260	0.260
Com3_Xcel (2011)	0.750	0.750	0.750	0.750	0.750	0.750	0.750	0.750	0.750	0.750	0.750	0.750
Geothermal	0.020	0.020	0.013	0.020	0.020	0.020	0.020	0.020	0.040	0.040	0.040	0.040
Adv_CC (2014)	0.000	0.000	0.000	0.315	0.151	0.000	1.916	1.545	1.209	0.000	1.916	1.436
Conv. CC	2.304	2.304	4.538	3.598	1.033	3.270	5.055	4.871	1.189	6.053	8.277	9.895
GASSEQ (2017)	0.503	0.503	0.000	0.000	1.710	3.865	3.488	0.000	3.942	14.408	14.202	6.192
Adv_Nuc (2017)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	3.060	0.270	4.283	4.455	8.351
PV_Solar	0.174	0.174	0.171	0.202	0.255	0.259	0.258	0.296	0.550	0.548	0.548	0.659
Solar_CSP	0.117	0.117	0.117	0.709	0.480	0.480	0.480	1.877	2.104	2.104	2.104	6.000
Wind - GDA 2	0.993	0.993	0.849	1.280	1.280	1.280	1.280	1.280	1.280	1.280	1.280	1.280
Wind - GDA 1 & 8	2.000	2.000	2.000	2.000	2.000	2.000	2.000	2.000	2.000	2.000	2.000	2.000
Wind - All Other GDAs	2.365	2.365	2.365	2.365	4.193	4.193	4.193	4.193	13.000	13.000	13.000	13.000
Wind (2005)	0.264	0.264	0.264	0.264	0.264	0.264	0.264	0.264	0.264	0.264	0.264	0.264
Total Inc. Capacity Addition	9.547	9.547	11.125	11.561	12.376	16.620	19.944	20.395	26.857	44.990	49.096	50.126

Figure 14: Resource Mix of carbon Constrained Scenarios

Source: STAR Report Power Sector Climate Action Plan Scenario Analysis[13]

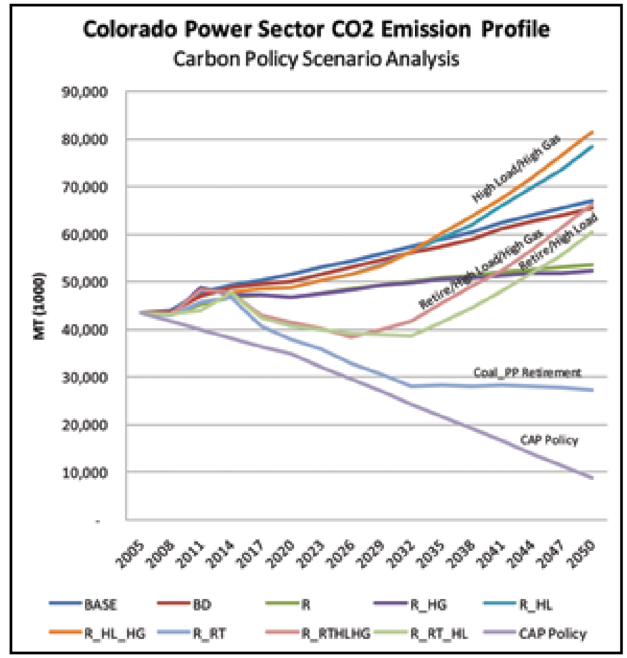
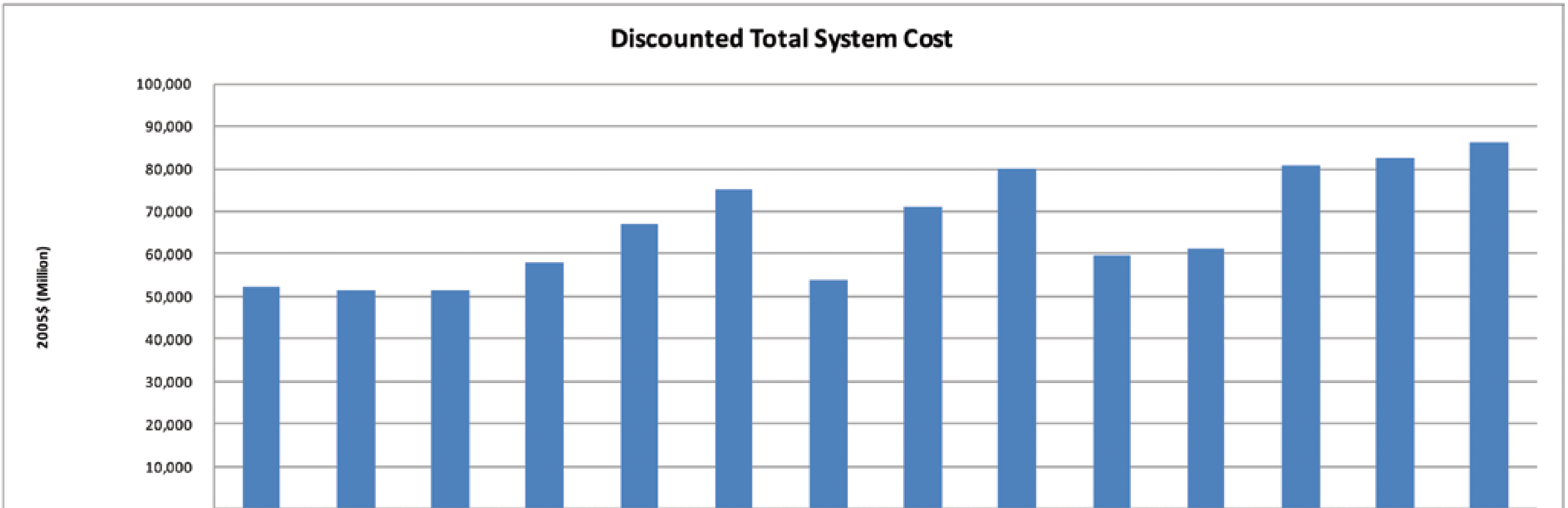


Figure 15: Colorado Power Sector CO2 Emission Profile

Source: Power Sector Climate Action Plan Scenario Analysis[14]



	BASE	BD	R	R_RT	R_HL	R_RT_HL	R_HG	R_HL_HG	R_RTHLHG	RC	RC_RT	RC_HL	RC_RT_HL	RC_RHLHG
Scenarios System Cost	52,363	51,391	51,488	58,027	67,102	75,100	53,986	70,925	80,067	59,473	61,003	80,886	82,462	86,361

Scenario Descriptions	
Base	Business as Unsual under 1.7% Load Growth (No DSM or RES)
BD	Base with DSM
R	Reference case [Base + DSM + RES (30% IOUs and 10% non-IOUs by 2020)]
RC	Reference Case with Colorado Climate Action Plan Goals (CAP at 20%, 40%, and 80% below 2005 CO2 level by 2020, 2030, and 2050)
RC_HL	Reference Case with CAP, and High Load Growth (3%)
RC_RHLHG	Reference Case with CAP, Retirement, High Load Growth, and High Gas Cost
RC_RT	Reference Case with CAP, and Retirement
RC_RT_HL	Reference Case with CAP, Retirement, and High Load Growth
R_HG	Reference Case with High Gas Cost (+20%)
R_HL	Reference Case with High Load Growth (3%)
R_HL_HG	Reference Case with High Gas Cost and High Load Growth
R_RT	Reference Case with Coal-Fired Power Plants Vintage 45 yrs. or Higher Retire Beginning 2017
R_RTHLHG	Reference Case with Retirement and High Load Growth and High Gas Cost
R_RT_HL	Reference Case with Retirement and High Load Growth

Figure 16: Discounted Total System Cost

Source: STAR Report Power Sector Climate Action Plan Scenario Analysis[15]

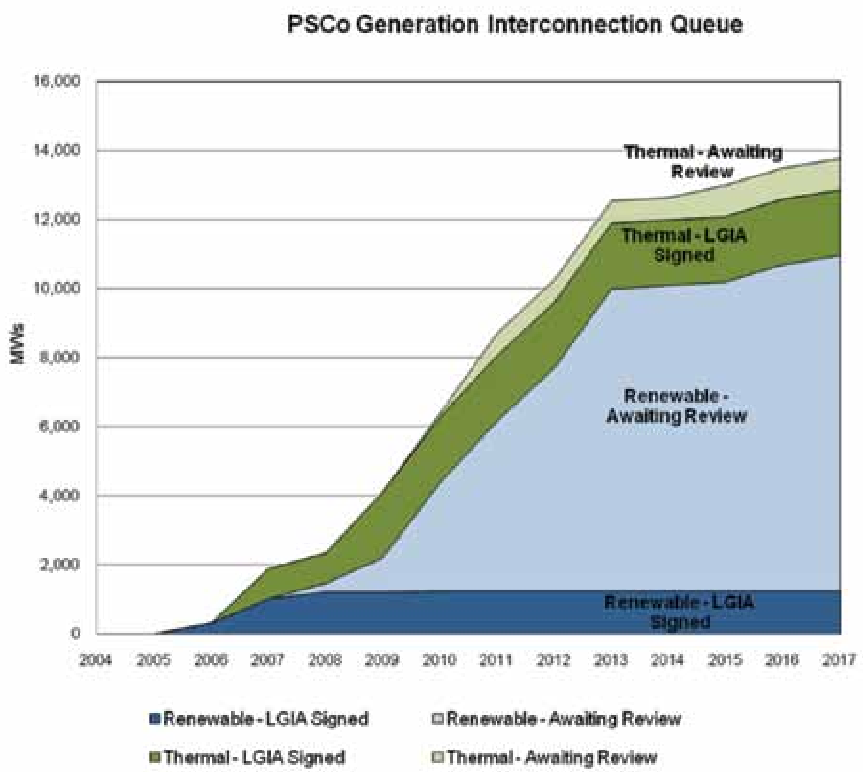
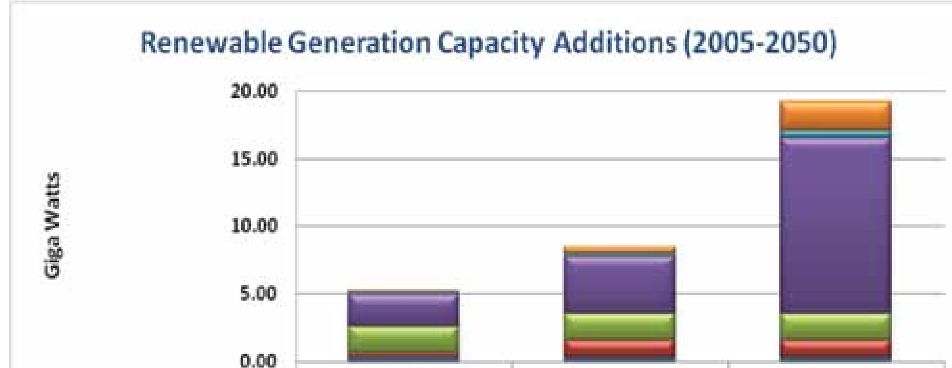


Figure 17: PSCo Generation Interconnection Queue
Source: ION Consulting analysis of OASIS Queue Requests[16]



	2020	2030	2050
Solar CSP	0.12	0.48	2.10
Solar PV	0.17	0.26	0.55
New Wind (All Other GDAs)	2.37	4.19	13.00
New Wind (GDA 1&8)	2.00	2.00	2.00
New Wind (GDA 2)	0.35	1.28	1.28
Wind (2005)	0.26	0.26	0.26

Figure 18: Renewable Generation Capacity Additions (2005–2050)
Source: STAR Report Power Sector Climate Action Plan Scenario Analysis[17]

Colorado electric power system planners continually review congestion and constraints on the state's transmission system. Thermal and renewable developers have requested nearly 14,000 MW of transmission access on PSCo's system. Approximately 100 generators have requested access to the transmission before 2016 as part of their development process. While many of these process may not be developed due to economic, technical, demand, and other reasons, available transmission capability is one of the most significant obstacles developers encounter. After independent power producers request transmission service, they must then wait for a large generator interconnection agreement (LGIA) to be signed, which further adds to their uncertainty. The status of the 14,000 MW of requested transmission is shown in Figure 17.

The GEO modeling analysis identifies a broad path forward for Colorado's electricity sector that will operate in a less carbon-intensive environment. The analysis quantifies the expected sources of generation and provides details on variables such as capital cost and emissions of CO_2, SOx, and NOx. It also quantifies the geographic implications to the state by modeling how much renewable capacity is likely to be generated in the state's GDAs. Figure 18 shows the renewable additions, selected on the basis of cost, by technology type and, in the case of wind power, by GDA. For reference, Figure 19 shows Colorado's GDAs and high-voltage transmission.

Twenty GW of new renewable capacity by 2050 will need to be interconnected to a transmission system. Today's transmission system is congested and challenged to meet existing requests from developers. A large fraction of

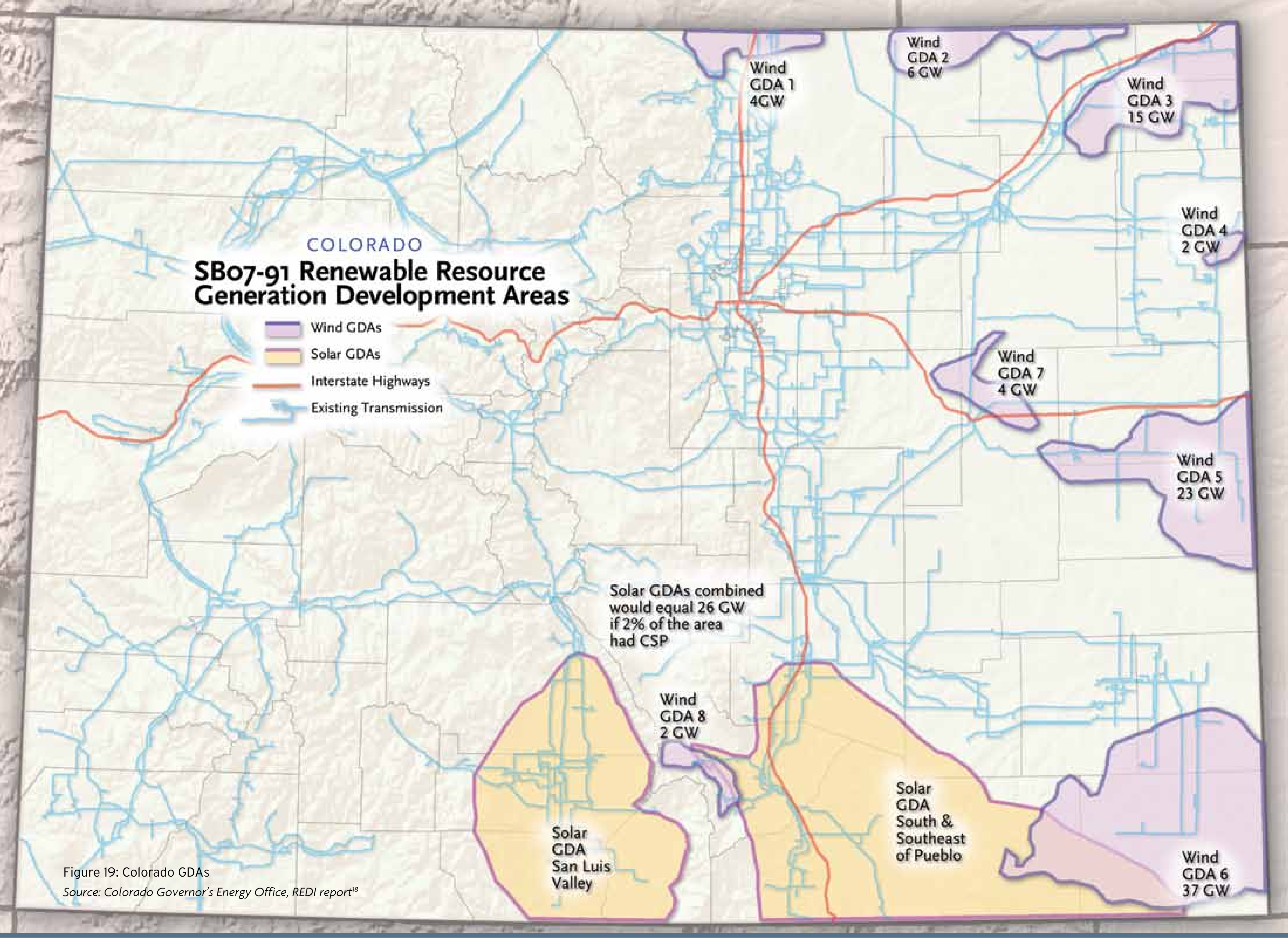


Figure 19: Colorado GDAs

Source: Colorado Governor's Energy Office, REDI report[18]

The GEO modeling analysis identifies a broad path forward for Colorado's electricity sector that will operate in a less carbon-intensive environment.

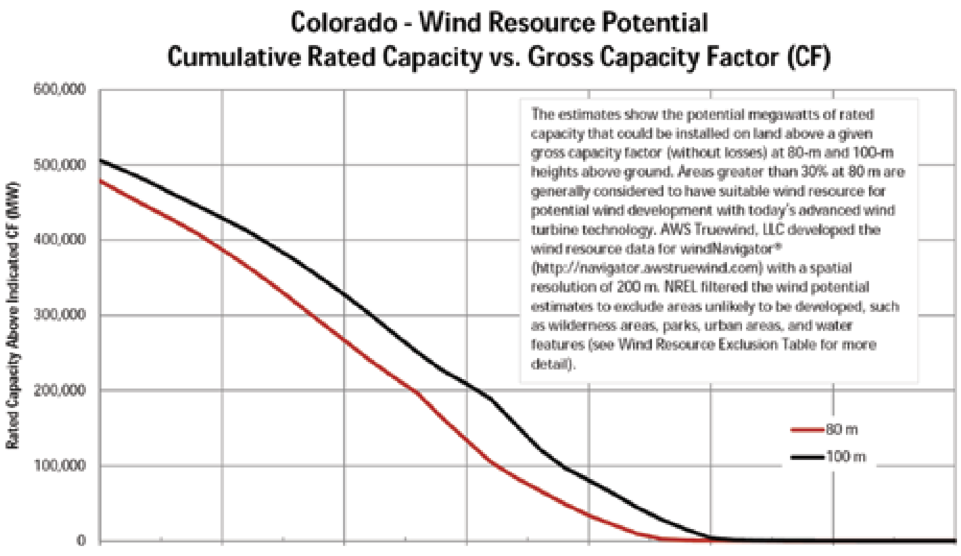


Figure 20: Colorado Wind Resource Potential

Source: National Renewable Energy Laboratory[19]

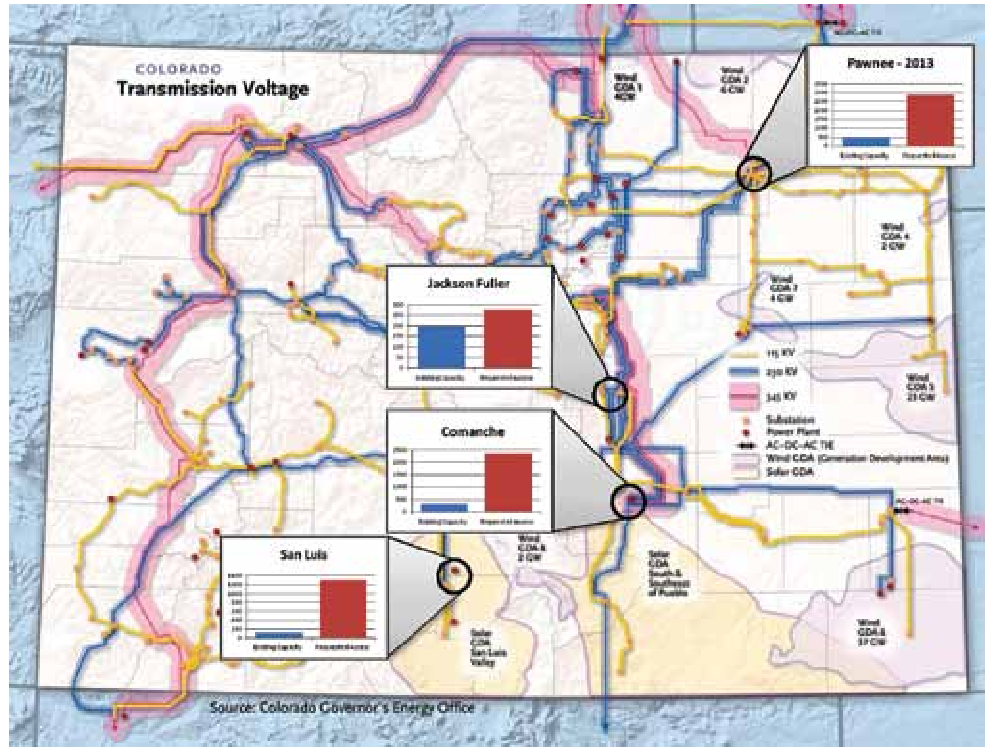


Figure 21: Colorado Substation Congestion

Source: Analysis of OASIS Queue Requests[20]

new renewable generation capacity is expected to be built in the GDAs and will need to pass through a system of lines and substations to reach the Front Range population centers.

Many key substations already are challenged to meet developer requests. Figure 21 indicates the available capacity and requested interconnections at four key substation locations on PSCo's system. Plans are under way to alleviate this problem, including installation of a new substation at a location known as Missile Site. To meet future generation requirements, more lines and substations will need to be built or upgraded to overcome existing congestion points.

2. Multiple Benefits of Demand-side Measures

REDI Review

Demand-side Measures

The REDI report emphasizes that Colorado needs to greatly increase investment in demand-side measures (energy efficiency, demand-side management, demand response, and conservation). The following are bundled and defined as demand-side measures: electric power conservation, energy efficiency, demand-side management, demand response, and distributed generation.

Impact on Generation and Transmission

The REDI report found that, depending on the scope and scale of the effort, demand-side measures could mitigate the need for new central power stations and new transmission. This is a challenge because customer behavior is not dependable, the demand loads are not under greater utility control, and population growth and increased electrification are taking place. As with all other strategies, some demand-side options are more cost-effective than others. Because demand-side measures involve less capital cost, they are generally more cost effective than the least expensive new central generation and transmission options. Demand-side options typically present less risk because they are small and modular. The recent trend in Colorado toward greater utility emphasis on sponsoring demand-side options is encouraging. Far greater emphasis on demand-side solutions will mitigate the need for new supply-side resources.

Overview

The nation's century-old electric grid consists of 9,200 electric generating units, with more than 1 million MW of capacity connected to more than 300,000 miles of transmission. The grid has served us well, providing a highly valued, reliable electricity supply. Although, according to the DOE, the grid is 99.97 percent reliable, outages and interruptions still occur that cost Americans $150 billion each year, or, if expressed on a per-capita basis, $500 per person per year.[21]

Opportunities centered on DSM, demand response (DR), and distributed generation (DG) present important opportunities to reduce the need for new utility-scale generation, and may, given certain scenarios, even reduce the need to expand the transmission infrastructure. The STAR modeling provided estimates of potential reduction in load growth from these three opportunities (Figure 22).

Demand-side Management

The American Council for an Energy Efficient Economy (ACEEE) is a nonprofit organization dedicated to advancing energy efficiency as a means of promoting economic prosperity,

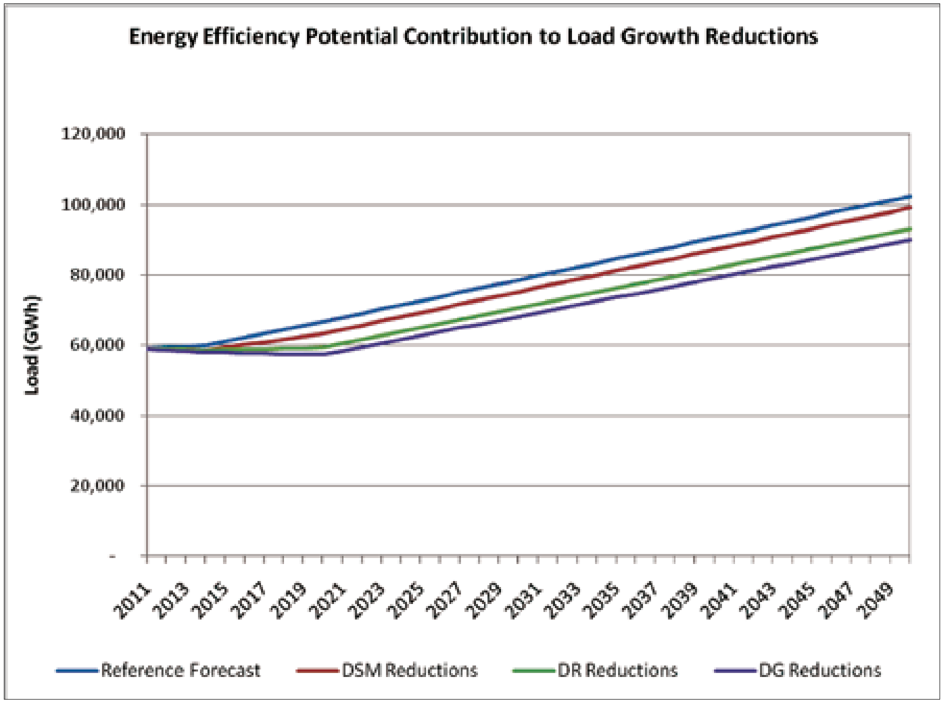


Figure 22: Energy Efficiency Potential Contribution to Load Growth Reductions

Source: STAR Report Power Sector Climate Action Plan Scenario Analysis[22]

Energy efficiency is by far the least costly energy resource option available for utility resource portfolios.

energy security, and environmental protection. The organization regularly updates the comparative costs and benefits of demand-side measures and supply-side resources. Their most recent report found that, "the energy efficiency programs from recent years in 14 states have utility CSE [cost of saved energy] ranging from $0.016 to $0.033 per kWh, with an average CSE of $0.025 per kWh. Given the range of costs, energy efficiency is by far the least costly energy resource option available for utility resource portfolios. Saving a kilowatt-hour through energy efficiency improvements is easily one-third or less the cost of any new source of electricity supply, whether conventional fossil fuel or renewable energy source. In addition, the results of this research suggest that the cost of energy efficiency has remained very consistent across states and over time."[23]

ACEEE produced a "scorecard"[24] on how Colorado and other states are moving forward with demand-side measures. The summary states that, "Colorado's utilities administer rapidly growing energy efficiency programs under a regulated structure with oversight by the PUC. The Consortium for Energy Efficiency reports electric efficiency budgets of $46.7 million and natural gas budgets of $13.3 million for 2009. According to the EIA, Colorado electric utilities saved 203,344 MWh in 2008. The PUC has authorized PSCo to expand its DSM programs, anticipated to reduce electricity use by 11.5% by 2020. HB07-1037 required the PUC to establish energy savings goals for gas and electric utilities and to give IOUs a financial incentive for implementing cost-effective efficiency programs. The utilities recover the program costs of the plans approved by the PUC by using tariff riders, which adjust customer bills. Colorado initiated natural gas decoupling in 2007 and implemented it in 2008. There are no decoupling options for electric utilities. The PUC has created incentives to reward utilities that create efficiency programs for electricity and/or natural gas."

The Southwest Energy Efficiency Project (SWEEP), a Boulder-based nonprofit organization, promotes greater energy efficiency in a six-state region that includes Arizona, Colorado, Nevada, New Mexico, Utah, and Wyoming. SWEEP has been effective in Colorado to help utility customers, businesses, utilities, local, and state government increase energy efficiency. SWEEP's website provides details on the extent of utility-sponsored demand side measures in Colorado.

Figure 23, produced by the Lawrence Berkeley Laboratory summarizes customer-funded utility demand- side measure programs in Colorado.[25]

Colorado's DSM Policies

In keeping with a national trend that began as early as 1980, the PUC required that modest DSM programs be introduced to PSCo customers in the early 1990s. However, as was also the trend about fifteen years ago, the DSM momentum trailed off, largely in anticipation of retail electric power competition. In part because Colorado did not restructure the electric power industry in the late 1990s, a moderate level of IOU-sponsored DSM programs was reintroduced.

Status of Colorado's Utility Energy Efficiency Activities

Feature	Summary
Utility landscape	Four regulated IOUs in the state: 1 large electric, 1 small electric, and 2 small gas utilities. The 54 small utilities (e.g., municipal, rural and cooperatives) carry approximately 40% of the state load.
Energy efficiency status	2007 the utilities commission set energy savings goals for all utilities and incentives for IOUs. PSCo and Black Hills targets are 0.53% of energy sales in 2009, increasing to 11.5% cumulative by 2020. Municipal, rural and cooperative utilities are also required to reduce emissions.
Ratepayer funding history	PSCo has been administering EE for a number of years; IOU programs now ramping up quickly since energy efficiency standards were established in 2007; Small but growing number of rural, co-op and municipal utility EE programs.
Ratepayer-funded budget for EE	2009 budget: $60M* (CEE 2009). 2008 electric EE program spending as a % of electric utility retail sales revenues: 0.39%.
Regulatory and Business Model	EE Program Administrator: Utilities Utility incentives structure: Performance incentive allows the two IOUs a profit on DSM expenditures for achieving minimum of 80% of savings goal in a year; capped at 20% of DSM expenditures. Decoupling: None for electric. Gas utilities only
Ratepayer program objectives	Least cost resource plan required by the PUC. For decoupled gas companies, objectives include societal benefits.
State Energy Office energy activity background	Pre-ARRA, the Governor initiated Climate Action Plan and pressed to advance the New Energy Economy

Figure 23: ACEEE State Policy Database; CEE (2009)

Source: ACEEE State Policy Database; CEE (2009)

Colorado's two IOUs (PSCo and BHE) are rate-regulated by the PUC. They serve approximately 60 percent of the state's electric customers. PSCo and BHE have legislative guidance and regulatory responsibilities to implement utility-sponsored demand-side measures. In contrast, the remaining 40 percent of the load is served by rural electric associations (REAs) and municipal utilities (munis). These utilities—with no current state legislative or PUC DSM requirements—offer varying degrees of demand-side measures. A popular program is retrofitting lighting in commercial buildings (Figure 24). For more information about Colorado's electric and gas utilities, see GEO's 96-page *2010 Colorado Utilities Report*.[26] The report provides a wealth of information, including details of demand-side and renewable energy programs offered by all Colorado electric and gas utilities.

In 2007, Colorado placed increased emphasis on utility-sponsored demand-side measures when the General Assembly passed House Bill HB 07-1037. The law required the PUC to establish minimum energy savings and demand reduction goals for IOUs to be acquired through energy efficiency, conservation, load management, and demand response programs. No requirements were placed on REAs or munis. The purpose of these requirements is to reduce the energy and capacity that the IOUs otherwise would have met through supply-side (power generation) resources. In 2007, in response to the new law, PSCo offered an enhanced DSM plan to its customers. With some modifications by the PUC, the plan was accepted. When the plan was applied in combination with the 2003 least-cost planning DSM requirements for the period 2009–2020, PSCo proposed to spend $738 million (2006 dollars) on more DSM programs to achieve 2,350 gigawatt-hours (GWh). This amounts to approximately 200 GWh per year of energy savings.[27] Similar DSM goals are being pursued at Black Hills Energy, albeit on a much smaller scale due to the size of Black Hills.

Distributed Generation

HB10-1001 (Colorado's Renewable Energy Standard)

On March 22, 2010, the governor signed HB10-1001 into law[28] which increased the state's RES. The law requires IOUs to generate at least 30 percent of their electricity from solar, wind, geothermal, biomass, new hydro, or recycled energy by 2020, and generate at least 3 percent of their retail sales from distributed generation, with half originating from on-site renewables. It also requires incremental implementation of solar installation certification standards to allow participation in utility and state incentive programs.[29]

Within the RES, DG includes retail distributed generation (RDG) and wholesale distributed generation (WDG). RDG is defined as an on-site renewable energy resource, interconnected to the grid and designed to provide electricity to serve customer load. RDG must be sized to supply no more than 120 percent of the average annual electricity consumption at a particular site. WDG is defined as a Colorado renewable energy resource with a nameplate rating of 30 MW or less that is not RDG.[30] As of October 2009, Colorado's 59 MW of installed PV ranks it third in the nation.[31] HB10-1001 is discussed in greater depth in Chapter 4.

Figure 25 shows the states with renewable portfolio standards that contain either solar or distributed generation provisions.

Figure 24: Photo by Matt McClain

HB10-1342 (Community Solar Gardens)

The Community Solar Gardens Act[32] supports development of some of the nation's first community solar programs. The law allows fractionally owned solar farms within an IOU service territory. This allows renters, homeowners without solar access, and businesses to own a portion of a solar farm. The legislation also directs the PUC to adopt rules under which this program will be managed. A solar garden is a solar farm of 2 MW capacity or smaller, owned by 10 or more customers, and located in the county where the co-owners reside. The solar

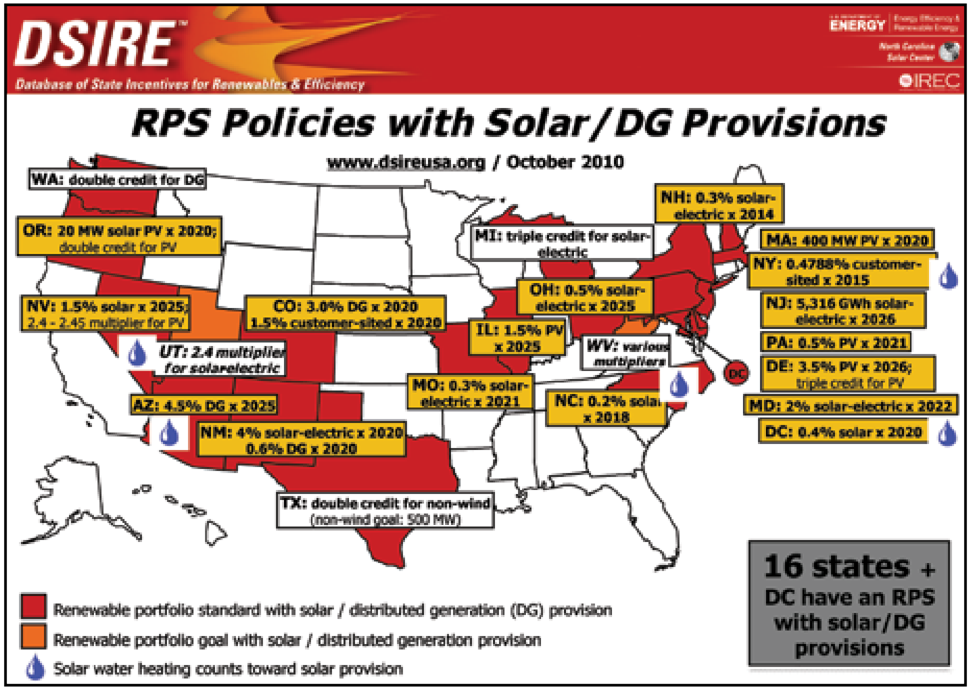


Figure 25: RPS Policies with Solar/DG Provisions

Source: DSIRE – Database of State Incentives for Renewables and Efficiency[33]

By using smart meters to measure and validate load reductions, the smart grid, and its ability to communicate load information to customers and utilities, brings conservation and energy efficiency into the 21st century.

garden concept was first introduced in Colorado by United Power, an REA located northeast of Denver. With seed money provided by the GEO, in May 2009 United Power[34] launched one of the first solar farms in the country. A second module was added in August 2010.

Opportunities with Demand-side Measures

Demand-side measures, along with use of smart grid technologies, have the benefit of mitigating the need for more costly and environmentally challenging generation. Introducing demand-side measures results in savings to electric customers, proven throughout the world to be effective over the past three decades. With the advent of smart grid technologies, the data measured by these technologies can provide for an ever-increasing quantification of reduction in load. The following demand-side measures are individually evaluated with respect to the smart grid, Colorado's smart grid activities, and estimates of demand reduction.

Energy Efficiency and the Smart Grid

By using smart meters to measure and validate load reductions, the smart grid, and its ability to communicate load information to customers and utilities, brings conservation and energy efficiency into the 21st century. The GEO commissioned a report prepared in June 2010 by the University of Colorado at Boulder that states, "A key benefit of smart grid is the ability to measure and verify energy efficiency savings. This verification of savings opens the door to an alternate business model, 'shared savings,' which has previously been limited in potential because of measurement and verification challenges. Shared savings programs are based on verified savings, not expenditures, which encourage the utilities to make cost-effective efficiency investments."[35] Although certain components of the smart grid– such as communications– may be challenging, great strides are being taken to address these challenges.

Demand Response

Demand response (DR) involves changing the time when customers use electric power to save on system costs, often using automated controls. More than 125 utilities across the United States are contracting with DR specialists to implement DR programs on a pay-for-performance basis.

- **Demand Response as a Peak Resource:** DR has long been an option for industrial and large commercial customers that participate in utility interruptible programs. The National Renewable Energy Laboratory's July 2010 conference paper, *Utilizing Load Response for Wind and Solar Integration and Power System Reliability*[36] states that, "while many DR programs have been successful, it remains a limited resource." Two recent reports issued by the FERC assess the current state of DR and offer the basis for a national plan for increasing its use: *A National Assessment of Demand Response Potential* (FERC, 2009)[37] and *National Action Plan on Demand Response (Draft)* (FERC, 2010).[38] FERC found current DR use to be significant, and the potential exists for even greater use. Current DR programs tap less than a quarter of the resource. FERC's assessment is important because it is influencing policy that potentially could result in reliability and market rule changes that increase the amount of DR.

- **Current Demand Response Programs:** According to the North American Electric Reliability Corporation's (NERC's) 2009 report, *Long-Term Reliability Assessment 2009-2018*,[39] participation in DR programs continues to grow, not only in magnitude, but also as a percentage of the total demand through the ten-year time frame. More than 32,000 MW of DR (both dispatchable and controllable) is currently being used to manage peak demand. As is shown in Figure 26, this number is projected to increase to more than 38,000 MW by 2018.

- **Demand Response and the Smart Grid:** Smart grid technologies harness the power of increasing computational power and information management to improve efficiency, consumer engagement, and advanced energy management capabilities within a utility's energy demand and delivery system. With the advent of smart grid technologies, DR has gained increased attention. By facilitating instantaneous communication, DR is one of the potential beneficiaries of a successful smart grid program. Spurred by the American Reinvestment and Recovery Act, "smart meter deployment is expected to reach a penetration of 48 percent of all meters converted by 2015," according to GTM Research.[40] As the smart grid evolves from smart meter replacements into an integrated communication network, utilities have an opportunity to inform customers about their load information using a real-time format and to allow customers to receive price signals to provide an incentive to use or shift loads to more optimum times. A reduction in load or demand forecast may reduce the need for generation. Note that some risk exists in relying too heavily upon DR for reducing load in the long term. For example, participating DR customers may opt out of the DR program, placing demand back onto the system and potentially requiring new utility investments.

- **Potential for Demand Response Programs:** FERC concludes that up to 188 GW of DR– nearly 20 percent of the nation's peak demand—could potentially be available by 2019 with full participation.[41] FERC calculates in Figure 27 that, in the mountain areas (which includes Colorado), a significant gap (in the range of 20 percent) exists between today's market and a full participation scenario. Dynamic pricing programs that use smart meter information represent a method to encourage full participation. However, these programs require regulatory changes, new tariffs, and other substantial, and often contentious, efforts.

- **Demand Response and Ancillary Services**: As described in an NREL report,[42] "Responsive loads are beginning to provide the fast ancillary services: regulation, spinning reserve, non-spin, supplemental operating reserve, and emergency response." It continues to be difficult for DR to provide regulation service, but it has potential for supplying contingency reserves.

- **Demand Response and Contingency Reserves:** NREL's report[42] also notes that providing contingency reserves (spinning, non-spinning, and supplemental operating reserves) is also attractive to some loads because the response duration is short (11 minutes for spin and non-spin on average in ISO markets) and the need for response is relatively infrequent (every few days on average). Smart grid advances in technology make the fast communications and control practical. Further support for using DR for contingency reserves is described in NREL's *Western Wind and*

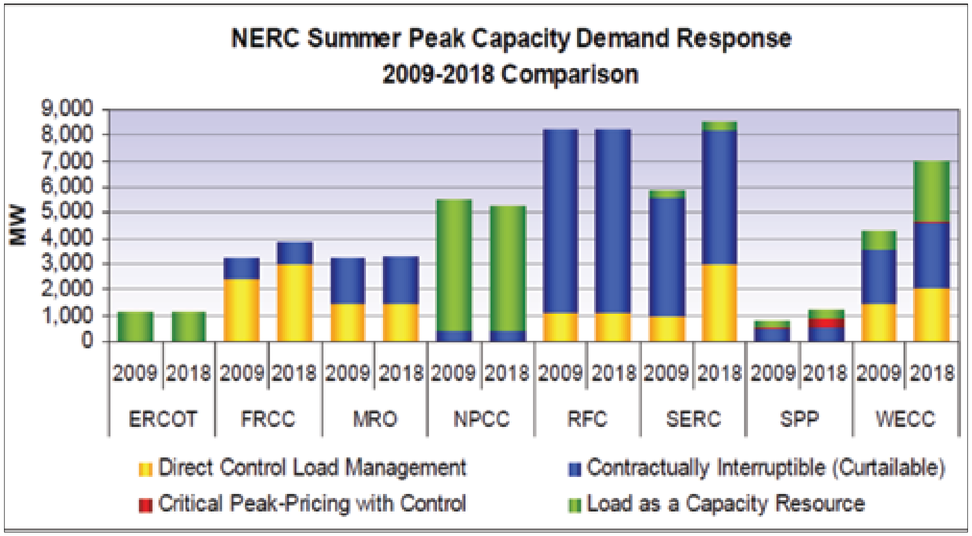


Figure 26: NERC Summer Peak Capacity Demand Response, 2009-2018

Source: NERC 2009 Long-Term Reliability Assessment Report[44]

Solar Integration Study. That report states: "It may be more cost-effective to use DR to address the 89 hours of contingency reserve shortfalls rather than increase spinning reserves for 8,760 hours of the year. DR can save up to $600M/year in operating costs versus committing additional spinning reserves."[45]

On March 18, 2010, FERC issued a Notice of Proposed Rulemaking (NOPR) proposing to improve competiveness in organized wholesale energy markets by compensating DR resources based upon the Locational Marginal Price (LMP) in the appropriate RTO or ISO. FERC has indicated that DR resources are an important component of its goal of promoting system reliability and competitiveness in wholesale markets. FERC is particularly focused on the ability of DR to directly bid into the market and lower demand, thus lowering clearing prices. DR also can relieve the pressure on more expensive generation or eliminate the need to build new capacity. FERC offers that DR can apply downward pressure to generators and affect their market power, as they risk bidding too high and being excluded from dispatch.

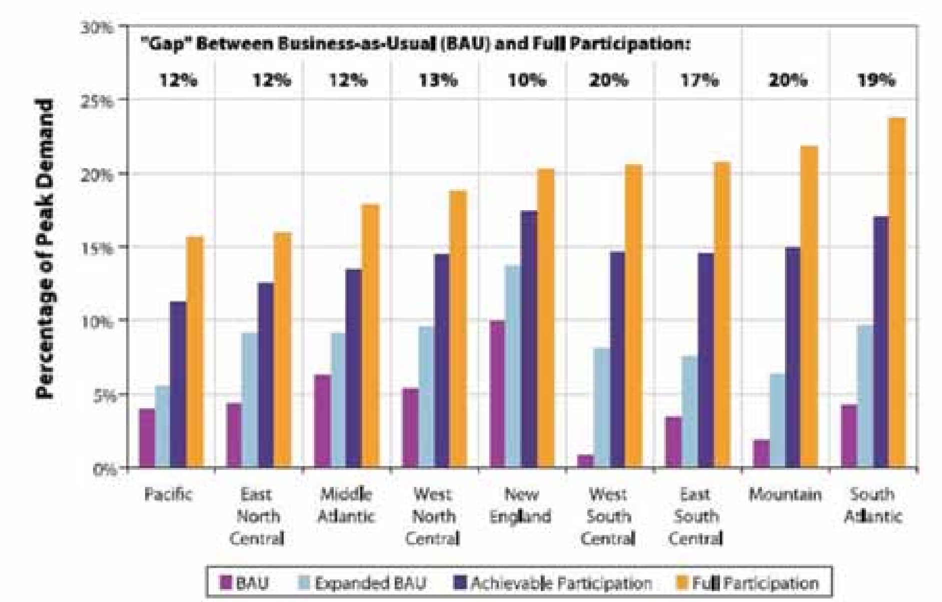


Figure 27: Regional Demand Response Potential

Source: FERC 2010 National Action Plan on Demand Response[46]

Peter Behr, writing for the *New York Times*, reported on Nov. 12, 2010, that FERC's DR NOPR is a "mandate that consumers who reduce electricity consumption in the wholesale power markets FERC regulates—or energy aggregators that arrange to do that for them—would be paid the full market price for the power, as if they were generators. Companies bent on strategically managing their electricity usage, like Wal-Mart and the growing corps of power aggregators, enthusiastically support this initiative. Leading generators and power marketers oppose it just as stiffly, stating that consumers would be getting a double dip, saving money by forgoing purchases of power, and then being paid again with the market price for the power they never used."

Distributed Generation

The REDI report identified DG as a potential game changer, and GEO is sponsoring a DG study to quantify its potential opportunities in the REA and muni context. GEO is also helping to support the Fort ZED project in Fort Collins to determine, in part, the extent to which DG capacity can be dispatched to address utility peak demand. Preliminary results should be available in 2012.

DG is known by several names: distributed energy resources, on-site generation, dispersed generation, embedded generation, decentralized generation, and decentralized energy.

DG electricity is provided from a variety of small energy sources. Accelerated growth in DG (often represented by PV, which generates electricity on the customer side of the meter) could reduce peak demand and overall consumption; it also could slow the need for distribution infrastructure upgrades. The New Rules Project's report, *Energy Self-Reliant States*[47], suggests that DG could mitigate the need for utility-scale renewable energy and high-voltage transmission development. However, given load growth and the grid's service as a battery for many DG technologies, it remains to be seen whether DG can supply enough power to significantly affect the need for more supply-side resources. Consideration also must be given to the economics of expanding the grid versus supporting DG.

- **Smart Grid and Distributed Generation:** According to the University of Colorado's smart grid white paper, *Smart Grid Deployment in Colorado: Challenges and Opportunities*, "DG is an approach that employs small-scale technologies to produce electricity close to the end users of power. Today's DG technologies often consist of

Replacing 30 percent of the vehicles currently in the Xcel Energy service territory with PHEV-20s that derive 39 percent of their miles from electricity would increase total load by less than 3 percent.

renewable generators (i.e., PV, wind turbines, and microturbines) and offer a number of potential benefits…. DG also has the potential to mitigate overloaded transmission lines, control price fluctuations, strengthen energy security, and provides greater stability to the electricity grid."[48] The report provides details on how smart grid technologies enhance DG applications by using two-way communications that can employ DG resources for capacity in the following ways:

- Combined heat and power (cogeneration) plants increase the efficiency of on-site electricity generation by using the "waste heat" for existing thermal loads.
- Premium power production reduces frequency variations, voltage transients, surges, dips, or other disruptions.
- Backup power is used in the event of an outage, as a backup to the electric grid.
- Peak shaving refers to use of DG during times when electric use and demand charges are high.
- Low-cost energy refers to use of distributed energy sources as primary power that can be produced locally at lower cost than if it were purchased from electric utilities.
- **Plug-in Hybrid Electric Vehicles (PHEVs) as a DG Source:** Among the many benefits of PHEVs (Figure 28) are their ability to lower carbon emissions and provide new energy resources to the electric grid with the use of smart grid technologies. Storing energy in batteries, either with electric vehicles (EV) or PHEV, offers the potential for quick-start capabilities and, in the case of EV, opportunities for regulation. Additional EV services, including regulation, are being researched. NREL's January 2010 technical report, *The Role of Energy Storage with Renewable Electricity Generation*,[49] states that, "Electric vehicles (EVs—used here to represent both 'pure' electric vehicles or plug-in hybrid electric vehicles) are a potential source of flexibility for VG [variable generation] applications.

Figure 28: Plug-in Electric Vehicle (PHEV)

The charging of EVs can potentially be controlled, and provide a source of dispatchable demand and DR. Controlled charging can be timed to periods of greatest VG output, while charging rates can be controlled to provide contingency reserves or frequency regulation reserves. Vehicle to grid EVs can partially discharge stored energy to the grid may provide additional value by acting as a distributed source of storage."

- In 2007, NREL produced *Costs and Emissions Associated with Plug-In Hybrid Electric Vehicle Charging in the Xcel Energy Colorado Service Territory*[50]. *(Figure 29)*

The report's conclusions follow:

- The actual electricity demands associated with PHEV charging are quite modest compared to normal electricity demands. Replacing 30 percent of the vehicles currently in the Xcel Energy service territory with PHEV-20s that derive 39 percent of their miles from electricity would increase total load by less than 3 percent.
- A very large penetration of PHEVs would place increased pressure on peaking units if charging is completely uncontrolled. There is a large natural coincidence between the normal system peaks and when significant charging would occur during both the summer and winter seasons.

No additional capacity would be required for even a massive penetration of PHEV if even modest attempts were made to optimize system charging.

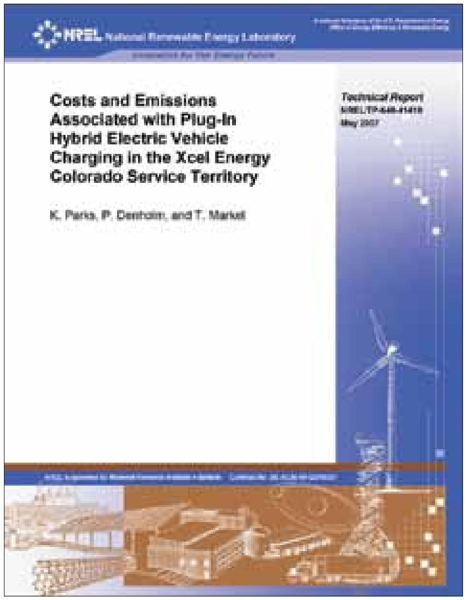


Figure 29: Costs and Emissions Associated with Plug-In Hybrid Electric Vehicle Charging in the Xcel Energy Colorado Service Territory, May 2007
Source: National Renewable Energy Laboratory

- No additional capacity would be required for even a massive penetration of PHEV if even modest attempts were made to optimize system charging. Simple time-of-day charging could easily place all end-of-day charging requirements into off-peak periods. Utility-controlled charging would create additional net benefits by using existing plants.
- In the near term, the Xcel Energy system uses gas for marginal generation most of the time. Coal is used for less than 20 percent of all PHEV charging, even in scenarios that use exclusively "off-peak" electricity.
- Because most near-term PHEV charging will likely be derived from gas units in the evaluated scenarios, the cost of natural gas drives the cost of PHEV charging.
- The incremental cost of charging a PHEV fleet in the overnight charging cases ranges from $90 to $140 per vehicle per year. This translates to an equivalent production cost of gasoline of about 60 cents to 90 cents per gallon.
- Total NOx emissions from PHEVs in the evaluated scenarios are equal to or slightly less than those from non-plug-in HEVs. Although total NOx reductions may be relatively small, tailpipe NOx is significantly reduced as more miles are electrically driven. Without the use of an air quality model, it is difficult to quantify the net benefit of reducing tailpipe NOx while increasing generator NOx emissions. In addition, significant opportunities exist for further NOx reductions in the electricity sector as many units are not fitted with the latest emission control technology.
- Because gasoline contains little sulfur (it is removed at the refinery), the most important factors for net SO2 emissions are those from refinery operations and from marginal coal generation. For the evaluated daytime and delayed charging scenarios, total PHEV-related SO2 emissions are expected to be less than from conventional and hybrid vehicles. In the off-peak charging case—or in any case where coal is at the margin a large fraction of the time—SO2 emissions are expected to be greater. Any emissions comparison must be placed in context of the national cap on SO2 emissions, which does not allow a net increase in SO2. Thus, any increase in SO2 emissions resulting from additional load created by PHEV charging must be offset by a decrease in emissions elsewhere.
- In all cases, there are significant reductions in net CO_2 emissions from PHEVs.
- Further analysis is needed to design and analyze several potentially improved charging scenarios. A more optimal charging scenario would likely combine off-peak charging to minimize costs, while including some midday (continuous) charging to increase gasoline savings. This would potentially provide both Xcel Energy and its customers with the greatest overall mix of PHEV benefits.

As part of Xcel Energy's Smart Grid City project in Boulder, Toyota Motor Sales U.S.A. Inc. has provided 18 volunteer residents with Prius PHEVs. The vehicles are the focus of an interdisciplinary research project coordinated by the University of Colorado's Renewable and Sustainable Energy Institute (RASEI), a new joint venture between NREL and the University of Colorado at Boulder. Study participants will work with researchers to gather data on vehicle performance, charging patterns, customer behavior and preferences, and electric utility and customer interactions.[51]

As electric vehicles enter the market in 2011, utilities across the country are analyzing the challenges and opportunities. Xcel Energy continues to work closely with NREL and other research institutions to determine how to best address to the topic. See Figure 30. Batteries or other energy storage technologies have the potential to help utilities with frequency regulation, peak

As electric vehicles enter the market in 2011, utilities across the country are analyzing the challenges and opportunities.

Figure 30: Electric Vehicle
Photo credit: National Renewable Energy Laboratory

shaving, and where lines or transformers are overloaded. They are also important to supporting the use of renewable resources for power generation, especially wind and solar, by enabling the energy to be stored for use at the most beneficial times. A detailed report on advanced batteries was produced in September 2010 by the National Institute of Standards and Technology, and the National Electrical Manufacturers Association.[51a]

Colorado's Smart Grid Activities

Colorado and the Smart Grid

Smart grid policies and activities vary widely from state to state. Some states have established smart grid goals, while others have specific smart grid policy initiatives and legislation. Many states have not yet started such programs.

Colorado passed Senate Bill 10-180 that created the Colorado Smart Grid Task Force (SGTF). GEO convened the SGTF, one of the only task forces of its kind in the country. Its purpose was to examine and recommend to the PUC and the General Assembly appropriate management options on issues related to development and implementation of a smart energy grid in Colorado.[52]

As part of the investigation into smart grid, GEO commissioned a report by the Center for Environmental and Energy Studies (CEES) at the University of Colorado at Boulder. CEES's 128-page report, *Smart Grid Deployment in Colorado: Challenges and Opportunities*,[53] provided the SGTF with a discussion of important smart grid topics and probable and potential issues related to smart grid deployment. A report with recommendations has been presented to the Colorado General Assembly.

Certain Colorado utilities have demonstrated their leadership in and support of the smart grid. Five Colorado electric utilities have installed smart meters.[54] Black Hills Energy installed more than 42,000 smart meters in its Pueblo service area.[55] Colorado Springs Utilities has converted all its meters to smart meters, creating 535,000 endpoints for 310,000 gas, electric, and water customers.[56] Fort Collins Utilities is installing 79,000 smart meters and in-home demand response systems, as well as smart thermostats and air-conditioning and water heater control switches. It also is installing automated transmission and distribution systems and enhancing grid security.[57] Advances in smart meter replacement and end-to-end solutions are progressing with other utilities in Colorado. Of particular note is PSCo's SmartGridCity initiative in Boulder, a comprehensive system that includes a digital, high-speed broadband communication system; upgraded substations, feeders, and transformers; and a build-out of more than 20,000 smart meters to serve as a living laboratory that allows the utility to explore smart grid tools in a real-world setting.[58]

Conclusion

Colorado utilities and policymakers have stepped forward with legislation, regulatory policies, and efficiency programs that capitalize on a multitude of demand-side measure opportunities. The state also is keeping a close watch on the long-term requirements of a stable, reliable power supply for its citizens. Demand-side measures—which include energy efficiency, demand response, and distributed generation—will benefit from the advent of smart grid technologies that aim to reduce load growth and costly peak demand requirements.

Colorado utilities will benefit from the policies, regulations, and infrastructure advanced by the legislature and the PUC to pursue aggressive, cost-effective DSM measures. Increasing Colorado's commitment to demand-side measures in the electricity sector will not only strengthen the system, but also will avoid more costly capacity additions.

Pursuit of DG and utility-scale renewable generation are not mutually exclusive activities. Both need to be pursued in parallel. It remains to be seen whether demand-side measures will alleviate the remaining need for high-voltage transmission to connect the utility-scale renewable resources necessary to meet a variety of electric, environmental, and economic imperatives.

After identifying Colorado's utilities' existing financial incentives to generate and sell electric power, the legislature, utilities, and regulators should craft structural modifications to align utilities' incentives with the success of their demand side initiatives.

3. Addressing Climate Change and Water Issues Through Renewable Energy

Overview

Although opinions certainly vary about its causes, the long-term warming trend over the last century has been well-documented. Increased warnings from the scientific community point to a growing body of data that indicate rising dangers from the build-up of human-related greenhouse gases—produced mainly by burning of fossil fuels and forests. Scientists worldwide have immersed themselves in studying the climate, and most project a variety of results, including more frequent and intense extreme weather events; disruption of water supplies; and negative effects on agriculture, ecosystems, and coastal communities.

The dilemma lies in the fact that the traditional economic growth model has been driven in large part by the burning of fossil fuels. Figure 31 illustrates U.S. CO_2 emissions by source. A massive body of evidence exists that CO_2 produced by burning fossil fuels produces a greenhouse effect that contributes to temperature increase and thus endangers sustainability and habitability for future generations and the natural ecosystem that supports life on the planet.

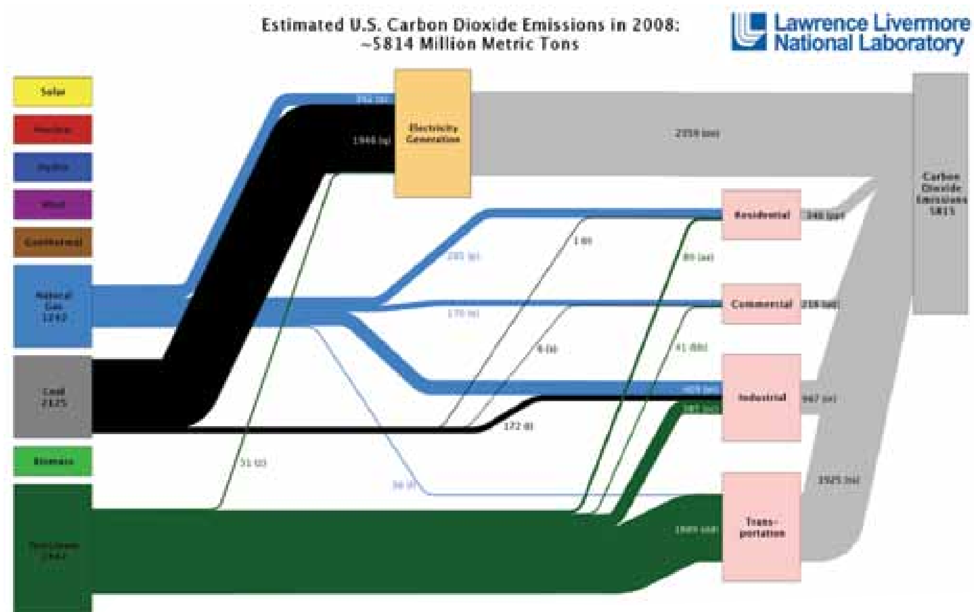


Figure 31: Estimated Carbon Dioxide Emissions in 2008

Source: Lawrence Livermore National Laboratory[59]

The scientific method certainly calls for challenging whether CO_2 and other greenhouse gases are major contributors to temperature rise, and whether the temperature rise[59A] is disrupting the global climate. At some point, however—and that point may have been reached at least a decade ago—exercising the precautionary principle is now warranted, especially given the mounting environmental and economic consequences of inaction. The responsibility to step forward and address the problem rests with this generation.

Joining a wide number of government agencies in the United States and around the world, the U.S. Defense Department has conducted in-depth studies of climate change and has formally recognized the challenge as a national defense issue of the first order. A series of papers released in November 2010 by the German Marshall Fund of the United States[60] details the links between climate change and national security, and sets forth options for transatlantic policy responses. The papers address the intersection of climate and security from several angles. The Fund states that, "The transatlantic partners must consider how to respond to the risks of climate change in order to avoid increasing conflicts and tensions around the world. The appropriate response will not be limited to one country or to the military domain; rather, it must be both multilateral and multi-faceted, encompassing the full range of available policies including development cooperation, conflict prevention, and humanitarian assistance, as well as climate change adaptation and mitigation. The development of adaptation strategies, the efforts to establish a mechanism to reduce emissions from deforestation and forest degradation, and the preparation of low carbon development plans offer promising potential. By designing these instruments in a conflict sensitive way, climate change concerns can be mainstreamed into development, foreign and security policies."

"Can Coloradans really make a difference? I believe we can, and that we have a moral obligation to try."

"Global climate change presents one of the biggest energy and environmental policy challenges this country has ever faced."

The Edison Electric Institute (EEI), the national trade association representing IOUs, states that: "Global climate change presents one of the biggest energy and environmental policy challenges this country has ever faced. EEI member companies are committed to addressing the challenge of climate change and support an 80-percent reduction in greenhouse gas emissions by 2050. As Congress works to address this issue, it is essential to include effective consumer-protection measures that help to reduce price increases for consumers and avoid harm to U.S. industry and the economy."

Colorado's Climate Action Plan

In November 2007, Governor Ritter produced the Colorado Climate Action Plan. In the introduction to the CAP,[61] the governor said:

"Global warming is our generation's greatest environmental challenge. The scientific evidence that human activities are the principal cause of a warming planet is clear, and we will see the effects here in Colorado. But the seeds of change are also here in Colorado, in our scientific and business communities, and in each of us individually. This Colorado Climate Action Plan is a call to action. It sets out measures that we in our state can adopt to reduce emissions of greenhouse gases by 20 percent by 2020, and makes a shared commitment with other states and nations to even deeper emissions cuts by 2050. Why is this important? For Colorado, global warming will mean warmer summers and less winter snowpack. The ski season will be weeks shorter. Forest fires will be more common and more intense. Water quality could decline, and the demand for both agricultural and municipal water will increase even as water supplies dwindle.

Can Coloradans really make a difference? I believe we can, and that we have a moral obligation to try. In setting and achieving our climate action goals we will show leadership as a state, engage with neighboring states in a regional effort, and call upon the federal government to take strong actions on national initiatives.

The plan includes a strong plea, voiced also by the bipartisan Western Governors' Association, for an accelerated round of federal investments to deploy clean coal technologies. Its success depends on everyone doing his or her part. We can reduce global warming and keep our economy strong and vibrant. This is an exciting time for Colorado as we look toward an expanded New Energy Economy with new jobs, new businesses and new investments. If we do this right, we can turn the challenge into opportunity for Colorado's workforce. Insulating homes and buildings, establishing wind farms, building solar arrays, and constructing clean coal power plants will demand thousands of trained workers. Stepping up energy conservation and developing new sources of clean, renewable energy will grow the New Energy Economy in Colorado.

If we don't do it right, in Colorado, across America and around the globe, our children and grandchildren will inherit a much diminished world." The CAP report indicates "observation in recent decades show that Colorado is seeing: Shorter and warmer winters, with a thinner snowpack and earlier spring runoff; less precipitation overall, and more falling as rain than snow; longer periods of drought; more wildfires, burning twice as many acres each year than before 1980; widespread beetle infestations wiping out forests, and die-off in aspen stands; and rapid spread of West Nile virus due to higher summer temperatures."

Scientific Studies Provide the Foundation for Policy Changes

Several studies quantify the effects of climate change and provide guidance on how Colorado plans for the future. A key document is the U.S. Climate Change Science Program's *Climate Change Impacts in the United States.*[62] Implications derived from reports such as this are being considered by a host of Colorado energy and environment analysts in research institutions, in government, by regulators, and utilities. One implication relevant to the energy sector is that rising winter temperatures may reduce the need for residential and commercial heating, decreasing overall winter demand for natural gas. If this were to happen, natural gas consumption may decrease as the need for winter heating declines. However, overall electricity consumption may be expected to increase if more residences install air conditioning. Another implication may be that increasing water scarcity due to climate change may increase the demand for energy needed to pump water throughout the state.

Climate change may have various physical effects on energy supply and energy infrastructure. A partial list includes the following.

- Increased ambient temperatures may reduce both efficiency and overall power output at natural gas-fired power plants.
- Hydroelectric generation efficiency may be affected by changes in precipitation, stream runoff, and many other climate-related factors.
- Changes in cloud cover may affect the efficiency of solar energy resources.
- Reductions in water availability and changes in the frequency of extreme events may affect production and distribution of fossil fuel resources, which could potentially affect electricity generation and price.

Addressing Climate Change in Several Venues

An expanding group of individuals, businesses, institutions, governmental agencies, and associations are working to address the climate change challenge. To illustrate the span of activities, a partial list includes the Western Climate Initiative, the Regional Greenhouse Gas Initiative, the Western Governors' Association, Powering the Plains, Carbon Sequestration Regional Partnerships, the U.S. Mayors' Climate Protection Agreement, the Cities for Climate Protection Campaign, and the National Governors' Association. On Feb. 2, 2010, the U.S. Securities and Exchange Commission issued a release to give public companies, including IOUs, interpretive guidance regarding the SEC's existing disclosure requirements relating to climate-change matters.

Carbon Capture and Sequestration

EEI defines, and describes carbon capture and sequestration techniques as follows: "Carbon Capture and Sequestration (CCS) is one of the key technologies needed to reduce emissions of CO_2, a major greenhouse gas. CCS technologies will capture CO_2 from fossil fuel-based power plants, transport it, and store it underground instead of releasing it into the atmosphere." See Figure 32. CCS is a relatively new technological approach, however, and many technical and non-technical issues are involved in capturing and storing CO_2.

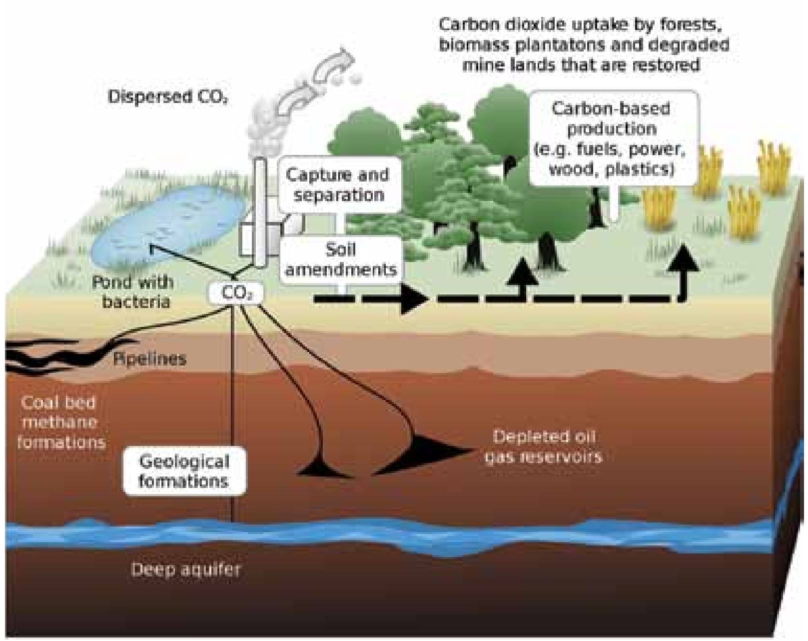


Figure 32: Carbon Capture Sequestration Cycle

During the generation of fossil fuel-based electricity—from coal, natural gas, and fuel oil—CO_2 is released into the atmosphere. CCS is a process by which CO_2 is separated from emission sources, transported, and injected into suitable underground geologic locations, such as deep saline formations, unmineable coal seams, basalt formations, or depleted oil and gas fields. It is estimated that the United States has an abundance of underground storage capacity, but these potential storage areas are not evenly distributed around the country.

The CO_2 is captured, or 'separated,' from flue gas by means of a chemical or physical process. The captured CO_2 is then compressed (i.e., pressurized) in order to change the gas into a liquid. The liquid CO_2, also referred to as a supercritical fluid, is denser than in its original gaseous state and is easier to transport by pipeline. CO_2 in small volumes also can be transported as a liquid in tanks by ship, road, and rail. The CO_2 can then be injected into depleted oil and gas reservoirs or into deep underground saline formations for storage; or, it can be injected into depleting oil reservoirs to extract more oil and then to store the unused CO_2."

CCS Activity Initiated by Governor Ritter

On March 10, 2010, Governor Ritter established the Carbon Capture and Sequestration Task Force (CCSTF). Colorado State Geologist Vince Matthews said, "Interest in carbon capture and sequestration has grown dramatically

Future technological advances can help Colorado's coal industry succeed in a carbon-constrained economy, but complex legal, regulatory and policy issues must be resolved for carbon capture and sequestration to be successful in Colorado.

in recent years," Colorado should encourage its progress by ensuring that a workable legal and policy regime is in place before the state is asked to evaluate specific projects." Future technological advances can help Colorado's coal industry succeed in a carbon-constrained economy, but complex legal, regulatory and policy issues must be resolved for carbon capture and sequestration to be successful in Colorado. To help pave the way, the governor asked the Department of Natural Resources (DNR) to convene a task force to resolve the many policy questions that carbon capture and underground storage pose for the industry, property owners, and regulators. The broad-based, 12-member CCSTF will examine these issues with a goal of developing omnibus CCS legislation for the 2011 General Assembly.

"The Ritter administration is committed to ensuring that Colorado's abundant coal resources remain a significant contributor to our energy portfolio," said Jim Martin, who was, at that time, DNR's executive director. "While carbon capture and storage technology is still in development, it's to everyone's benefit that we act now is to establish a stable regulatory environment by addressing the questions we know are in front of us." Several states—including Wyoming, North Dakota, and Montana —already have considered or passed aspects of the regulatory structure necessary for CCS. The CCSTF is reviewing other states as Task Force develops a policy framework for Colorado.

Questions the task force are addressing include.

- Who should own the pore space in which CO_2 would be injected and stored: surface owners, mineral owners, the State of Colorado, or the federal government?
- Who should own the CO_2 after it's been injected in the geologic formation?
- What environmental and health regulations are appropriate for geologic CO_2 sequestration?
- Which state agency should set standards for the injection of CO_2 in geologic formations?
- Which state agency should regulate and permit the injection?
- Who should be responsible for long-term management of geologic sequestration sites?
- How should CO_2 infrastructure be handled?

The task force includes Senator Gail Schwartz (D-Snowmass) and Senator Al White (R-Steamboat Springs), Representative Clare Levy (D-Boulder) and Representative Marsha Looper (R-Calhan), two members each from the utility, coal, and oil and gas industries, and one member each from cement and conservation interests.

New EPA CCS Rules Finalized

In a press release issued on Nov. 22, 2010, the EPA announced that it finalized two rules related to CO_2 capture and sequestration. The press release states that the new rules[63] "aim to protect drinking water and to track the amount of CO_2 sequestered from facilities that carry out geologic sequestration. Together, these actions are consistent with the recommendations made by President Obama's interagency task force on this topic and help create a consistent national framework to ensure safe and effective deployment of technologies that will help position the United States as a leader in the global clean energy race."

EPA Administrator Lisa P. Jackson said: "Today the Obama Administration reaffirmed its commitment to leading the way in the clean energy future. We're taking a major step towards path breaking innovations that will reduce greenhouse gases and put America in the forefront of the clean energy economy. By providing clarity about greenhouse gas reporting and the necessary protections for drinking water sources during carbon sequestration, we've cleared the way for people to use this promising technology."

The Energy/Water Nexus

Increasing water requirements form a nexus with strategic electric power questions facing Colorado, since traditional electric-generating technologies use large volumes of water. The Colorado Water Conservation Board has concluded that Colorado's already stressed current water use will likely almost triple by 2050 due to population and economic growth and environmental needs.

It is estimated that 4,000 MW of wind energy installed in the Interior West will result in a savings of 6.31 billion gallons.

The DOE's *20% Wind Energy by 2030* report states: "Water scarcity is a significant problem in many parts of the United States. Even so, few U.S. citizens realize that electricity generation accounts for nearly 50% of all water withdrawals in the nation, with irrigation withdrawals, coming in second at 34% (USGS 2005). Water is used for the cooling of natural gas, coal, and nuclear power plants and is an increasing part of the challenge in developing those resources. Although a significant portion of the water withdrawn for electricity production is recycled back through the system, approximately 2% to 3% of the water withdrawn is consumed through evaporative losses. Even this small fraction adds up to approximately 1.6 to 1.7 trillion gallons of water consumed for power generation each year. Recent research of the water/energy nexus produced findings that nuclear plants use the most water of electric power options, at approximately 43 gallons of water for every kilowatt-hour (kWh) generated. Coal and waste incineration plants use approximately 36 gallons of water for every kWh generated. Natural gas plants use approximately 14 gallons of water for every kWh generated. As additional wind generation displaces fossil fuel generation, each megawatt-hour generated by wind could save as much as 600 gallons of water that would otherwise be lost to fossil plant cooling."

The DOE's WindPower America program sponsors in-depth research regarding the energy/water nexus.[64] The STAR analysis concludes that Colorado's future electricity sector should rely heavily on wind power, which does not consume water to generate electicity. The DOE's energy/water nexus material states that, "Greater additions of wind to offset fossil, hydropower, and nuclear assets in a generation portfolio will result in a technology that uses no water, offsetting water-dependent technologies. By diversifying the generating portfolio energy mix, a utility can manage its water supply risks. It is estimated that 4,000 MW of wind energy installed in the Interior West will result in a savings of 6.31 billion gallons." The magnitude of the energy/water nexus issue is reflected in Figure 33.

A draft report by the Colorado Water Conservation Board states: "Power providers can reduce vulnerability without changing their generation technology by purchasing additional senior water rights and drought-contingent leases. They can also diversify their water sources. Nevertheless, the best solution is to decrease the water required for power generation. In the case of traditional fuel sources this can be achieved by implementing dry cooling and combined cycle technology. Renewable resources like wind and solar require almost no water for generation. At the state level, government has already moved to support less water dependent power generation with the 30% renewable by 2020 goal. Further government support of water-independent technology will lower drought vulnerability. Also, improving transmission line capacity increases the ability of the State to react and fill deficits if power generation is curtailed as a result of drought. Increasing transmission line capacity to other states will provide additional flexibility to import power if necessary." Figure 34 illustrates the interrelationship between water and energy.

The Colorado River's Future

In early 2010, the U.S. Department of the Interior (DOI) announced that Secretary of Interior Ken Salazar committed $1.5 million to establish a study group

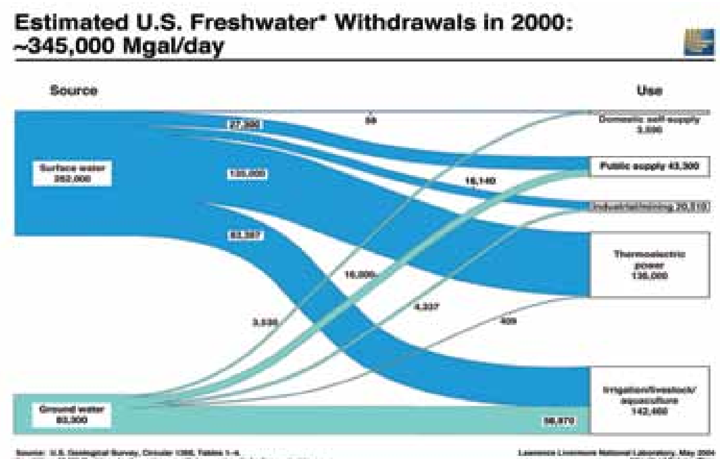


Figure 33: LBNL Water Chart

Source: Lawrence Livermore Laboratory, May 2004[65]

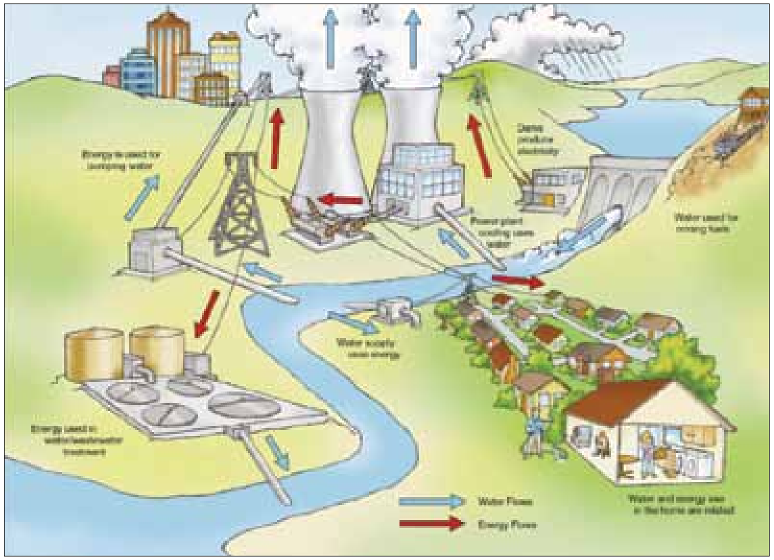


Figure 34: Example of the Interrelationship Between Water and Energy
Source: Colorado Water Conservation Board

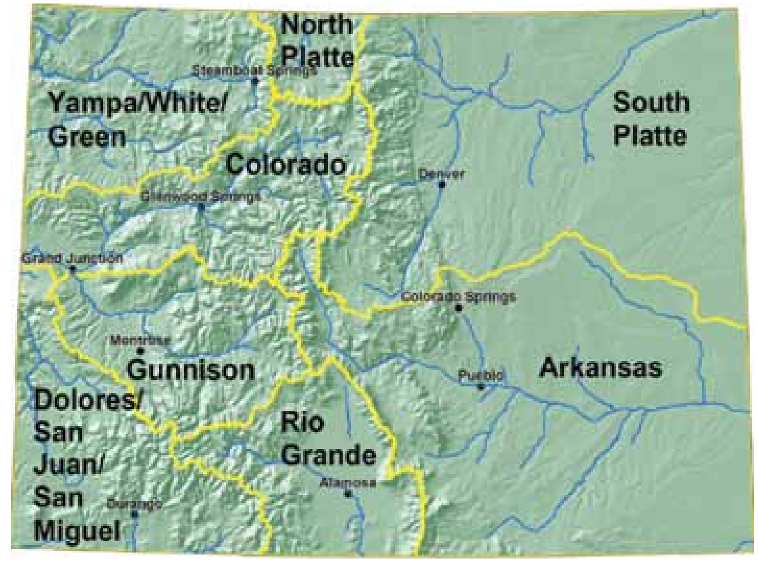


Figure 35: Colorado's River Basins

focusing on the Colorado River basin. The study is described by the DOI as "the first of three river basin studies – called the WaterSMART program – aimed at measuring the nation's water demands and resources, including the potential impacts of climate change.

Since 1922, the Colorado River's water has been allocated among seven Western states under a legal compact. The amount each state can draw from the river is based on water levels measured in 1922, after several wet years. There is a big gap between the amount of water flowing then – about 16.4 million acre-feet per year – and the actual flow in normal years, which averages about 13.5 million acre-feet. The situation has been made even worse by 11 straight years of drought. The average annual flow in the heart of the drought (2000 to 2004) was 9.6 million acre-feet. Historical tree-ring samples, whose growth patterns indicate rainfall, suggest that the recent drought is not an anomaly and that drought has been the normal condition in much of the river basin for centuries. And droughts are likely to continue as the climate warms.

So far the states have been making do, thanks to water stored in reservoirs along the river. But they are managing a depleted resource with a forbidding future. Lake Mead, near Las Vegas and the largest reservoir on the river, is at its lowest level since it was first filled 75 years ago. The river's flow is approaching the low-level mark that would allow states in the upper basin to withhold water from states in the lower basin – a change that would hit Nevada hardest. The seven states have already begun intensive water conservation efforts. It seems clear that these efforts will have to be redoubled, not only to meet human needs but also to protect the diverse ecosystems the river nourishes on its way from its headwaters in the Colorado Rockies to the Gulf of California. The study will help chart that course, and, from the looks of things, its findings cannot come a moment too soon." Figure 35 shows Colorado's river basins.

Renewable Energy in Colorado

SB07-091 Task Force on Renewable Resource Generation Development Areas Report

In 2007, the Colorado General Assembly passed SB07-091, which created "The Task Force on Renewable Resource Generation Development Areas."

The task force produced its report, *Connecting Colorado's Renewable Resources to the Markets,*[66] in December 2007 and updated it in July 2008. The task force was charged with mapping renewable resources throughout the state. The report contains maps of these resources and identifies generation development areas (GDAs) capable of hosting a minimum of 1,000 MW where the resource can be developed. The maps in the report identify existing generation and areas where high voltage transmission is needed to bring renewable resources to markets. The report concluded that Colorado's rich renewable resources, particularly utility-scale wind and solar, could be economically tapped if high-voltage transmission was expanded to the GDAs.

The report concluded that Colorado's rich renewable resources, particularly utility-scale wind and solar, could be tapped if enough high-voltage transmission was expanded to the GDAs.

Since 2006, Colorado has experienced a steady growth in utility-scale wind generation development. Large-scale solar power plants have recently come on line, and more developments are expected should Colorado make a commitment to the timely development of necessary high-voltage transmission infrastructure.

Utility-Scale Wind Projects in Colorado

As of the release of this report, 1,299 MW of wind is installed in Colorado, and at least 500 MW is under construction. The following Colorado wind projects have a nameplate capacity of 25 MW and above:

- **The Colorado Green Wind Farm** is a 162 MW project located 20 miles south of Lamar. Completed in 2003, the project uses 108 GE 1.5 MW wind turbines and is owned under a 50/50 joint venture by Iberdrola Renewables USA and Shell WindEnergy Inc.
- **The Cedar Creek Wind Farm (I)**, a 300.5 MW installation, is located eight miles east of Grover in north-central Weld County. It became fully operational in January 2008. Using 221 Mitsubishi 1-MW wind turbines and 53 1.5-MW GE wind turbines, the project provides enough wind-powered electricity for 90,000 homes. Power produced from the wind farm is sold to PSCo.
- **The Peetz Table Wind Energy Center,** also called the Peetz Wind Farm, is a 400 MW power station in northeastern Colorado owned by NextEra Energy Resources. The project can generate enough electricity to power nearly 120,000 homes using 267T-GE wind turbines. The wind farm has 20 full-time employees.
- **Ponnequin Wind** is located in Weld County, just south of the Wyoming border and east of Interstate 25. The project consists of 44 wind turbines with a power production capability of up to 30 MW. Colorado's first commercial wind farm, it was built in several phases starting in 1998. PSCo owns the Ponnequin Wind Farm and owns and operates 37 of the 44 turbines; Ponnequin Acquisitions owns and operates the remaining seven turbines. When the first turbines were installed in 1998, they represented the largest utility investment at the time from a green-pricing program; power produced at Ponnequin was sold through PSCo's Windsource program.
- **The Ridgecrest-Peetz Project** is a 29.7 MW development by enXco, owned by Caithness.
- **The Spring Canyon Project,** a 60 MW development, went online in 2006 in Peetz. The project, owned by Invenergy, uses GE turbines.
- **The Twin Buttes Project,** a 75 MW development, went online in 2007 in Bent County, Colorado. Owned by PPM Energy, the project deploys 50 GE turbines.
- **Tri-State Generation and Transmission Association Inc.** completed its first major wind acquisition in November 2010 with its 51 MW Kit Carson wind project near Burlington, developed by Duke Energy Generation Services. The facility's 34 1.5 MW GE turbines are situated on a 6,000-acre site northwest of Burlington, within the service territory of Tri-State member co-op K.C. Electric Association. No new transmission facilities were necessary for the Tri-State system, since the wind project was directly connected to an existing Tri-State 230-kV line between substations.
- **RES Americas** will complete a 252 MW wind project in Lincoln and Elbert counties by mid-2011. The Cedar Point Wind Energy Project is a Colorado New Energy Economy success story. RES is headquartered in Broomfield, and the project's 139 1.8-MW Vestas turbines will be manufactured in Colorado. The project recently was sold to Enbridge, a Canadian pipeline company, with construction work to be completed by RES Americas. Enbridge and RES Americas expect the project to yield approximately 875,000 MWh (corresponding to the annual consumption of approximately 80,000 Colorado households).
- **BP – The Cedar Creek II** wind farm will have a capacity of 250 MW and will be built on a 30,000-acre parcel about 20 miles north of New Raymer, east of the existing 300.5 MW Cedar Creek I wind farm. PSCo will purchase all the power for a term of 25 years.

AWEA reports that about 85,000 Americans currently work in wind and related industries.

In addition to the above projects, the following are potential new wind projects identified at the time of publication.

- **The Cheyenne Ridge Wind Project** is to be located approximately 15 miles north of Cheyenne Wells. The project, with a capacity of 800 MW, will be built in phases. The project's two interconnection options include a 115-kilovolt (kV) transmission line that runs north/south through the project and future transmission lines with larger capacity that currently are proposed for the region. The project will encompass 125,000 acres and consist of more than 75 landowners. Although the commercial operation date for the first phase could be as early as 2012, later phases will depend upon future transmission lines. The power produced by the project will be marketed to local and regional utilities. The developer is TradeWind Energy LLC, headquartered in Lenexa, Kansas. If all phases are completed, the project will produce enough power for approximately 240,000 Colorado homes.
- **Expansion of Colorado Green.** According to a Colorado Springs construction industry press release dated May 27, 2010, an expansion of the wind farm is expected. "Iberdrola Renewables is expecting to expand on the giant wind farm in Prowers County. There will be an addition of 50 to 75 wind towers added on the 11,000 acre Colorado Green Wind Power Project, between Lamar and Springfield. 'The company is working to complete remaining development items,' notes Jan Johnson, a spokesperson for Iberdrola. The proposed expansion could be up to 75 MW, based on existing interconnection capacity reserved at the Lamar substation. Construction is not scheduled to begin yet, however."

Wind Energy Update

Xcel Energy reported in 2009 that the company plans to have approximately 7,400 MW of wind in place, companywide (multistate), by 2020.[67]

According to a November 2010 statement by the American Wind Energy Association: "After a growth spurt that was uninterrupted since 2005, wind power capacity installations will fall to 2007 levels this year, even if the fourth quarter lives up to current expectations. Factors in the slowdown include lack of long-term U.S. energy policies, such as a Renewable Electricity Standard, and resulting lack of certainty for business, which has the country's utilities failing to move forward with wind build-out plans. Also contributing were continued sluggishness in the economy; resulting lower electrical demand; and, lower prices to support new generating capacity. Over 6,300 MW is now under construction, so the U.S. is likely to end 2010 with over 5,000 MW completed." [68]

Worldwide, the Global Wind Energy Council reports, 40 GW of new wind is expected to be put in the ground in 2011, and the world will pass the 200 GW cumulative mark by early 2011. The council predicts that global wind capacities will more than double during the next four years, exceeding 400 GW by 2014.

The wind industry provides much-needed employment. The U.S. Bureau of Labor Statistics (USBLS) reports that U.S. wind-generating capacity grew by 39 percent from 2004 to 2009. Future expansion means the number of jobs will likely grow with it with many opportunities for workers in search of new careers. The USBLS says that "these careers extend beyond the wind farm…it also takes the efforts of workers in factories and offices to build and operate a turbine." AWEA reports that about 85,000 Americans currently work in wind and related industries. Most of those are tied to wind farms and in manufacturing. Construction, operation and maintenance are just behind. A wind turbine contains about 8,000 parts and can be up to 300 feet high, or the length of a football field. It's a big piece of machinery with three main parts: the blades, tower and boxes with the turbine's gears and other components.

On December 16, 2010 Energy Secretary Steven Chu announced that a partial loan guarantee for a $1.3 billion loan has been finalized to support the world's largest wind farm. The loan will finance the Caithness Shepherds Flat project, an 845 MW wind generation facility located in eastern Oregon sponsored by Caithness Energy, LLC and GE Energy Financial Services.

The project will use 338 GE 2.5 MW wind turbines, which are designed to provide high efficiency and increased reliability, and grid integration. Once completed, the project will sell 100 percent of the power and renewable energy credits generated to Southern California

Edison under 20-year fixed price power purchase agreements. The DOE, through the Loan Programs Office, has issued loan guarantees or offered conditional commitments for loan guarantees to support 16 clean energy projects totaling nearly $16.5 billion. Together, the 16 projects total over 37 million megawatt-hours of capacity, which will produce enough clean energy to power over 3.3 million homes.

A January 2010 NREL report assessed the wind speeds at 80 meter hub heights. The report indicates that a much larger wind resource is available than what is available at 50 meter heights used in the 2007 SB91 Report. The national and Colorado maps in Figure 36 indicate the wind resource at 80 meter hub heights.

To supplement the Colorado wind projects referenced earlier, the EIA data in Figure 38 lists almost 100 renewable electric generation facilities above 800 kW in the state. Not all of the facilities listed in Figure 37—primarily hydro facilities—qualify toward Colorado's RES, and the total in the figures do not reflect the approximate 75 MW of installed rooftop solar PV in Colorado.

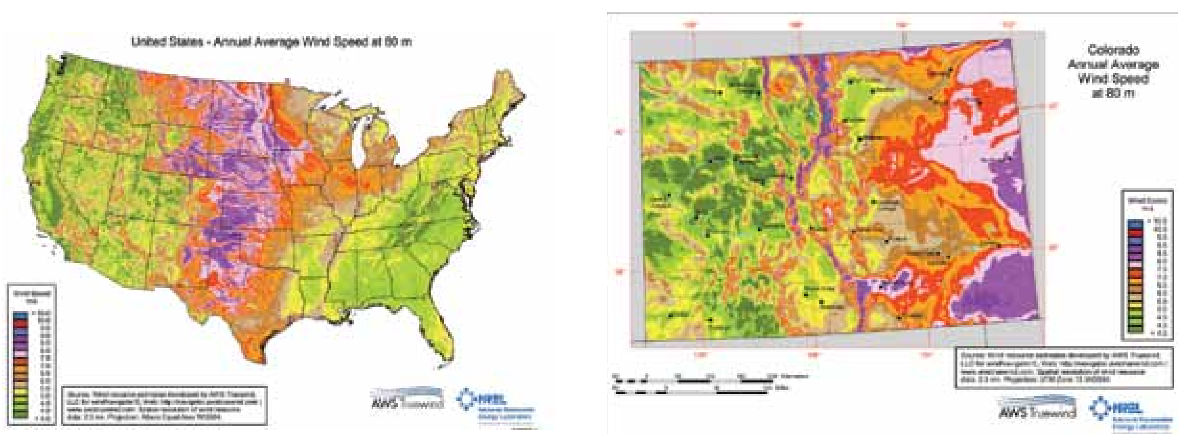


Figure 36: Annual Wind Speeds in the United States and Colorado

Source: National Renewable Energy Laboratory

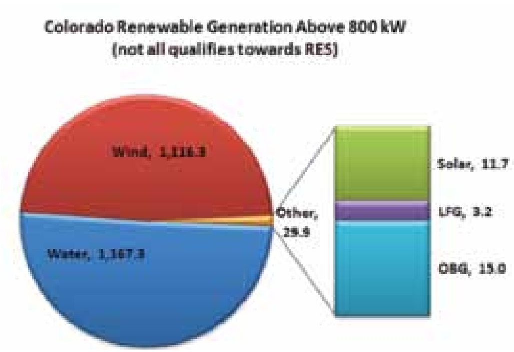


Figure 37: Colorado renewable generation above 800 kW

Source: EIA Form 860 data [69]

Solar Developments

Utility-scale solar energy development is steadily increasing in Colorado, but these projects are encountering challenges. The area in Colorado with the highest Direct Normal Insolation is the San Luis Valley, the site of two large PV facilities providing power to PSCo. A unique 30 MW concentrating PV plant is scheduled to be developed in the valley, and solar thermal electric plants are scheduled to be in operation in the valley within the next few years. However, the scale of solar development in the San Luis Valley is a function of the ability to deliver the power to the grid, and that ability has been delayed considerably by an out-of-state billionaire who has assembled a series of legal delaying tactics with the intention of preventing a high voltage line crossing a portion of his 170,000 acre private estate. A protracted 18 month application, hearing, and decision-making process at the PUC has resulted in a November 2010 recommended decision favoring granting PSCo and Tri-State their certificates of public convenience and necessity (CPCN) to build the $180 million double-circuit 230 kV line. With this delay, the in-service date has been moved from a goal of 2013 to 2015. A PUC decision is expected the first quarter of 2011. However, assuming that the PUC grants the CPCNs, the issue will then be reviewed by the U.S. Department of Agriculture, as part of an Environmental Impact Statement

UTILITY NAME	PLANT NAME	NAMEPLATE	OPERATING YEAR	ENERGY SOURCE
Babcock & Brown Partners LLC	Cedar Creek Wind	300.5	2007	WND
Boulder City of	Boulder Canyon Hydro	10	1911	WAT
Boulder City of	Boulder Canyon Hydro	10	1911	WAT
Boulder City of	Boulder City Betasso Hydroelectric	3	1987	WAT
Boulder City of	Boulder City Silver Lake Hydro	3.3	2000	WAT
Boulder City of	Boulder City Lakewood Hydro	3.5	2004	WAT
City of Aspen	Ruedi	5	1985	WAT
City of Lamar	Lamar Plant	4.5	2004	WND
City of Lamar	Lamar Plant	1.5	2004	WND
Colorado Golden Energy Corp.	Metro Wastewater Reclamation Disti	2	1985	OBG
Colorado Golden Energy Corp.	Metro Wastewater Reclamation Disti	2	1985	OBG
Colorado Golden Energy Corp.	Metro Wastewater Reclamation Disti	2	1985	OBG
Colorado Golden Energy Corp.	Metro Wastewater Reclamation Disti	2	1985	OBG
Colorado Golden Energy Corp.	Metro Wastewater Reclamation Disti	3.5	2000	OBG
Colorado Golden Energy Corp.	Metro Wastewater Reclamation Disti	3.5	2000	OBG
Colorado Springs City of	Ruxton Park	1.2	1925	WAT
Colorado Springs City of	Manitou Springs	2.5	1927	WAT
Colorado Springs City of	Manitou Springs	2.5	1939	WAT
Colorado Springs City of	Tesla	27.6	1997	WAT
Colorado Springs City of	Manitou Springs	1	2006	WAT
Denver City & County of	Williams Fork Hydro Plant	3	1959	WAT
Denver City & County of	Strontia Springs Hydro Plant	1	1986	WAT
Denver City & County of	Dillon Hydro Plant	1.8	1987	WAT
Denver City & County of	North Fork Hydro Plant	5.5	1988	WAT
Denver City & County of	Hillcrest Pump Station	2	1993	WAT
Denver City & County of	Gross Hydro Plant	7.8	2007	WAT
Denver City & County-Foothills	Foothills Hydro Plant	3.1	1985	WAT
Duke Energy	Kit Carson Wind Project	51	2010	WND
Enxco Service Corporation	Ridge Crest Wind Partners	29.7	2001	WND
FPL Peetz Table Wind Energy	Peetz Table Wind Energy	199.5	2007	WND
Invenergy Services LLC	Spring Canyon	60	2006	WND
Logan Wind Energy LLC	Logan Wind Energy	201	2007	WND
MMA Belmar Power LLC	Belmar	0.5	2008	SUN
MMA Belmar Power LLC	Belmar	0.5	2008	SUN
MMA Belmar Power LLC	Belmar	0.2	2008	SUN
MMA Belmar Power LLC	Belmar	0.2	2008	SUN
MMA Belmar Power LLC	Belmar	0.2	2008	SUN
MMA DAS Power	DIA	1.9	2008	SUN
P P M Energy Inc	Colorado Green Holdings LLC	162	2003	WND
P P M Energy Inc	Twin Buttes Wind Project	75	2007	WND
Ponnequin Acquisitions, LLC	Ponnequin Phase 1	5.2	1998	WND
Ptarmigan Res & Engy Inc	Vallecito Hydroelectric	2.5	1989	WAT
Ptarmigan Res & Engy Inc	Vallecito Hydroelectric	2.5	1989	WAT
Ptarmigan Res & Engy Inc	Vallecito Hydroelectric	0.8	1989	WAT

UTILITY NAME	PLANT NAME	NAMEPLATE	OPERATING YEAR	ENERGY SOURCE
Public Service Co of Colorado	Tacoma	2.2	1905	WAT
Public Service Co of Colorado	Ames Hydro	3.6	1906	WAT
Public Service Co of Colorado	Georgetown	0.7	1906	WAT
Public Service Co of Colorado	Tacoma	2.2	1906	WAT
Public Service Co of Colorado	Georgetown	0.6	1908	WAT
Public Service Co of Colorado	Salida	0.6	1908	WAT
Public Service Co of Colorado	Shoshone	7.2	1909	WAT
Public Service Co of Colorado	Shoshone	7.2	1909	WAT
Public Service Co of Colorado	Salida	0.8	1929	WAT
Public Service Co of Colorado	Palisade	1.5	1932	WAT
Public Service Co of Colorado	Palisade	1.5	1932	WAT
Public Service Co of Colorado	Tacoma	3.5	1949	WAT
Public Service Co of Colorado	Cabin Creek	150	1967	WAT
Public Service Co of Colorado	Cabin Creek	150	1967	WAT
Public Service Co of Colorado	Ponnequin	16.5	1999	WND
Public Service Co of Colorado	Ponnequin	9.9	2001	WND
Redlands Water & Power Comp	Redlands Water & Power	1.4	1931	WAT
Rio Blanco Water Conserv Dist	Taylor Draw Hydroelectric Facility	2.3	1993	WAT
STS Hydropower Ltd	Sugarloaf Hydro Plant	2.5	1985	WAT
SunE Alamosa1 LLC	SunE Alamosa	7.2	2007	SUN
SunE Alamosa1 LLC	SunE Alamosa	1	2007	SUN
U S Bureau of Reclamation	Green Mountain	13	1943	WAT
U S Bureau of Reclamation	Green Mountain	13	1943	WAT
U S Bureau of Reclamation	Estes	15	1950	WAT
U S Bureau of Reclamation	Estes	15	1950	WAT
U S Bureau of Reclamation	Estes	15	1950	WAT
U S Bureau of Reclamation	Marys Lake	8.1	1951	WAT
U S Bureau of Reclamation	Flatiron	43	1954	WAT
U S Bureau of Reclamation	Flatiron	43	1954	WAT
U S Bureau of Reclamation	Flatiron	8.5	1954	WAT
U S Bureau of Reclamation	Pole Hill	38.2	1954	WAT
U S Bureau of Reclamation	Big Thompson	4.5	1959	WAT
U S Bureau of Reclamation	Lower Molina	4.8	1962	WAT
U S Bureau of Reclamation	Upper Molina	8.6	1962	WAT
U S Bureau of Reclamation	Blue Mesa	43.2	1967	WAT
U S Bureau of Reclamation	Blue Mesa	43.2	1967	WAT
U S Bureau of Reclamation	Morrow Point	86.6	1970	WAT
U S Bureau of Reclamation	Morrow Point	86.6	1971	WAT
U S Bureau of Reclamation	Crystal	28	1978	WAT
U S Bureau of Reclamation	Mount Elbert	100	1981	WAT
U S Bureau of Reclamation	Mount Elbert	100	1984	WAT
U S Bureau of Reclamation	McPhee	1.2	1992	WAT
U S Bureau of Reclamation	Towaoc	11.4	1993	WAT
WM Renewable Energy LLC	DADS Gas Recovery	0.8	2008	LFG
WM Renewable Energy LLC	DADS Gas Recovery	0.8	2008	LFG
WM Renewable Energy LLC	DADS Gas Recovery	0.8	2008	LFG
WM Renewable Energy LLC	DADS Gas Recovery	0.8	2008	LFG

Figure 38: Wind, Water, Sun, Landfill, and Biogas generation in Colorado above 800 kW

Source: Department of Energy

process, resulting in further delays.

PSCo has downgraded its estimate of the amount of solar-generated energy that the line will carry, buoying critics who contend the project's environmental drawbacks outweigh its renewable energy benefits. PSCo has notified the PUC that it could commit to carry only about 60 MW of electricity from two planned solar plants in the region along the 150-mile-long transmission line. PSCo and Tri-State estimated that the line would transport up to 355 MW of renewable energy from solar arrays in the San Luis Valley to high-demand centers across the Front Range. "We can do the 60 MW, but that's where we plan to stop right now due to the uncertainty surrounding the transmission line pathway," said PSCo's Mark Stutz. Stutz said the company would re-evaluate the renewables situation in the fall of 2011 and adjust its estimates accordingly. The move comes despite the PUC's ALJ's ruling recommending that the PUC approve the transmission line.

On the distributed generation side of the solar development picture, Colorado's growth rate in PV development has been remarkable. In 2005 it is estimated that only 1 MW of PV was installed in the state. Thanks to the citizen initiated referendum, Amendment 37, and further increases in the state's RES, that number jumped to a cumulative 4 MW in 2006. The PV installations then jumped to a cumulative 14 MW in 2007. By 2008 there was a cumulative 36 MW of PV installed. In 2009, the number moved to a cumulative 59 MW. An impressive cumulative 103 MW of PV is now installed in Colorado , inclusive of distributed and utility-scale.

On December 14, 2010, Loveland-based Abound Solar Inc. said it has closed on a $400 million loan guarantee under the federal stimulus program to support expanded manufacturing in Colorado and Indiana. The thin-film solar panel manufacturer said it has raised $110 million in equity financing, for a total of $260 million since it was spun off from Colorado State University in 2007. It opened its production plant in Longmont in April 2009, and its research and development lab is in Fort Collins. The federal loan guarantee was intended to free up capital for Abound's production of thin PV panels using advanced cadmium-telluride semiconductor technology by reassuring lenders.

PSCo initiated an innovative solar augmentation experiment at the soon to be retired Cameo coal-fired generating station near Palisade. The company initiated an "Innovative Clean Technology" program approved by the

PUC. The project is a concentrating solar plant integrated with a conventional coal-fired power plant. The project is the world's first known demonstration of the hybrid solar-coal approach using parabolic-trough solar technology. The system is concentrating solar energy that provides heat to produce supplemental steam for power generation at Cameo Station's Unit 2. The experiment has gone well, as it has decreased the overall consumption of coal, reduced emissions from the plant, improved plant efficiency, and successfully tested the commercial viability of concentrating solar integration. Lessons learned at this pilot experiment may prove to be useful in other applications.

On December 15, 2010, Xcel Energy and SunEdison broke ground on a 54 MW PV project in New Mexico. The project is expected to be fully operational by the end of 2011 helping Xcel Energy to continue meeting New Mexico's renewable portfolio standard.

Evaluation objectives may include effectiveness in meeting the CO2 challenge, environmental performance, water-intensity, cost and price effectiveness, and the ability to be deployed in the time frame necessary to be effective.

Conclusion

Pursuant to Colorado's CAP, GEO's STAR project used the "carbon metric" as the appropriate key parameter to gain insight regarding what a potential electricity sector in Colorado would look like in the year 2050. Several simultaneous approaches are immediately available to be deployed by the electric industry to address climate change. This is particularly the case with regard to wide-scale deployment of utility-sponsored demand-side measures. Another effective course of action—and the reason more than half the states have passed renewable portfolio standards—is deployment of utility-scale renewable energy generation. This generation requires expansion of a high-voltage transmission infrastructure to deliver the power to the loads, however. Although there are acknowledged risks and adjustments will be necessary, retirement of the most intense CO_2 emitters is required. For this reason, the GEO and the Conceptual Planning Work Group have modeled the implications of retiring Colorado's fleet of coal-fired generation once they reach age 45. In addition, in concert with the above, the electricity sector needs to displace coal-fired generation with new state-of-the-art natural gas-fired generation. Other options exist, particularly CCS, distributed generation, energy storage, and nuclear power. When weighing these options, rigorous evaluation is required to determine if the options can meet certain objectives. These objectives may include effectiveness in meeting the CO_2 challenge, environmental performance, water-intensity, cost and price effectiveness, and the ability to be deployed in the time frame necessary to be effective.

4. Recent Colorado Legislative Actions

Overview

Given Colorado citizens' keen interest in environmental quality and the opportunities that achieving improvements in quality of life represent to the economy, the state has helped lead the way in creating a New Energy Economy. Since elected, Governor Ritter has signed 57 bills relating to clean energy. "We have a story to tell in Colorado. We're proud of that story," Ritter said at the November 2010 Green Intelligence Forum in Washington, D.C. "We don't think it's the end of that story at all. It's really only the beginning. It is perhaps a template for other states to look at." The governor discussed how Colorado has developed an ecosystem from clean energy that goes from the laboratory to production. In tandem with the legislature, the governor has worked to diversify the state's energy portfolio, tying in jobs and finding a way to frame climate change. Most recently, two pieces of legislation, discussed below, have been particularly important in reshaping the state's electric power future.

Figure 39: Governor Ritter Signs the Renewable Energy Standard into Law

Source: www.colorado.gov/governor/ [70]

Colorado's Renewable Energy Standard (HB10-1001)

On March 22, 2010 Colorado took another historic step forward in the New Energy Economy when the governor signed HB10-1001 into law (Figure 39). The act is the latest in a progression of improvements to Colorado's Renewable Energy Standard.[71] The act requires that Colorado's IOUs reach a minimum of 30 percent renewable electricity by 2020 and creates a "carve-out" for DG. This will create thousands of jobs during the next decade, and the DG requirement is expected to result in the installation of up to 100,000 solar rooftops. Colorado's RES is the second highest in the nation and the highest in the Rocky Mountain West. The law directs the PUC to consider "best value" factors such as employment of Colorado workers when approving resource acquisitions for regulated utilities. It also creates a certification standard requirement for solar installers.

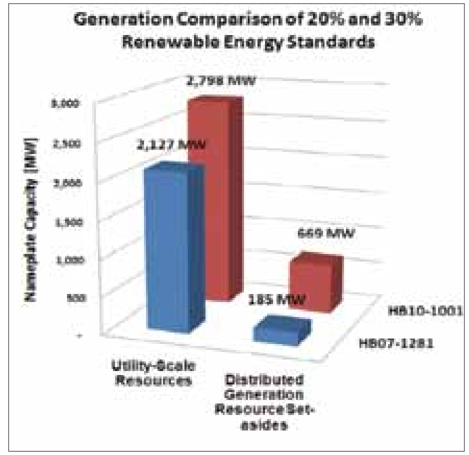


Figure 40: Generation Comparison of 20% and 30% Renewable Energy Standards

Source: GEO's website: www.rechargecolorado.com

Incremental Market Changes Resulting from HB10-1001

The law creates a total statewide demand of approximately 3,500 MW of renewable energy. Figure 40 shows that of this, approximately 2,800 MW is utility-scale renewable energy, and approximately 700 MW will be DG, likely primarily PV technology.

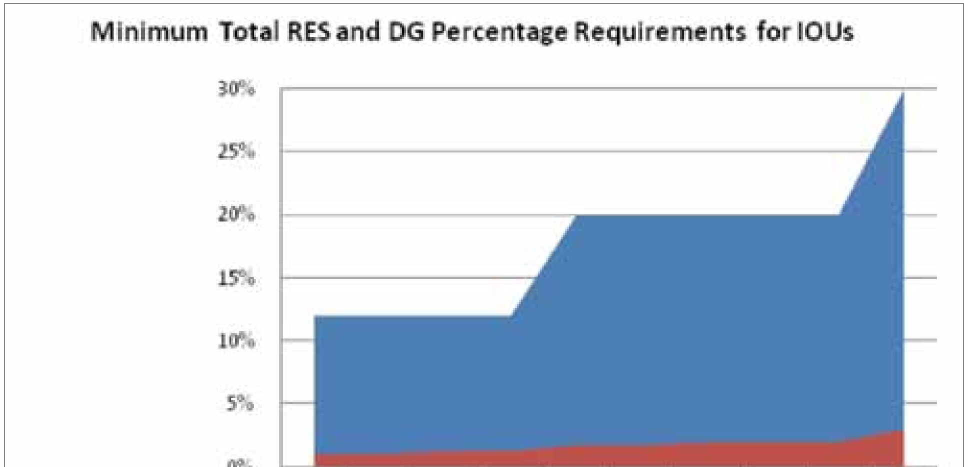
As a result of Amendment 37 and the steady increase in the state's RES, the number of solar companies doing business in Colorado increased from 50 in 2004 to more than 400 today. The retail DG portion of the RES, in particular, is a strong job creation engine. Since more labor is involved in customer-sited installations, this leads to both a greater economic impact and higher installation costs per megawatt installed. With the fourth–highest concentration of renewable energy and energy research employees in the country, Colorado employs more than 90,000 people either directly or indirectly in the new energy sector.[72] Companies such as Vestas Wind, SMA, Ascent Solar, Abound Solar, SunRun, SolarCity, and Zephyr have established locations in the state, in part, to take advantage of Colorado's high RES.

HB10-1001 Policy Components

The law[73] creates the utility-scale RES described earlier and the requirement that 3 percent of electric sales from Colorado's two IOUs come from renewable DG by 2020.

The 30 percent renewable energy generation standard and the 3 percent DG requirements include the three phases as shown in Figure 41. Actual utility compliance plans will demonstrate more orderly market growth with the objective of exceeding minimum compliance ahead of the 2020 goal.

The law specifies that IOUs are to be governed by a 2 percent retail rate impact cap on incremental costs for the purchase of renewable generation.



	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Total Renewable Energy	12%	12%	12%	12%	20%	20%	20%	20%	20%	30%
Renewable DG	1.00%	1.00%	1.25%	1.25%	1.75%	1.75%	2.00%	2.00%	2.00%	3.00%

Figure 41: Minimum Total RES and DG Percentage Requirements for IOUs

Source: Source: GEO www.rechargecolorado.com [74]

- **Renewable Distributed Generation:** In addition to the large increase (from 20 percent to 30 percent) in the RES, a significant policy change from HB07–1281 to HB10–1001 was the transition from a solar–only IOU carve-out of 0.08 percent (4 percent of the 20 percent RES) to a DG requirement of 3 percent of electricity sales (3 percent of 100 percent of IOUs' total electricity sales). DG includes the categories of retail DG (RDG) and wholesale DG (WDG). RDG is customer–sited (behind the meter) and subject to a net metering cap. WDG, or non–customer-sited DG, is any renewable resource less than 30 MW.

- **Expanding Markets for Distributed Generation:** With the passage of HB10-1001, Colorado is a prime location for solar companies seeking a sustained, orderly development marketplace to provide DG services ranging from manufacturing to installation.

- **Market Segmentation:** The new law directs IOUs to acquire half of all DG from retail sources (RDG) and half from wholesale sources (WDG), ensuring greater market certainty for renewable energy developers. Within RDG, the law further directs that the funding spent to achieve 50 percent of the DG standard should be allocated according to how the retail and wholesale sectors pay into the Renewable Energy Standard Adjustment (RESA).[75] For example, revenue collected from PSCo's customer classes is roughly split between 40 percent residential and 60 percent nonresidential customers. Therefore, 40 percent of the funding used by the utility to purchase RDG must be spent in the residential customer class. The market segmentation structure provides renewable energy manufacturers, developers, and installers the assurance to invest in the state.

- **RES Compliance Multipliers:** The RES legislation retained what has been Colorado's 1.25x compliance multiplier for WDG, but removed it for RDG. One renewable energy credit (REC),[76] the unit of compliance with the RES, equates to 1.25 RECs generated from WDG. In–state compliance multipliers are an effective mechanism to spur development of a specific type of project or energy resource to be constructed in the state. By developing in-state resources, a utility contributes to the overall economic vitality and strength of Colorado communities.

Paying for the 30 Percent RES within the RESA 2 Percent Retail Impact Cap

Total costs of HB10-1001 are limited by a RESA 2 percent retail rate impact cap. The law specifies that IOUs are to be governed by a 2 percent retail rate impact cap on incremental costs for the purchase of renewable generation. To date, all the RESA funds, roughly $65 million per year, have been spent on PV system installations rather than on wind. Because wind is competitively bid into the utility supply system as a least-cost resource, wind does not trigger an incremental cost above traditional resources. Given the 2 percent retail rate impact cap, the RESA provides a finite amount of funding. A portion of the RESA is spent on incentives to homes and

HB10-1365 is primarily driven by the need to reduce nitrogen oxide (NOx) emissions (ground level ozone) by 70 percent to 80 percent in the Denver Metro and the North Front Range Ozone Nonattainment Area.

businesses to lower the cost of installing PV systems and to purchase RECs to meet the 30 percent RES and 3 percent DG requirements. The following changes to the RESA requirements will allow utilities to better use RESA funds:

- **Advancing or Securitizing RESA Funding:** This approach to RESA funding will allow IOUs to earn their after-tax weighted-average cost of capital for borrowing forward-future RESA collections. This allows funding to be brought forward to today to build generation for tomorrow. Addressing RESA funds is subject to the 2 percent annual rate impact cap.

- **Standard Rebate Offer Level:** Amendment 37 established a $2-per-watt standard rebate offer (SRO) for solar. The SRO is one of a two-part utility incentive for solar projects. Total rebates from the utilities include both the SRO and the price offered for the purchase of 20 years of solar RECs (SRECS) and SO–RECs, or on-site S-RECs. IOUs have the discretion to reduce SREC and SO–REC payments based upon market conditions, but until HB10–1001, the SRO was a statutory minimum offer of $2 per watt. In PSCo service territory, the SO-REC started at $2.50 per watt in 2007 and is now $0.45 per watt. Granting the PUC authority to reduce the SRO upon IOU request will bring needed flexibility to SRO and REC pricing.

- **RESA Contributions for Existing Solar Customers:** HB10–1001 addresses a cross-subsidization issue that occurs when customers who have net metering are at net–zero of utility generated power. The new law directs the PUC to determine a fair payment for these customers, rather than charging them for not using energy. The 2 percent RESA rider covers all incremental costs of integrating renewable energy into the grid, including intertie lines and infrastructure.

Best Value Language

The RES contains "best value" language. The law references keeping utility construction jobs in Colorado, accounting for availability of training programs, employment of Colorado workers, competitive wages, and benefits offered to workers. The best value language considers a comprehensive set of costs and benefits to the bill payer, which include environmental and sustainability factors, such as availability of water.

Solar Certification

HB10–1001 will generate thousands of new solar projects and and new jobs in Colorado during the next decade. A solar certification provision in the law ensures that the safety of installers, customers, and utility linemen is protected by requiring a minimum workmanship standard. One in four installers on a PV job site must have a North American Board of Certified Energy Practitioners (NABCEP) certification, which is a widely recognized standard for PV installation certification.

Clean Air-Clean Jobs Act (HB10-1365)

HB10-1365, the Clean Air-Clean Jobs Act, was signed into law on April 19, 2010,[77] in anticipation of federal Clean Air Act requirements that will require improved environmental performance in the electricity sector in Colorado's northern Front Range, which is in noncompliance with ground-level ozone standards. Unless the area develops a credible EPA-approved State Implementation Plan, the federal government could impose its plan for compliance, which could be accompanied by the risks of fines and a withholding of federal highway funds.

HB10-1365 is primarily driven by the need to reduce nitrogen oxide (NOx) emissions (ground level ozone) by 70 percent to 80 percent in the Denver Metro and the North Front Range Ozone Nonattainment Area (see Figure 42) by December 2017. These reductions are necessary to protect public and environmental health. Sources of NOx emissions are largely caused by electric power generation plants operated by Colorado IOUs, principally PSCo. The act calls for PSCo to retire the lesser of at least 900 MW of coal-fired electric generating capacity, or 50 percent of the utility's coal-based capacity, not including capacity that it already was planning to retire before Jan. 1, 2015.

Figure 42: Current Denver Metro/North Front Range Ozone Nonattainment Area
Source: Denver Regional Council of Governments [78]

The Colorado legislature recognized that a proactive, coordinated effort to reduce emissions from coal-fired power plants—rather than a piecemeal approach—will allow the state to more cost-effectively comply with federal law and plan for timely and efficient integration of replacement resources.

Clean Air-Clean Jobs Act Topics

The act increases reliance on natural gas to meet the state's electricity requirements and stipulates that changes that occur in the generation mix to meet emission reduction targets shall not compromise the reliability of the electricity service provided to customers. Achieving the necessary NOx reductions is most cost-effectively accomplished by replacing coal-fired generation with gas-fired generation or low-emitting sources. Figure 43 compares certain environmental performance characteristics of electric generation.

The act requires the PUC to incorporate the judgment of the Colorado Department of Public Health and Environment (CDPHE) regarding whether the utilities' plans meet "reasonable and foreseeable" air quality regulations in addition to the NOx reduction requirement in the legislation. Following

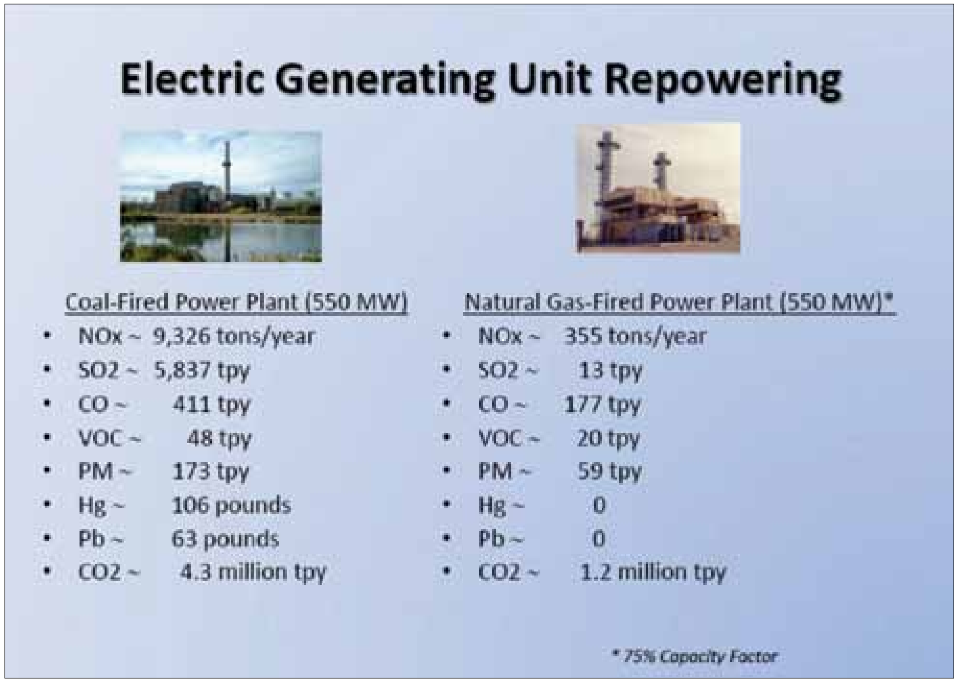


Figure 43: Environmental Performance - Coal-Fired and Gas-Fired Generation
Source: Colorado Department of Public Health and Environment

review by the Colorado General Assembly, the plan will be incorporated into state and federal air regulations. The act's implementation deadline requires that all actions associated with compliance occur by Dec. 31, 2017.

The act drew wide political and public support and limited opposition. The bill passed the House of Representatives on a vote of 53-12. The bill passed the Senate on a vote of 20-13, with one abstention. Supporters included the Governor's Office, PSCo, the natural gas industry, environmentalists, public health advocates, and others. Opponents included the coal mining industry and communities that depend upon coal mining.

A bipartisan research team of Public Opinion Strategies (R) and Fairbank, Maslin, Maullin, Metz & Associates (D) examined public perceptions of PSCo's plans to comply with the act. Data demonstrate overwhelming voter support for shifting Colorado's electricity generation from coal to renewable energy, energy efficiency efforts, and natural gas. Research also shows how support levels change after citizens learn the cost implications of the proposal.

Key findings of the polling include the following:

- Voters strongly prefer (79 percent to 17 percent) renewable energy and natural gas over coal as an energy source for Colorado.
- Seventy-six percent of poll respondents support PSCo's plan to shift from coal and toward natural gas and renewable energy such as wind and solar; they also support an increase in energy efficiency efforts.
- This support is strong among all subgroups, including Democrats (89 percent), Independents (73 percent), Republicans (64 percent) and Denver Metro (78 percent) and West Slope residents (70 percent). No subgroup demonstrated less than 62 percent support for the proposal.
- Support remains solid after voters hear about cost implications of the plan. Seventy-one percent support it with 1 percent increase in customer prices, and 68 percent support it with a 3 percent increase.

Energy Outreach Colorado, who are advocates for Colorado's low-income energy consumers stated that "in the long run Clean Air, Clean Jobs may wind up saving money for the state's poorest residents.

- Nearly two-thirds (64 percent) of Coloradans reject recent coal industry objections and agree that these changes will yield critical health benefits for Colorado.
- Enthusiasm for this proposal may be rooted in long-held concerns about air quality in Colorado—nearly four in ten (38 percent) respondents reported air pollution as their top environmental concern.

Although there is general agreement that the legislation represents a major advance toward cleaning the air in the northern Front Range and recognition that it will replace a limited number of coal-related jobs with jobs in the natural gas industry, differing views have been presented to the PUC regarding both the details of plan implementation and its timing. Because the legislation focuses primarily on converting coal generation to natural gas, two of the main industries that support the coal industry—mining and rail—actively opposed the act. Representatives from these constituents cite loss of jobs and negative impacts on certain local economies in parts of western Colorado, where coal mining is a major part of commerce. These viewpoints are counter-balanced by views that place such concerns into a wider context, including a broader economic analysis and the need to protect public and environmental health.

The Leeds School of Business at the University of Colorado was commissioned by PSCo to study the impact of its plan to comply with the Clean Air—Clean Jobs Act. In its 47-page report, *Economic Impacts of Implementing the Colorado Clean Air-Clean Jobs Act under Different Scenarios,"*[79] the school examined four scenarios, each of which indicates positive economic benefits resulting from construction, operations, employment (operating and construction), capital expenditures, and rate requirements. In some cases, increases in rate requirements or decreases in operating expenditures and employment had negative economic impacts; however, these declines were always dwarfed by increases elsewhere (e.g., construction). Energy Outreach Colorado, who are advocates for Colorado's low-income energy consumers stated that "in the long run Clean Air, Clean Jobs may wind up saving money for the state's poorest residents. EPA regulation of aging coal plants is expected to add huge costs in terms of scrubbing technology meant to make the facilities more compliant with federal clean air laws."

On Aug. 13, 2010, PSCo filed its preferred scenario which would have resulted in nearly $1.8 billion in economic benefits from 2010 to 2026 ($784.4 million direct, $301.5 million indirect, and $696.7 million induced). This scenario was adjusted by PSCo in a subsequent portion of the proceeding; the economic results are similar, however.

Environmental Improvements Expected from the Act

The most important environmental consideration of the plan may be the required reduction of at least 70 percent to 80 percent in NOx emissions from 2008 levels. Additional air quality improvements will result from reduction of emissions of other air pollutants. Other expected benefits include increased use of natural gas to further displace coal generation beyond immediate repowering projects, and an enhanced ability to meet federal or state clean energy requirements.

Before filing the plan to comply with the federal and state environmental standards, PSCo was required to consult extensively with the CDPHE, which must provide final approval. The department was required to determine whether certain new or repowered electric generating units proposed in the plans will emit more than 1,100 pounds of CO_2 per MWh and whether the plans comply with applicable requirements of federal and state clean air laws.

One example of an affected plant is PSCo's Cherokee Station, located just four miles north of downtown Denver. The plant emits more than 21,000 tons of SOx and NOx and 5,716,000 tons of CO_2 annually and consumes more than 2.5 billion gallons of water from the South Platte River, which, for much of the year, leaves only a small amount of water flow below the power plant's intake. Testimony was filed that indicates retiring the plant may help restore the natural flow and ecosystem of that portion of the South Platte River.

Economic Considerations and Provisions of the Act

The act also allows regulated utilities to enter into long-term natural gas supply contracts. This type of contract historically has been rare in utility operations. Financial markets have often viewed long-term natural gas contracts as risky due to concerns about whether utilities would be able

As an additional benefit, early reductions of greenhouse gas emissions will be counted as voluntary for purposes of early reduction credits under federal law.

to fully recover all associated costs for the contract. This viewpoint negatively affected the perceived financial risks and creditworthiness of regulated utilities in the eyes of financial ratings agencies. The legislation acknowledges the importance of giving financial markets the confidence that utilities will be able to recover costs associated with such long-term contracts. The act also promotes greater latitude for the PUC to work with utilities to proactively manage the costs associated with complying with the legislation.

Because of the legislative intent, the commission's decision was determined to some extent on whether implementation of the act promotes economic development in the state and on the degree to which it helps protect customers from future electricity cost increases. Another driving factor behind the act is the cost associated with the effects of coal-based electricity generation on health. For example, testimony has been filed estimating that neighboring communities will save $90 million in air pollution and health damages when the Cherokee Station plant is retired.

Colorado's Air Quality Control Commission also will consider incorporating the emissions reductions derived from the plans into the regional haze element of the state's implementation plan filed with the EPA. As an additional benefit, early reductions of greenhouse gas emissions will be counted as voluntary for purposes of early reduction credits under federal law. The PUC has authority to approve interim rates that take effect no later than 60 days after a rate increase filing that may stem from approving the Clean Air-Clean Jobs Act plan, and the PUC can require PSCo to issue rebates to customers if a final rate is lower than what may be charged as an interim rate.

Figure 44: PSCo Plants Analyzed for Retirement

Source: Public Service Company of Colorado[80]

Summary of PSCo and BHE Responses

After the act was passed, PSCo began the process of identifying coal units that would be included in the company's plan to meet emission reduction requirements. PSCo considered the age of plants, variable operating costs, location, ownership, existing emission controls, available control technologies, and foreseeable emission requirements to determine which units would be the most suitable candidates for emission controls, conversion to gas, or retirement.

Based on PSCo's evaluation of its existing coal generation fleet, eight plants were determined to be the best candidates for one of three broad courses of action to help the utility comply with the act: 1) facility shutdown, 2) fuel switch, or 3) adding emission control equipment. The candidate facilities, totaling 1,801 MW in generating capacity, are shown in Figure 44.

In PSCo's original Aug. 13, 2010, filing, the resulting plan, referred to as Scenario 6.1.E, the utility stated that its preferred scenario balances the overall cost with other key factors, including providing the necessary generation support to the central Denver transmission system;

High-efficiency combined-cycle natural gas generation was selected as the replacement technology because it is both cost-effective, flexible, and can help integrate the variable amounts of wind and solar as they are introduced to the grid.

maintaining a reliable electricity supply; and modernizing key components of the utility's generation fleet. PSCo stated that it selected the lowest-cost alternative, using traditional resource planning assumptions. The company stated that, when the plan is fully implemented, it will reduce NOx emissions by approximately 89 percent and CO_2 emissions by nearly 30 percent. PSCo also stated that its plan minimizes both the short-term and long-term customer rate impacts. Table 45 summarizes the company's recommended plan and the timing of proposed actions.

During the course of its analysis, PSCo determined that shutting down Cherokee 1 and 2, followed by 3, made the most operational sense from a generation capacity and cost perspective. The company's focus then shifted to emission reduction options for the larger Valmont 5 and Cherokee 4 generation units; timing was the most critical issue. Retiring Valmont 5 in 2017 proved to be less costly than shutting it down at an earlier date. One item associated with retiring Cherokee 4 was having the 1x1 combined cycle replacement generator online. While this was expected to occur as soon as 2018, the company decided to extend the timetable by four years to 2022. In the meantime, PSCo preferred early NOx reduction of approximately 30 percent from Cherokee 4 by installing a selective non-catalytic reduction system that can be added relatively quickly.

Subsequent to the company's initial filing, numerous parties advocated a more rapid retirement schedule, referencing the legislation's timeline for compliance as "by the end of 2017." On Sept. 29, 2010 the PUC determined that, because the Clean Air-Clean Job Acts specifies full implementation of the plan must occur by Dec. 31, 2017, it cannot consider actions in the plan forecasted to occur after that date. Accordingly, on Oct. 25, 2010, PSCo filed a revised plan to address earlier retirement of the Cherokee 4 unit. The company's revised plan entirely replaced its previous filing. PSCo estimated that its initial plan would cost $1.1 billion, and that the new scenario for converting to natural-gas at Cherokee would increase the total cost to $1.3 billion. Although not initially preferred by PSCo, a new scenario was favored by most of the parties in the case.

In preparing the plan, PSCo determined that it was critical to ensure the continued reliable operation of the generation and transmission systems. The existing Denver metropolitan transmission system was designed around the Cherokee and Arapahoe generation facilities. Both sites contain baseload units that operate on a continuous, uninterrupted basis and provide both power generation and voltage support to the grid. Therefore, PSCo determined that cleaner replacement generation must be online and ready to serve a similar role to maintain the safety and reliability of the transmission system. High-efficiency combined-cycle natural gas generation was selected as the replacement technology because it is both cost-effective, flexible, and can help integrate the variable amounts of wind and solar as they are introduced to the grid. In total, the company plans to retire just over 900 MW of coal-based generating capacity and replace it with efficient combined-cycle gas generation.

The plan incorporates a long-term gas contract with Colorado-based gas suppliers. During the time between when Cherokee 1 and 2 are shuttered and the new 2x1 natural gas combined-cycle plant is built, the utility plans to increase utilization from existing natural gas-powered plants. According to PSCo, this plan achieves improved system reliability because the planned new generation will replace aging coal units located within the load center, thus avoiding the need for new high-voltage transmission lines. The total price for the company's plan is estimated to be $1.3 billion, with the expectation that this price will result in a rate impact of approximately 1.5 percent per year.

Black Hills proposed retiring its two coal-fired units in Cañon City and building a unit in Pueblo fired by natural gas. BHE says the utility would need to determine terms if it were to buy power from others instead of building a new unit. BHE said running the units on wood pellets would be too costly.

Summary of Perspectives of Certain Stakeholders

The Clean Air-Clean Jobs docket at the PUC[81] attracted many intervenors that produced detailed information for the commission to consider. It is estimated that more than 2,000 separate documents were entered into the record by the conclusion of the docket. Positions of certain stakeholders are briefly summarized below.

Generating Plant	Action
Cherokee	2011 – Retire Cherokee 2 and convert the electric generator to a synchronous condenser 2011 or 2012 – Retire Cherokee 1 after the conversion of Cherokee 2 to a synchronous condenser 2012 – Install a selective noncatalytic reduction system (SNCR) to control NOx emissions on Cherokee 4 2015 – Construct a gas combined cycle unit using land that is currently Cherokee 1 and 2 2017 – Retire Cherokee 3 2022 – Construct a gas 1x1 combined cycle unit using land that is currently Cherokee 3 2022 – Retire Cherokee 4
Arapahoe	2013 – Retire Arapahoe 3 as a coal-burning unit, and convert the electric generator to a synchronous condenser 2013 – Fuel switch Arapahoe 4 from coal to natural gas
Pawnee	2014 – Install a selective catalytic reduction system (SCR) to control NOx emissions and a flue gas desulphurization system ("scrubber") on Pawnee 1
Hayden	2015 – Install an SCR to control NOx emissions on Hayden 1 2016 – Install an SCR to control NOx emissions on Hayden 2
Valmont	2017 – Retire Valmont 5

Figure 45: PSCo's Preferred Plan, Scenario 6.2J

Boulder

In its final statement of position, Boulder "encourages the PUC to approve 6.2J as the proposed plan that is most protective of human health and the environment and the most cost-effective over the thirty-six year planning period from 2010 to 2046. As the analysis below indicates, Scenario 6.2J outperforms all other plans in terms of oxides of nitrogen emissions."

Colorado Department of Public Health and Environment

In its final statement of position, the department "determined that regional haze and ozone were the primary current and reasonably foreseeable air pollution requirements under the federal and state lean Air Act. EPA has issued a letter to Colorado and other states indicating that such SIPs must be submitted to EPA by January 2011. If the Regional Haze SIP is not timely submitted to EPA, the agency will take over the Department's regional haze program and regulate the utilities and other large sources of NOx and SO2 in the state through an EPA-promulgated Federal Implementation Plan (FIP). In addition, the Department determined that requirements on sulfur dioxide (SO2) and mercury were also reasonably foreseeable emission reductions in the long term."

Colorado Independent Energy Association

Colorado Independent Energy Association (CIEA), representing 40 independent power producers (IPPs), challenged PSCo's plan to build its own gas-fired plants, arguing that it would be less expensive for the utility to buy power from IPPs. CIEA stated that the General Assembly explicitly made HB10-1365 a prescribed and limited action. The group posits that the legislation was intended to address a specific, one-time challenge to Colorado's utilities, with explicit temporal limitations, given the import of the air quality challenges to be met. CIEA stated that the most straightforward, least-cost, least-risk plan to achieve the necessary retirement of Cherokee 4—while preserving PSCo system reliability—is to approve a modified plan that uses 308 MW of IPP-owned existing gas resources in the Boulder, Denver, and Greeley areas as replacement power for Cherokee 4.

Colorado Oil and Gas Association

Colorado Oil and Gas Association (COGA) sees the act as critical to get the PUC and the State Air Quality Control Commission to work together to proactively meet pending federal regulations in a business-friendly, cost-efficient manner. COGA believes the Clean Air-Clean Jobs Act coordinates the efforts to reduce emissions from coal-based power plants, which will ensure the least economic impact on customers. COGA also reiterates that gas prices will not drive up customer costs because the legislation allows for long-term, fixed-priced contracts with gas producers, moving PSCo away from indexed contracts with price volatility. COGA also states that the dramatic increase in known domestic gas reserves now provides more than a 100-year supply of natural gas, and that Colorado has abundant natural gas resources. COGA also believes the legislation will be beneficial to the Colorado economy, estimating that the act could create 400 new natural gas industry jobs and an additional $24 million in taxes annually.[82]

Denver Public Schools

In its final statement of position, the Denver Public Schools states: "Specifically, DPS supports Scenario 6.2J because it is the best scenario with respect to fulfilling all requirements of HB10-1365. DPS oppose Scenario 5B because it would require PSCo to spend approximately $170 million for pollution controls on a 42-year-old coal unit."

Gas Intervenors

A coordinated group of natural gas producers filed as one entity, denominated as the "gas interveners." Three of the county's largest natural gas producers—EnCana, Anadarko Petroleum, and Chesapeake Energy—promoted a plan to use even more natural gas than PSCo proposed. The gas interveners favored an early conversion of the Cherokee coal-fired generating plant to natural gas units, followed by retirement of these units after new natural gas combined-cycle plants have been constructed. The argument for this action is that low prices of natural gas, combined with the near-term air quality benefits from conversion, justify the relatively low-cost expenditures involved in converting targeted boilers at the Cherokee plant site. Susan Arigoni, PSCo vice president for fuels, reported that PSCo projects its use of natural gas for electricity generation will increase 50 percent to about 75 billion cubic feet annually in 2018 because of the Clean Air-Clean Jobs Act. In their final statement of position, the gas companies who intervened state: "This Commission and PSCo have the opportunity to make a huge positive difference with cost-effective efforts to retire outmoded dirty power plants by replacing them with cleaner burning natural gas and renewable energy sources. Colorado can act positively and assure that it decides its own future. With federal action on the horizon, Colorado and its Public Utilities Commission must make this a success. Extending the life of Cherokee 4 to 2031 with a $175,000,000 scrubber would be failure. Through its efforts, with the Commission's support, PSCo's new generation units can produce the greatest improvement in Front-Range air quality in decades, while protecting the interests of the whole State of Colorado and looking forward to the future using clean fuels and clean fuels backing-up renewable energy sources."

Governor's Energy Office

GEO advocated that PSCo should meet or exceed the provisions of the act, advocated for retirement of the Cherokee 4 unit before the end of 2017, and for replacement of that generation with an emissions profile at least as clean as a new gas-fired resource, achieving a major reduction in SOx, NOx, mercury, and CO_2 . GEO agreed with various parties that addressing these pollutants will contribute to improved air quality and public health in Colorado. The office's primary position is that early retirement of coal to natural gas at Cherokee will allow PSCo to plan for and meet increasingly stringent EPA air quality regulations. GEO prefers this strategy rather than delaying retirement and running the risk of more expensive pollution controls that may have to be considered in the future. GEO testified that "reasonably foreseeable" regulations identified in the legislation should include constraints on carbon emissions and that the level of carbon emissions should be a factor in determining both closure and replacement scenarios. All parties to the case would agree that long-term natural gas prices are fundamental variables to the overall cost/benefit calculations to any of the scenarios outlined in this proceeding. A ruling that conditionally approves the purchase agreement will send a clear and direct market signal to all stakeholders that a long-term fuel contract stabilizing natural gas input prices will be achieved."

Leslie Glustrom

In her final statement of position, Ms. Glustrom offered the following conclusions: 1) Coal costs are increasing at about 10 percent per year; Xcel's models run at coal cost escalations of less than 2 percent per year should not be accepted as "the truth;" 2) Scenarios that call for extending the life of Xcel's Colorado coal plants) is likely to cost significantly more than Xcel's models have predicted due to future increases in coal costs above those modeled by Xcel; 3) It would be imprudent to add pollution controls to Xcel's Colorado coal plants until a credible long-term study has been conducted of future coal costs and supply issues and the study has been reviewed by interested parties; 4) Continuing reliance on coal has many environmental and social costs and increased litigation risk and should be avoided; 5) Natural gas better supports increased levels of renewable energy than coal plants that do not cycle easily; 6) Natural gas costs can be avoided by adding cost-effective efficiency and renewable energy; coal costs are not easily avoided.

Office of Consumer Counsel

In its final statement of position, the Colorado Office of Consumer Counsel "requests that the Commission 1) approve Public Service's Recommended Plan 5B, 2) approve the Natural Gas Agreement without making any decision on contract defaults, and 3) defer a cost recovery decision to a future docket and require Public Service to file a cost recovery application."

Public Service Company of Colorado

In its final statement of position, the company said: "We respectfully request that the Commission approve the Company's recommended plan Scenario 5B. Of all the scenarios reviewed in this docket, this plan scenario represents a coordinated approach to achieving the significant air emission reductions by the end of 2017 mandated by the CACJA and to meeting the current and reasonably foreseeable requirements of the federal Clean Air Act at the lowest cost for our customers, irrespective of whether or not carbon dioxide emissions are regulated within the next decade. Public Service's second choice would be the adoption of Scenario 6.2J. Because this scenario has a somewhat greater cost than Scenario 5.B, it is not our recommended approach. Next Public Service respectfully requests Commission approval under of the Anadarko contract, irrespective of which scenario the Commission adopts. The record in this case clearly establishes that the Anadarko contract, with its projected fuel savings, appears to be beneficial to consumers and in the public interest."

Peabody Energy

The coal company questions whether the PUC should consider "current and reasonably foreseeable" Clean Air Act requirements as met with a carbon price of $20 per ton, escalating at a 7 percent annual rate. Peabody points to the Nov. 2, 2010, elections as an indicator that Congress will not pass climate legislation in the foreseeable future. Peabody urged the commission to extend the life of the coal plants, arguing they already have been amortized and use low-cost fuel. "If the Commission persists in approving a Plan by December 15, 2010 despite the severely compromised evidentiary record in this proceeding, then it should approve Benchmark 1.0 as the only Plan best satisfies all of the statutory criteria. The Commission should make a finding that Public Service has not met its burden of proof by a preponderance of the evidence with regard to Scenario 6.2J, and, that Public Service falls woefully short in proving that its 6.2J alternatives are superior and indeed fails to show that Scenario 6.2J is even feasible."

PUC Staff

In Staff's final statement of position, they stated: "Each of the alternative scenarios very effectively reduce NOx emissions by the end of 2017, and in Staff's opinion no scenario stands out as being materially superior in this regard. Clearly, the biggest question mark in this regard is Scenario 6.2J. The Company repeatedly and unequivocally asserted that it could not retire Cherokee Unit 4 and construct all necessary replacement capacity at the Cherokee site by the end of 2017 while preserving system reliability. The Company also cited significant execution risk associated with any such endeavor. The Company now asserts that it can construct both a 2x1 CC and a 1x1 CC at the Cherokee site by the end of 2017 while preserving system reliability."

Southwest Generation

In its final statement of position, Southwest Generation said: "Scenario IPP2 meets the statutory criteria of H.B. 1365: it has a superior emissions performance; it is the most economical; it carries the least amount of risk of all of the scenarios that retire Cherokee 4 by 2017; it reinforces system reliability; it integrates existing natural gas resources, as explicitly required for consideration under the Act; it provides unique economic and environmental benefits; and PSCo has agreed that Scenario IPP2 is feasible. Scenario 6.2J, is an unacceptably risky scenario, technically, economically and legally. Because of the space constraints on the Cherokee site and the Act's requirement of full implementation by the end of 2017, it is questionable whether implementing Scenario 6.2J can be done within the budget and schedule identified by PSCo."

Thermo Power and Electric

In its final statement of position, Thermo Power and Electric states: "IPP 2 achieves the emission reductions goals with an emissions profile equal to or greater than any than any scenario before the Commission. IPP 2 is the most cost-effective, risk-adjusted scenario. The Commission should narrow the field of final scenarios to IPP 2, 5B , and 6.2J."

Western Resource Advocates

Western Resource Advocates (WRA) stated that it is encouraged by PSCo's plan, and it sees the Clean Air-Clean Jobs Act as helping put Colorado on a path toward cleaner air and improved public health. The act provides relief for public health concerns over air pollution by establishing mechanisms to replace aging coal—fired power plants in Colorado with cleaner sources of energy, further enhancing the state's position as a leader in developing cleaner sources of energy. WRA also indicated that an additional benefit of retiring the plants would

"The state of Colorado and its electric consumers are much better off because of our actions in approving these plans." – PUC Chairman Ron Binz

be to help conserve scarce Colorado water resources that are consumed during the process of producing coal-fired electricity. WRA said: "Issues of reliability, costs, and economic impacts must all be considered. But making this transition promises enormous benefits for Colorado, most notably cleaner air and a healthier environment, but also a more balanced, less risky energy mix that can serve as a foundation for future economic growth.

Decision by the PUC

On December 13, 2010 the PUC issued its written orders approving emissions reduction plans for Xcel Energy and Black Hills Corporation. In its orders, the PUC cited numerous positive benefits to the approved plans, including greater net economic development, air quality and public health improvements, and modernization of the state's electric system. "The state of Colorado and its electric consumers are much better off because of our actions in approving these plans," PUC Chairman Ron Binz said. "With these decisions, we have taken bold steps to reduce air pollution from power plants in a way that will be less expensive to consumers than any other course. This is vastly preferable to waiting for the Environmental Protection Agency to impose a plan for cleaning up power plant emissions." The PUC approved a plan for Xcel Energy to retire 550 megawatts of coal generation by closing three units at its Cherokee plant in Denver, one unit at the Arapahoe plant in Denver, and the Valmont plant in Boulder by the end of 2017. A new natural-gas fired unit will be built at the Cherokee site to replace the retired plants. The PUC also approved converting another coal-fired unit at Arapahoe to natural gas generation, and a fourth unit at Cherokee to natural gas. The PUC will explore other possible options for Cherokee 4 in Xcel Energy's next electric resource plan, which will be filed in 2011.

The PUC also approved the installation of additional emission control technology at Xcel Energy's Pawnee and Hayden power plants. The $1.4 billion plan is expected to add about 2.5 percent to electric rates by 2020. "We're confident that the 2.5 percent impact of this plan would be higher if we wait for the EPA to impose an emissions reduction plan," Binz said. Although there was contradictory evidence on the impact of the proposed plan on the coal mining industry, the Commission directed its staff to work with other local and state agencies to develop a contingency proposal for funding the retraining of coal mine workers if the emissions reduction plan results in layoffs in the mining industry. For Black Hills, the PUC approved retiring the company's two coal generation units in Canon City and replacing them with a new gas-fired units in Pueblo. Black Hills customers are expected to see an increase of about 5 percent in rates once the plan is fully implemented.

Conclusion

The combination of HB10-1001 and HB10-1365 represents major positive electric sector policy shifts in Colorado. The implications for economic, environmental, and energy technology benefits to the state are self-evident. Colorado's 30 percent RES is the most proactive in the interior West and is is the second strongest in the country. The economic opportunities and energy savings resulting from HB10-1001 will help the state achieve a variety of important objectives. The retirement of 900 MW of coal-fired generation and replacement by natural gas in Colorado is being watched by utility sector observers across the country. The implications for utility-scale renewable energy development and the need for expanding the high-voltage transmission infrastructure is directly associated with the HB10-1001 RES and, to a much lesser extent, with HB10-1365 Clean Energy-Clean Jobs Act.

5. Colorado's Transmission Infrastructure

REDI Review

Colorado transmission policy presents a series of dilemmas. Unless adequate transmission is available, a new utility-scale renewable energy project is unlikely. Without greater certainty that a new renewable energy project will be developed, new transmission may not be planned, or may not be approved.

The legislature passed SB07-100 to promote development of "clean, affordable, reliable electricity" by encouraging electric utilities to "promptly and efficiently improve" the transmission infrastructure in Colorado. The act requires IOUs to identify beneficial Energy Resource Zones and submit plans and applications to build transmission from these zones to connect to the existing transmission system. Independent transmission companies and utilities that own transmission assets that are not rate jurisdictional to the PUC (i.e., Tri-State and municipal utilities) are excluded from SB07-100.

Overview

Colorado's utilities are working to develop new transmission to meet legislative, regulatory, and reliability requirements. PSCo and Tri-State, the largest transmission owners, have dedicated personnel who are focusing a considerable amount of time and effort on transmission issues. Western Area Power Administration has a major presence in Colorado, but is not building a lot of transmission in Colorado, and is not subject to state regulation. Several other Colorado utilities own high-voltage transmission systems, albeit much smaller in scale than PSCo's and Tri-State's. These transmission-owning companies include Colorado Springs Utilities, BHE, Platte River Power Authority, and the Arkansas River Power Authority.

Public Service Company of Colorado

PSCo is the largest transmission owner and operator in Colorado. An in-depth review of the many details PSCo is pursuing regarding transmission is available at the company's website produced, in part, to comply with its FERC Order 890 requirements.[83] The company's SB07-100 website—SB100transmission—is quite informative.

PSCo's Existing Transmission Plans

Operating 17,335 miles of transmission lines throughout its eight-state service territory, Xcel Energy develops a ten-year planning and a 20-year visioning document[84] for transmission in each of its operating systems. PSCo publishes these planning and visioning documents annually. PSCo's transmission system includes:

- 4360 miles of transmission
- 223 substations served
- Operating company peak load = 6510 MW(7/14/2010)
- Balancing area load =7704 MW (7/26/2010)
- Wind=1258 MW
- Solar=25 MW

PSCo's transmission assets are located entirely in Colorado and within the WECC. Its major utility interconnections include:

- Western Area Power Administration
- Tri-State Generation and Transmission Association
- Colorado Springs Utilities
- Platte River Power Authority
- Black Hills Energy – Colorado
- Public Service New Mexico
- Southwest Public Service
- Arkansas River Power Authority

Figure 46 is a transmission ownership map with overlays of the state's GDAs developed for the REDI report. Figure 47 provides greater details, including substations.

PSCo's transmission plan proposes many transmission projects over the next five years to reliably satisfy load growth and to accommodate new retail and wholesale customers. In addition to these proposed projects, PSCo's transmission planning analyses also covers state, regional, and federal initiatives and requirements.

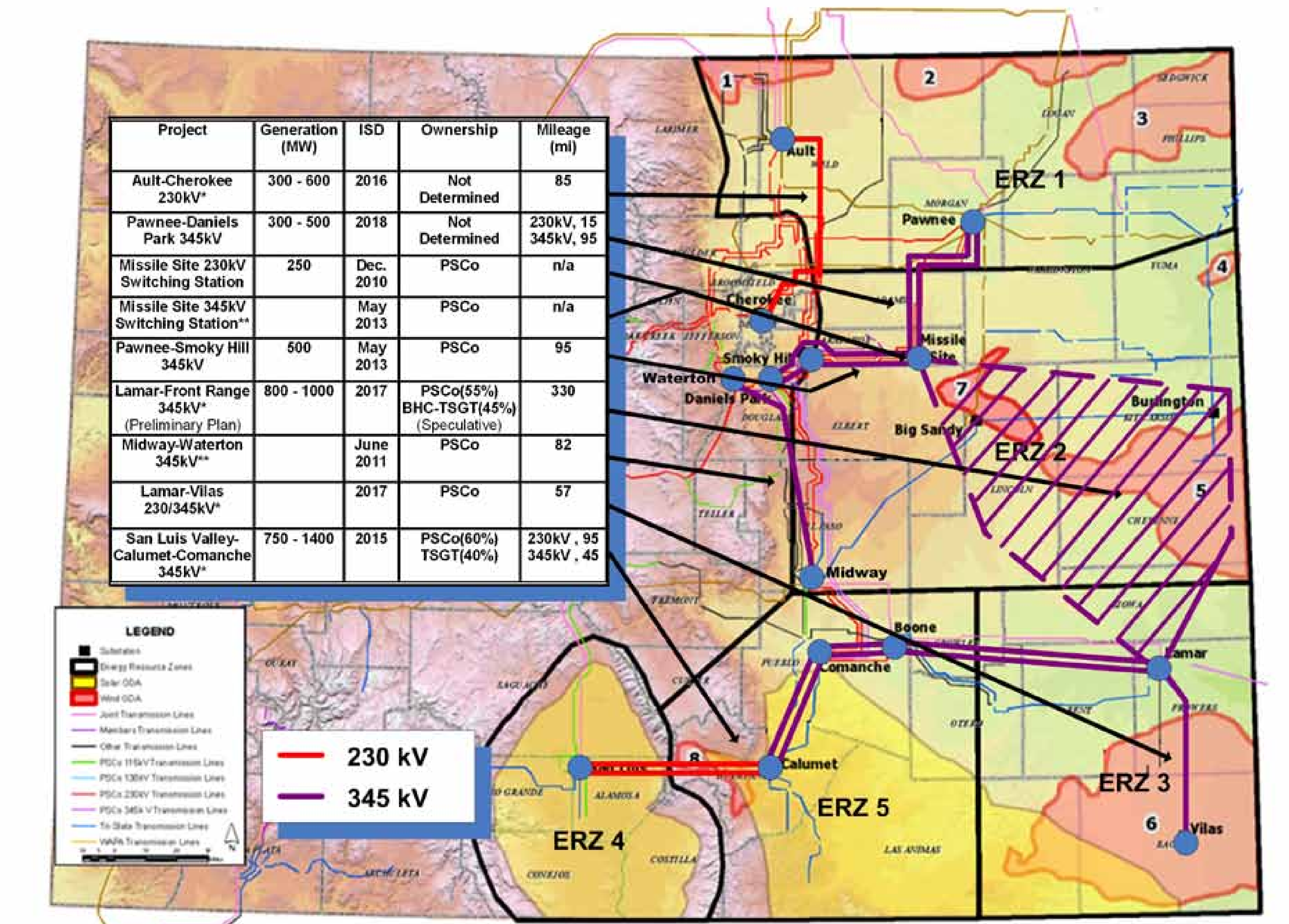
SB07-100

Under SB07-100, PSCo must meet the following requirements:

- Designate beneficial Energy Resource Zones (ERZs).
- Develop plans for construction or expansion of transmission facilities necessary to deliver electric power consistent with the timing of the development of ERZs located in or near such zones.
- Consider how transmission can be provided to encourage local ownership of renewable energy facilities.
- Submit proposed plans, designations, and applications for CPCNs to the PUC for simultaneous review.

PSCo's most recent transmission plan includes proposed SB-100 projects shown in Figures 45 and 48.

Public Service Company of Colorado
SB-100 Projects



Project	Generation (MW)	ISD	Ownership	Mileage (mi)
Ault-Cherokee 230kV*	300 - 600	2016	Not Determined	85
Pawnee-Daniels Park 345kV	300 - 500	2018	Not Determined	230kV, 15 345kV, 95
Missile Site 230kV Switching Station	250	Dec. 2010	PSCo	n/a
Missile Site 345kV Switching Station**		May 2013	PSCo	n/a
Pawnee-Smoky Hill 345kV	500	May 2013	PSCo	95
Lamar-Front Range 345kV* (Preliminary Plan)	800 - 1000	2017	PSCo(55%) BHC-TSGT(45%) (Speculative)	330
Midway-Waterton 345kV**		June 2011	PSCo	82
Lamar-Vilas 230/345kV*		2017	PSCo	57
San Luis Valley-Calumet-Comanche 345kV*	750 - 1400	2015	PSCo(60%) TSGT(40%)	230kV , 95 345kV , 45

*Indicates Actual Routing Has Not Been Determined
**Currently Under Construction

Figure 45A: PSCo's SB-100 Transmission Plan
Source: Public Service Company of Colorado

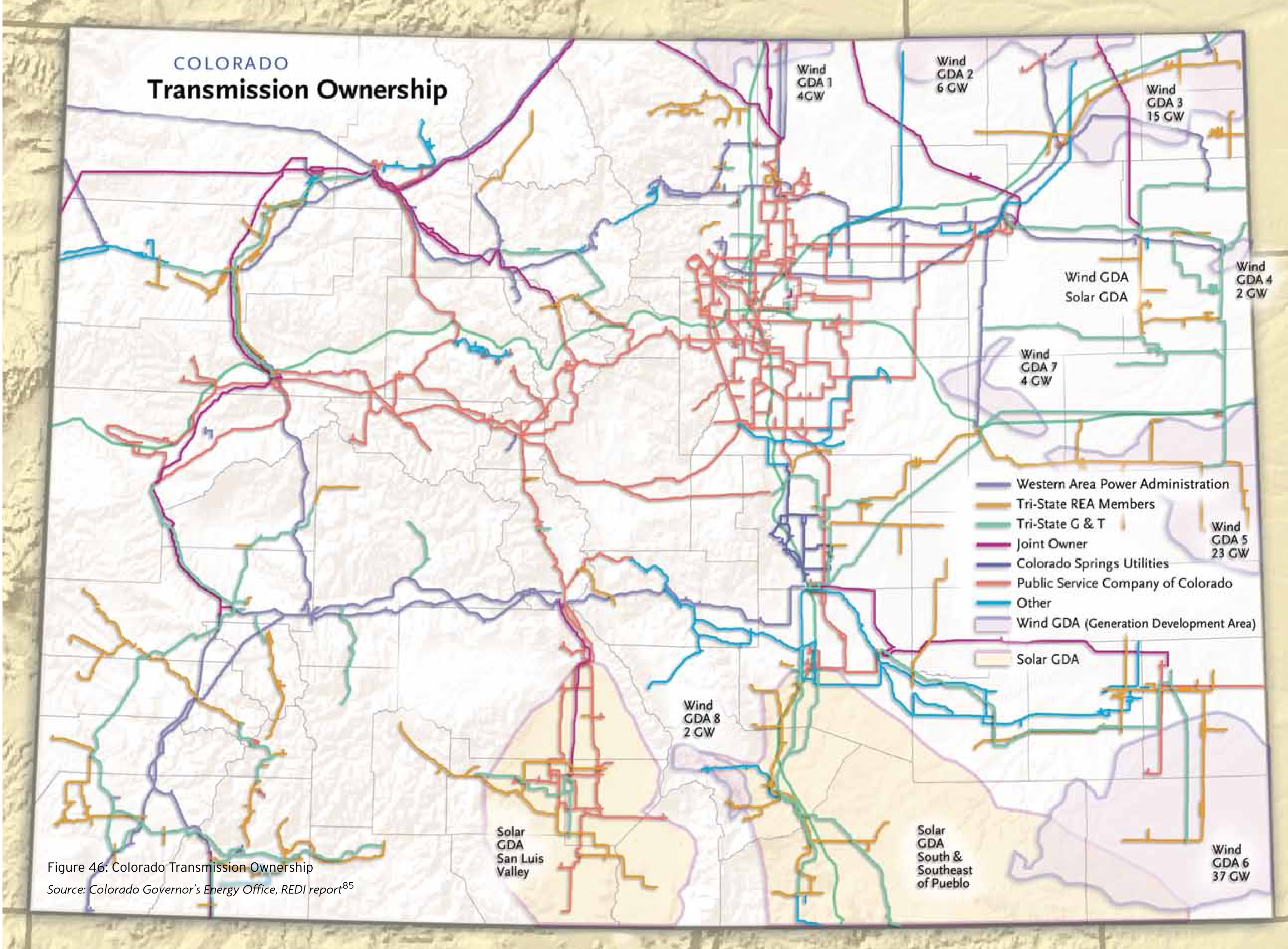


Figure 46: Colorado Transmission Ownership

Source: Colorado Governor's Energy Office, REDI report[85]

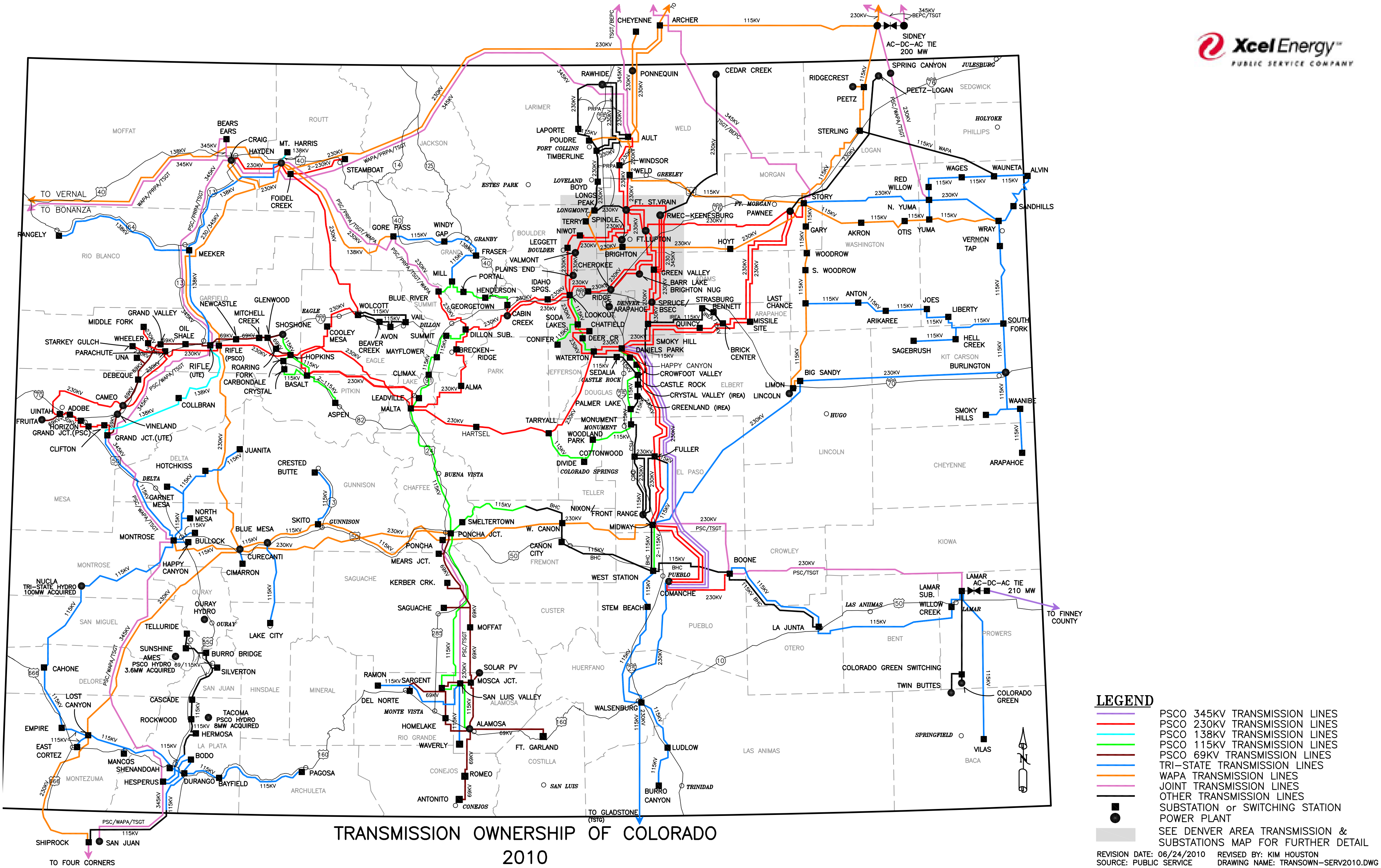


Figure 47: Transmission Ownership of Colorado

Source: Xcel Energy

Item	Project	Generation (MW)	In Service Date*	Project Status
1.	Missile Site 230kV Switching Station	250	Nov. 2010	Project Initiated, no CPCN necessary
2.	Midway-Waterton 345kV Transmission Project		June 2011	Modification of CPCN filed on April 20, 2009, and approved May 2009
3.	Pawnee-Smoky Hill 345kV Transmission project	500	Jan 2013	CPCN approved by the CPUC on Feb. 27, 2009
4.	San Luis Valley-Calumet-Comanche 345kV Transmission Project	750 - 1400	-	Joint CPCN filing May 14, 2009 by PSCo and TSG&T
5.	Missile Site 345kV Switching Station		Jan 2013	Supplemental filing in September 2009
6.	Lamar-Front Range 345kV •Lamar-Comanche •Lamar-Missile Site	800 - 1000	2017	CPCN set to be filed in 2011*
7.	Lamar-Vilas 230/345kV transmission Project		2017	CPCN set to be filed in 2011*
8.	Ault-Cherokee 230kV Transmission Project	300 - 600	-	TBD*
9.	Pawnee-Daniels Park 345kV Transmission Project	300 - 500	-	TBD*

Figure 48: Proposed SB-100 Projects

Source: PSCo[87]

Tri-State Generation and Transmission Association, Inc.

Tri-State[86] is a wholesale electric power supplier owned by the 44 electric cooperatives it serves (18 in Colorado, 12 in New Mexico, eight in Wyoming, and six in western Nebraska) identified in the service territory map in Figure 49. Based in Westminster, Tri-State is Colorado's second-largest electric utility. The Colorado members are distribution-only rural electric association cooperatives. Tri-State is both a transmission provider and a customer of transmission and control area services from other utilities, including Platte River Power Authority, PacifiCorp, PSCo, PNM, Western Area Power Administration, the City of Farmington, Nebraska Public Power District (NPPD), and others. Tri-State owns, operates, and maintains a 5,267-mile high-voltage transmission network and 135 substations and switching stations throughout the four states in which it operates.

The following information was obtained from Tri-State's website:

"Tri-State is an active member of the Colorado Coordinated Planning Group, the Southwest Area Transmission Planning Group, and WestConnect. These organizations provide the framework for regional and subregional planning among the region's transmission providers. Tri-State holds open public transmission planning meetings each year to allow customers, interconnected neighbors, regulatory and state bodies, and other stakeholders to participate in the development of its transmission plan. These planning processes are linked to, and part of, Tri-State's electric resource plan (ERP). In developing its 2010 ERP, Tri-State evaluated 24 scenarios that play out Tri-State's planning assumptions, input from public participants, and boundary cases designed to show potential future operating conditions. The scenarios also reflect different levels and mixes of load growth, renewable resources, emissions costs, capital costs, and demand-side management measures, and other variables.[88]

In addition to its ERP, Tri-State produces a ten-year transmission capital construction plan. This plan, divided into project categories, includes 49 continuing projects, 20 new projects, and 70 planned projects (other categories include replacements and efficiency projects and 100 percent reimbursed projects).[89]

Throughout its transmission network, Tri-State has worked with its members and other regional utilities on several expansion projects, primarily focused on addressing continued load growth, reliability issues, and interconnection requests. In 2009, Tri-State continued to move forward on a number of projects, including a partnership with PSCo to develop needed power lines from Colorado's San Luis Valley to Pueblo, and addition of new lines from New Mexico into southwest Colorado. As part of its long-range plans, Tri-State is examining several other large projects, including major transmission lines and infrastructure in eastern and southern Colorado that support reliability, growth, and the interconnection of new generation resources. An overview of under-construction, planned or proposed transmission projects that are in, or pass through Colorado, are discussed below.

- Tri-State's latest transmission project is the 115 kV Nucla-Sunshine

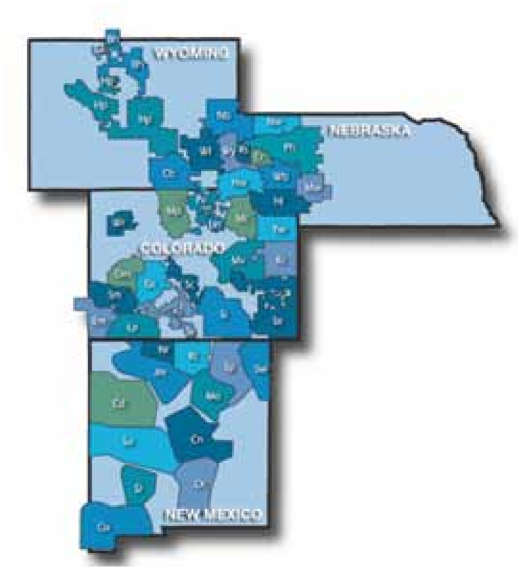


Figure 49: Tri-State Membership
Source: Tri-State Generation and Transmission[90]

line in southwestern Colorado. The new 51-mile line is scheduled to be completed and energized in 2012. The transmission line is needed to replace an aging 69-kV line between Nucla and Telluride that is owned by Tri-State member cooperative San Miguel Power Association. Tri-State filed for and obtained a CPCN from the PUC for the line in 2001. Tri-State returned to the PUC in 2003, seeking review of conditions imposed on construction of the line by the Board of County Commissioners of San Miguel County. In 2004, the Commission entered an order on Tri-State's application. The order was appealed to the Colorado Supreme Court, which rendered a decision on the appeal in 2007. Construction began on the line in June 2010.

- Tri-State is building a new eight-mile, 115-kV transmission line to improve reliable electric service to the member-consumers of Poudre Valley REA.
- Tri-State, La Plata Electric Association, and other regional utilities have faced a strain on existing infrastructure in response to recent load growth and, despite recent system improvements, face the need to import more power into the region to supply growing communities. The proposed San Juan Basin Energy Connect Project would involve construction of a 230-kV transmission line by Tri-State from the Farmington, New Mexico, area to Ignacio, Colorado.
- San Luis Valley-Calumet-Comanche Project. This is a joint project with PSCo for construction of a double circuit 230-kV line from the San Luis Valley to the Comanche plant in Pueblo. The companies filed simultaneous applications for CPCNs with the PUC to construct the line in May 2009. The applications have met substantial resistance, primarily from a wealthy landowner who owns property in the area where the utilities propose to construct the line. The Administrative Law Judge (ALJ) entered a Recommended Decision in November 2010. The ALJ granted the certificates but placed a condition on the PSCo certificate requiring it to refund one-half of the funds collected from ratepayers, including any authorized return, for construction of the line if a total of 700 MW of generation is not interconnected with the line within 10 years of its in-service date. At the time of publication of this report, the PUC was reviewing the ALJ's decision; a decision is anticipated in January 2011.
- Lamar-Front Range Project. Tri-State, PSCo, and BHE have agreed to share the cost of performing planning studies for transmission facilities in eastern and southeastern Colorado.
- Tri-State is a participant in the HPX transmission initiative.

On Sept. 20, 2010, Tri-State's board of directors approved the 2011 capital construction budget, which includes $299 million for projects, including $160 million (54 percent) in transmission investments. Tri-State's ten-year capital outlook for transmission estimates $1.2 billion in investments to ensure the association can meet member needs across its four-state, 200,000-square-mile service territory.

'We continue to place a significant focus on transmission infrastructure, as it is vital to ensuring rural communities' access to reliable and affordable electricity' said Tri-State executive vice president and general manager Ken Anderson. 'A stronger transmission network will also better connect future renewable and conventional generating resources.'[91]

Planning for new long-term transmission infrastructure in Colorado has been under way for several years. In 2005, Tri-State began development of the Eastern Plains Transmission Project (EPTP), a high-voltage transmission system across eastern and southern Colorado that would reliably serve the association's member systems, relieve existing transmission constraints, and support additional interconnections, including those from renewable energy developers. The Colorado Long-Range Planning Group—an open process made up of utilities and other interested stakeholders—identified major portions of EPTP as critical to integrating new resources, including renewables, into the grid and delivering them to load centers.

In 2005, Tri-State began planning the San Luis Valley Electrical System Improvement Project (SLVESIP), which includes a transmission line from the San Luis Valley to Walsenburg, with another segment planned to Pueblo County. Tri-State proposed the project to better serve two electric cooperatives in the region—San Luis Valley Rural Electric Cooperative, based in Monte Vista, and San Isabel Electric Association, based in Pueblo West. This line also will provide for significant export of solar resources should they be developed in the valley.

In October 2008, Tri-State and PSCo announced they will jointly pursue transmission projects in southern Colorado under a memorandum of understanding. The projects identified in the agreement, including portions of the EPTP and SLVESIP, would strengthen southern Colorado's power delivery infrastructure, serve growing electricity needs, and interconnect new energy resources, including renewables.

By the end of 2011, at a cost to its members of more than $300 million, Tri-State will have completed more than 40 ongoing projects in Colorado to maintain and upgrade the reliability of its transmission system. These projects include the joint Western Cheyenne-Ault project, which increased TOT3 capability by 75 MW; the Story-Erie rebuild and upgrade for load-serving capability in northeastern Colorado; and the Big Sandy-Lincoln-Midway 230-kV upgrade to help deliver energy resources to the Front Range. Other expansion includes the Lamar-Burlington, Energy Center-Burlington-Big Sandy-Road 125 Corner Point, and the Lamar-Comanche projects at 345-kV or 500-kV, and the San Juan Basin 230-kV transmission line from northwest New Mexico to southwest Colorado. These projects demonstrate Tri-State's commitment to transmission development that will significantly benefit Colorado and the region.

Western Resource Advocates Positions Regarding Tri-State's Electric Resource Plan

Founded in 1989, WRA is a nonprofit environmental law and policy organization. With offices in seven states (Arizona, Colorado Idaho, Nevada, New Mexico, Utah, and Wyoming), WRA has developed strategic programs in three areas: water, energy, and lands.

Tri-State and WRA reached an accord, approved by the PUC, in December 2009, regarding Tri-State's electric resource planning process. Under the new planning process, Tri-State will develop its resource plan in two steps. In the first step, the public will be able to provide input to Tri-State during development of the resource plan. In step two, Tri-State will file its plan with the PUC, address any questions the commission may have, and hear the commission's views of the plan and the public participation process. WRA's preliminary position on Tri-State's 2010 draft electric resource plan is that it is a significant improvement over the 2007 plan. The 2007 plan noted the need for at least two large coal units, but underemphasized the role DSM and renewable resources might play in satisfying load. The new plan predicts no new, large, supply-side resources until 2019, attributable to a sizable reduction in anticipated load growth due to the economic downturn. It also includes initiatives that will help WRA understand how to integrate renewable resources into the system and leverage the value of DSM.

Western Area Power Administration Transmission

The following is from Western Area Power Administration's[92] website: "Western markets and delivers reliable, cost-based hydroelectric power and related services within a 15-state region of the central and western United States. See Figure 50. Western is one of four power marketing administrations within the DOE that market and transmit electricity from multiuse water projects.

In June 2009, Western published its revised strategic plan, which includes the following transmission construction goal: Ensure Western has the capability to construct critical reliability transmission projects that are paid for by beneficiaries.

Strategies to reach this goal include the following.

- Evaluate resources and capabilities to support construction projects based on project-specific needs; continue to prioritize construction and rehabilitation projects each year.
- Improve the accuracy of future workload projections associated with likely transmission reliability and expansion needs.

Figure 50: Western Area Power Administration
Source: Western Area Power Administration[93]

- Use a business-case analysis to evaluate the benefits, costs, and risks of participation in transmission projects against Western-wide criteria.
- Identify and pursue one or more transmission projects to be funded and paid for by beneficiaries under the authority granted to Western in the Energy Policy Act of 2005.
- Identify and pursue one or more transmission construction projects under the authority granted to Western in the American Recovery and Reinvestment Act of 2009 that would facilitate delivery of renewable resources to market.[94]

Western owns and operates more than 17,000 circuit miles of transmission lines (Figure 51), 258 substations, and other electric power facilities in its 15-state service territory. To ensure reliable electric service, this system must be maintained and periodically upgraded. In addition, facilities may need to be added or expanded to meet new demands. Western will participate, either as the lead agency or as a partner, in the following proposed transmission construction projects that are relevant to Colorado:

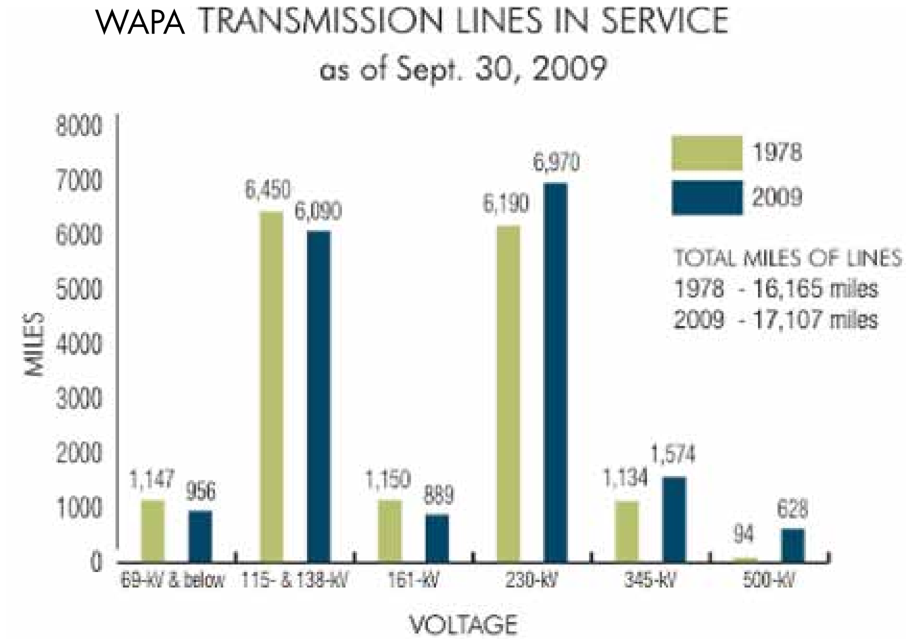


Figure 51: Transmission Lines in Service as of September 30, 2009
Source: Western Area Power Administration[95]

- Beaver Creek-Hoyt-Erie Transmission Line Rebuild, Colorado, DOE/EA-1508
- Granby Pumping Plant-Windy Gap Transmission Line Rebuild Project
- Cheyenne-Miracle Mile and Ault-Cheyenne Transmission Line Rebuild Project, Colorado and Wyoming, DOE/EA-1456 "

Western created its Transmission Infrastructure Program (TIP) to respond to opportunities that became available through Section 402 of the American Recovery and Reinvestment Act (ARRA). According to Western's website: "ARRA includes measures to modernize our nation's infrastructure and enhance energy independence, which is where Western comes in. The Recovery Act, Section 402, provides Western with new authority to construct transmission lines to help deliver renewable resources to market and, importantly, provides a source of funds for this activity. The TIP goals are to: construct and/or upgrade transmission lines to help deliver renewable resources to market; select, study and/or build projects under this authority that are in the public interest; solicit public input in identifying potential projects; ensure projects do not adversely impact system reliability or operations, or other statutory obligations; ensure projects are economically feasible and are adequate to repay project costs; and leverage borrowing authority by partnering with others.

The TIP established ten principles to provide guidance in implementing the authority to borrow up to $3.25 billion from the U.S. Treasury to fund partnerships to develop transmission infrastructure that delivers renewable energy to market across the West (see figure 52). For a variety of reasons, at the time of publication, the principles and conditions in the market are such that only a fraction of Western's loan guarantee money has been placed in to service. Western's first project is now in progress with help from the TIP process—the Montana-Alberta Tie Limited Project (MATL). Western is providing the financing arrangement between the Canadian project developers and Western. The $161 million comes from Western's borrowing authority under the Recovery Act; the total project costs are estimated to be $213 million."

As of August 2010, Western listed these proposed projects as "under discussion": The Sonoran-Mojave Renewable Transmission Project, the Wyoming Wind Transmission Project, the Wyoming Wind Collector System, the Electrical District 5 to Palo Verde (SPPR), the SunZia Southwest Transmission Project, the NV Energy Transmission Line Project, the Mead-Peacock-Liberty 345-kV Upgrade (Mohave Sun), and the TransWest Express, described below.

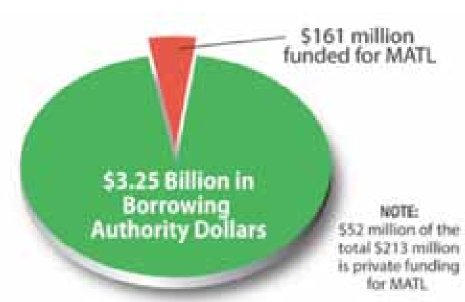


Figure 52: Allocation of Western's Load Allocation Funding

Source: Western Area Power Administration[96]

Other Stakeholders in Colorado's Transmission System

Wyoming-Colorado Intertie Project

The Wyoming-Colorado Intertie Project (WCI), is a proposed new 345-kV transmission project that is envisioned to stretch approximately 180 miles between the Laramie River Station substation located near Wheatland, Wyoming, and the Pawnee substation located near Brush, Colorado (Figure 53).

Expansion of the constrained TOT3 interface located along the Wyoming-Colorado border was identified and recommended for development by a consensus of regional stakeholders in the 2004 Rocky Mountain Area Transmission Study (RMATS). In 2005, the Wyoming Infrastructure Authority (WIA), Trans-Elect Development Company (Trans-Elect), and Western formed a partnership to examine expansion of TOT3. After gauging interest from stakeholders and conducting a series of studies, the project partners identified the WCI as a TOT3 solution and proceeded with development. In 2009, LS Power acquired development rights to the WCI and is continuing development in partnership with the WIA, with technical assistance from Western.

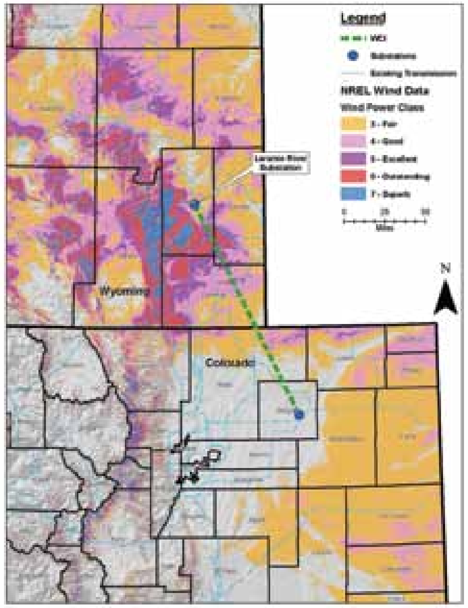


Figure 53: Proposed Wyoming-Colorado Intertie Project

Source: Wyoming-Colorado Intertie[97]

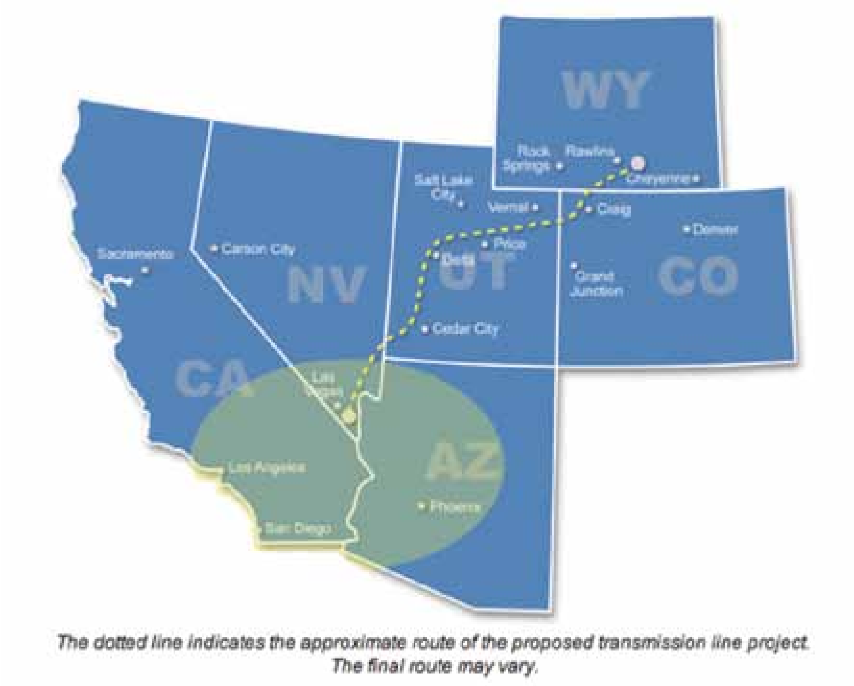


Figure 54: TransWest Express Transmission Project

Source: TransWest Express[98]

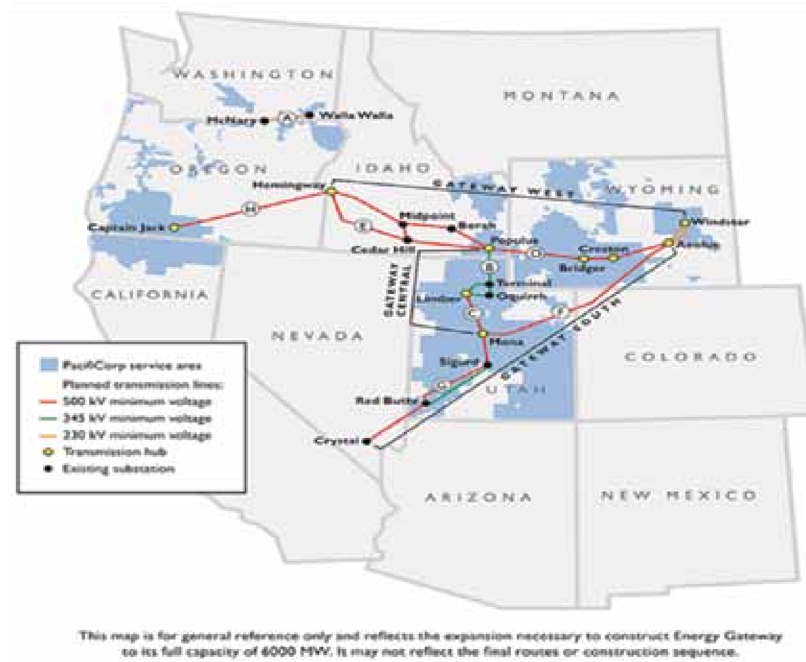


Figure 55: Energy Gateway Transmission Expansion Project

Source: PacifiCorp[100]

TransWest Express Transmission Project

TransWest Express LLC[99] is a wholly owned affiliate of The Anschutz Corporation, a privately held company based in Denver. The TransWest Express (TWE) transmission project is a proposed extra-high-voltage direct-current electric transmission system. The general route will begin in south-central Wyoming, extend through northwestern Colorado and central Utah, turn southwest into southern Nevada, and end near Las Vegas (Figure 54). The TWE Project has been under conceptual development since 2005. Construction on the transmission line is anticipated to begin in 2013. Project statistics include:

- 3,000-MW capacity
- 600-kV high-voltage direct current (HVDC)
- 725-mile proposed route
- Three-year construction, creating 1,000-plus jobs each year
- 2015 in-service date
- $3 billion cost

Energy Gateway Transmission Expansion Project

PacifiCorp's Energy Gateway Transmission Expansion Project[101] involves building a high-voltage transmission line project across southern Wyoming, potentially crossing northwest Colorado, through Utah to a point north of Las Vegas, Nevada (Figure 55). This approximately 800-mile-long line segment, Gateway South, will enhance electric system reliability throughout the region. In addition, the project will enable delivery of existing and new generating resources, including wind, to more customers. The line is estimated to be placed in service by 2017 or 2019.

Transmission Investments Are Needed

As shown in Figure 56, annual transmission expenditures in the United States have increased from a low of around $2 billion in the 1990s to current spending levels that are approaching $9 billion. This transmission build-out has been driven by three primary factors: 1) bringing new renewable energy to the load centers, 2) improving reliability and overall grid integrity; and 3) removing congestion bottlenecks to allow electric customers greater access to lower cost energy available in other regions.

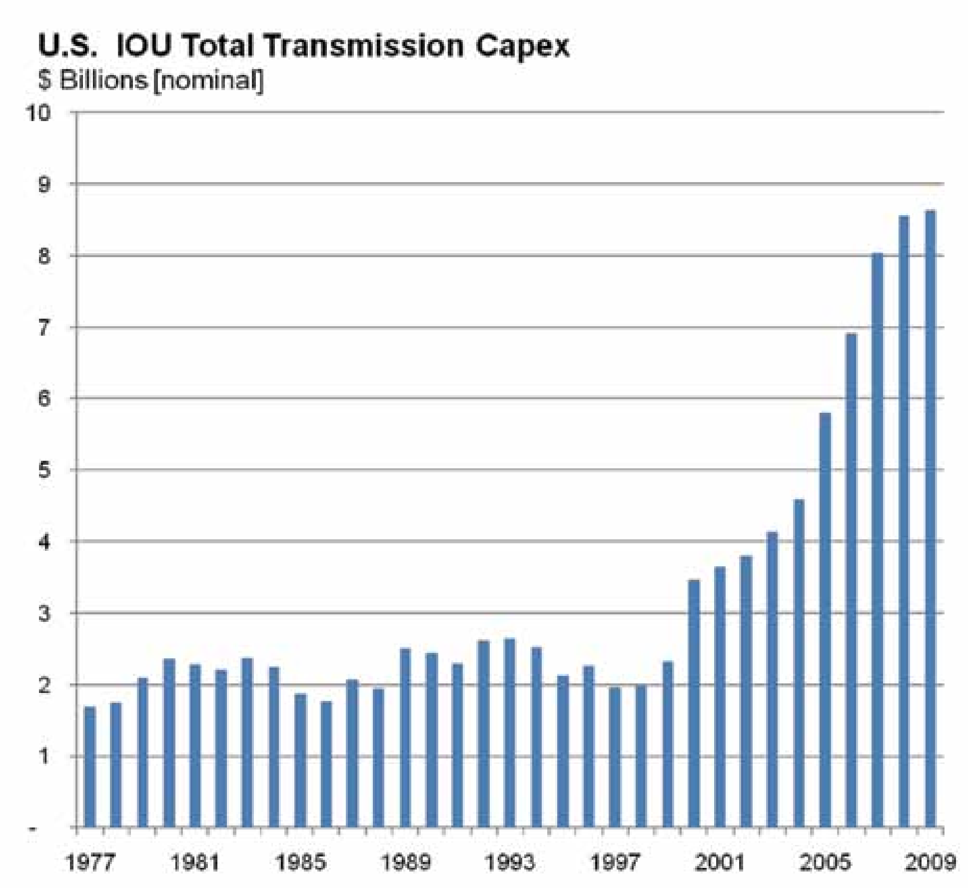


Figure 56: U.S. IOU Total Transmission CapEx

Source: North American Electric Reliability Corporation

In a report to the EEI, The Brattle Group has estimated that: "$50 to $100 billion in transmission investment will be needed in order to integrate renewable power onto the existing electricity grid. Without a multi-billion investment on the order of $50 [billion] to $100 billion, our nation's transmission capabilities will be insufficient to allow for the integration of enough renewable power sources into the high voltage grid to meet the RPS requirements." Their November 2009 report, *Transforming America's Power Industry: The Investment Challenge 2010-2030,* the group states that "investment in the electricity system on the order of at least $1.5 trillion will be required from 2010 to 2030. This includes generation at $505 billion, assuming no changes in carbon policy or long-term price effects; transmission at $298 billion; distribution at $582 billion, and advanced metering infrastructure and energy efficiency/ demand response at $85 billion."

Conclusion

Colorado transmission-owning utilities, the PUC, and others are investing extensive time and internal resources to develop a transmission system that conforms to PUC and legislative requirements that meets the needs of their customers.

A series of studies over the past decade have concluded that Colorado's transmission infrastructure is congested and under-sized in voltage and capability. Policy-makers and utilities are responding with heightened attention to planning and permitting challenges that need resolution to deliver large blocks of renewable energy to load centers. Concrete and near-term actions are warranted to resolve these issues. The state needs a continued flow of information and solid assurance that Colorado's utilities and regulators will strategically plan, permit, and build transmission infrastructure consistent with the need to deliver clean, reliable power to a growing population in a water-scarce state.

6. The Growing Importance of Natural Gas

REDI Review

To reach the CO_2 reduction goals outlined in Colorado's Climate Action Plan will require increased demand-side measures, utility-scale renewable energy, new high-voltage transmission, more natural gas generation, and initiatives that address CO_2 emissions from the state's oldest and least-efficient fossil plants. Estimates of required generation are based on assumptions of the growth in electric demand. The REDI's modeling results indicate that meeting the reduction goals will involve a substantial increase in the use of renewable power and natural gas generation.

On many occasions, Governor Ritter has noted that he considers natural gas to be a "mission-critical" fuel and an essential and permanent part of the New Energy Economy. Connecting the renewable energy potential in the state's GDA s to markets, in combination with aggressive demand-side measure activities and more natural gas-fired generation, can help meet the CO_2 reduction goals.

Overview

Natural gas has emerged as the critical fuel of the future for several energy sectors, especially electric power generation. Gas is attractive to electric power system planners for several reasons.

- Gas generation plants are faster to permit and build than several other options (most notably coal, nuclear, and large hydroelectric).
- The capital commitment for purchasing gas-generating facilities is smaller than that required for coal, nuclear, and large hydroelectric generation.
- Gas generation plants have flexible operating parameters, allowing them to ramp up and down quickly in response to variable generation resources such as wind and solar.
- Gas generation plants emit approximately 60 percent less CO_2 per unit of electricity produced than a typical coal plant and have a variety of other favorable environmental and siting attributes.

Natural gas generation also brings with it factors that concern utility planners.

- The price of natural gas historically has been volatile and, during the last decade, has swung many times between \$4 and \$12 per million metric British thermal units (MMBtus).
- The difficulties of contracting for long-term natural gas supplies make any power portfolio more risky for each incremental addition of natural gas as measured by traditional resource planning metrics (e.g., the standard deviation of portfolio costs).
- In the absence of any agreed-upon price for CO_2 emissions, natural gas has a higher variable fuel cost than coal and nuclear, yet this drawback is counter-balanced by its lower capital construction and maintenance costs.
- Although today's gas-fired technologygeneration emits less CO_2 than coal, a considerable amount of CO_2 still is emitted.

Natural gas generation is likely to be an ever-growing fraction of the electricity sector for at least the next decade and likely much longer. The significance of natural gas is illustrated in Figures 57 and 58. Natural gas is a key component not only in the electricity sector (about 18 percent of total installed capacity), but also in the residential, commercial, and

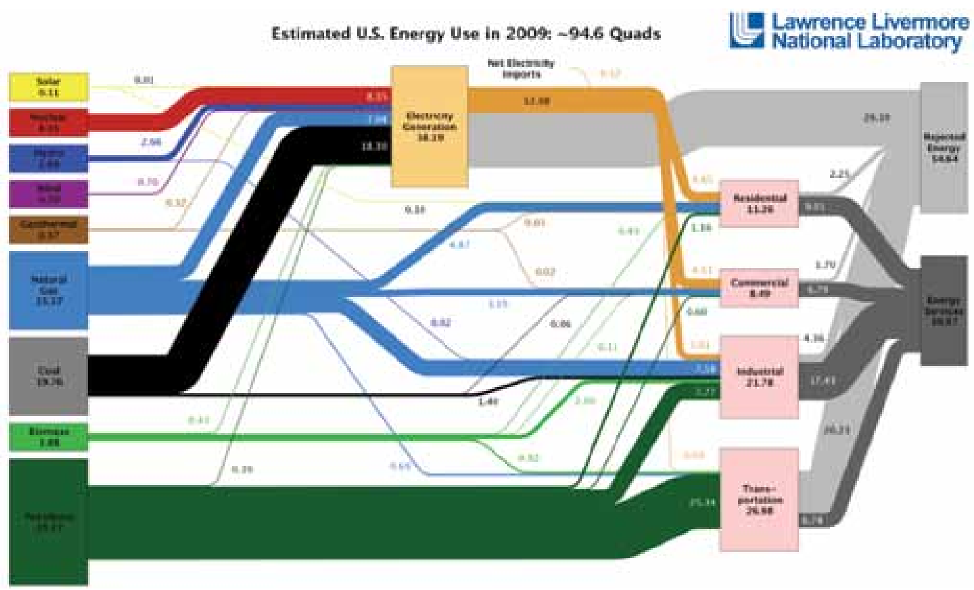


Figure 57: Estimated U.S. Energy Use in 2009, Approximately 94.6 Quads
Source: Lawrence Livermore National Laboratory[102]

Natural gas generation will increase by more than 30 percent during the next ten years, while coal-fired generation, which currently provides about half of the power in the United States, will grow by only 6 percent.

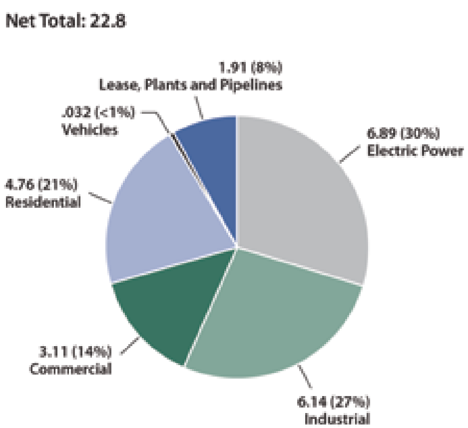


Figure 58: The Distribution of Natural Gas

Source: EIA and MIT: The Future of Natural Gas: An Interdisciplinary Study, 2010

industrial sectors. It is also used to make fertilizers and a host of other products.

The North American Electric Reliability Corporation forecasts that natural gas generation will increase by more than 30 percent during the next ten years, while coal-fired generation, which currently provides about half of the power in the United States, will grow by only 6 percent. Despite the optimism surrounding natural gas, many utility executives may still be cautious about using gas for a larger fraction of the electric power mix due to its history of price volatility. Recent optimistic supply forecasts and the prospect of low and stable prices, however, have caused an increasing number of utility planners to reconsider natural gas for baseload power generation.[103] See Figure 61.

Colorado's Natural Gas Industry

Colorado ranks sixth among all states in natural gas production (Figure 59). According to the Colorado Oil and Gas Association (COGA), approximately 10 percent of the nation's natural gas reserves and ten of the nation's 100 largest natural gas fields are located in the state (Figure 60).

COGA states that "Oil and gas drilling in Colorado provides an economic impact of $23 billion per year, contributing over $135 million in revenue to the state, including nearly 90 percent of state severance taxes, the industry employs more than 70,000 people. Colorado's Piceance Basin holds the second-largest proven natural gas reserve in the country, although this is not conventional gas, and much of it is not economically recoverable. Colorado is responsible for more than 25 percent of all coalbed methane produced in the United States, and it accounts for about 50 percent of the state's natural gas production. Thirty-six of Colorado's 64 counties

Top Natural Gas Producing States, 2007

Rank	State	Marketed Production Million Cubic Feet
1	Texas	6,091,724
2	Wyoming	1,923,224
3	Oklahoma	1,744,393
4	New Mexico	1,544,830
5	Louisiana	1,363,538
6	Colorado	1,242,571
7	Alaska	433,485
8	Utah	376,409
9	Kansas	365,877
10	California	307,160

Figure 59: Top Producing Natural Gas States in 2007

Source EIA www.eia.doe.gov[104]

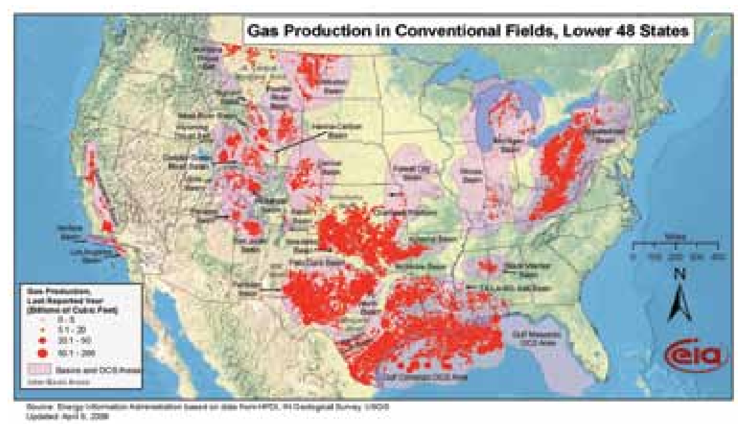


Figure 60: Gas Production in Conventional Fields, Lower 48 States

Source: Energy Information Administration[105]

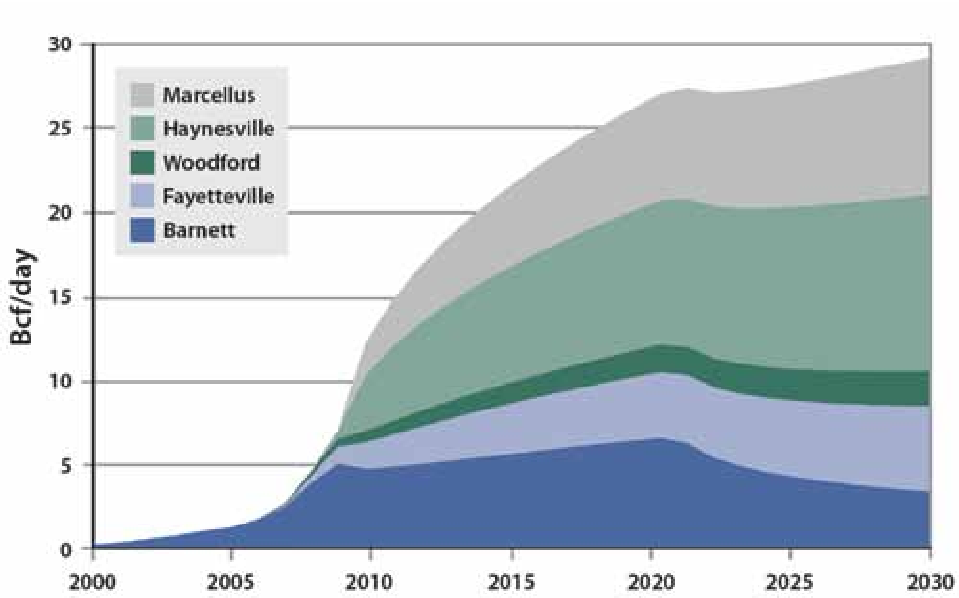


Figure 61: Potential Production Rate That Could Be Delivered by the Major U.S. Shale Plays Up to 2030
Source: MIT's report, The Future of Natural Gas: An Interdisciplinary Study, 2010

actively produce oil or natural gas. Three of every four homes in Colorado are heated with natural gas, compared to the national average of just over half of homes. Three-fifths of Colorado's natural gas is exported to meet demand in other states. With an estimated 21,850 billion cubic feet of dry natural gas, Colorado has 9.2 percent of the nation's supply, and 6.1 percent of liquid reserves."[106]

Both within and outside the state, electric utilities are reassessing their aging coal fleets, considering the potential of increased environmental regulation, and, with lower gas prices, moving toward greater reliance on renewable energy and gas-fired energy generation. Governor Ritter has made it clear on several occasions that natural gas is an important component of the New Energy Economy.

Colorado's natural gas infrastructure is extensive, as shown in figure 62. The extent of the existing infrastructure is significant because most of the expected natural gas repowering projects over the next decades are likely to occur near the Front Range areas where the existing population and electric load are the greatest. Strong natural gas supplies and pipelines are available on the Western Slope to help replace coal-fired generation when those units are retired. Figure 63 illustrates that Colorado is well-suited to support these future needs.

Natural Gas Supply and the Impact of Shale Gas

Proven reserves of natural gas in the United States have grown *substantially* during the past several years, largely due to the advent of the shale gas resource.

Shale gas is natural gas produced from shale deposits. Because gas-bearing shale typically is not permeable enough to allow significant fluid flow to a well bore, it only recently has been considered a commercially viable source of natural gas. Advances in hydraulic fracturing technology—"fracking"—have changed that. Hydraulic fracturing involves injecting fluids at high pressures to create fractures in the shale formations through which the gas can pass and be collected in commercial quantities (Figure 64). According to the American Petroleum Institute, up to 80 percent of natural gas wells drilled in the next decade will require hydraulic fracturing. It is projected that shale gas will constitute more than 20 percent of the total U.S. gas supply by 2020. This is due not only to significant advances in the use of horizontal drilling and well stimulation technologies, but also to the fact that these technologies have become more cost-effective.

Although hydraulic fracturing has been in development for several decades, a surge in momentum occurred during the last few years. Many believe this technology has the potential to be of significant benefit for the natural gas industry worldwide, and it has been key to the higher estimates of U.S. natural gas reserves.

According to the EIA, proven U.S. reserves rose from 164 trillion cubic feet (Tcf) in 1998 to more than 245 Tcf in 2008. Most industry experts suspect the growth has been even more significant. In an April 2010 speech, Energy Secretary Steven Chu said that "new natural-gas drilling technologies have definitely increased reserves by about 30 percent and probably doubled U.S. reserves."[107]

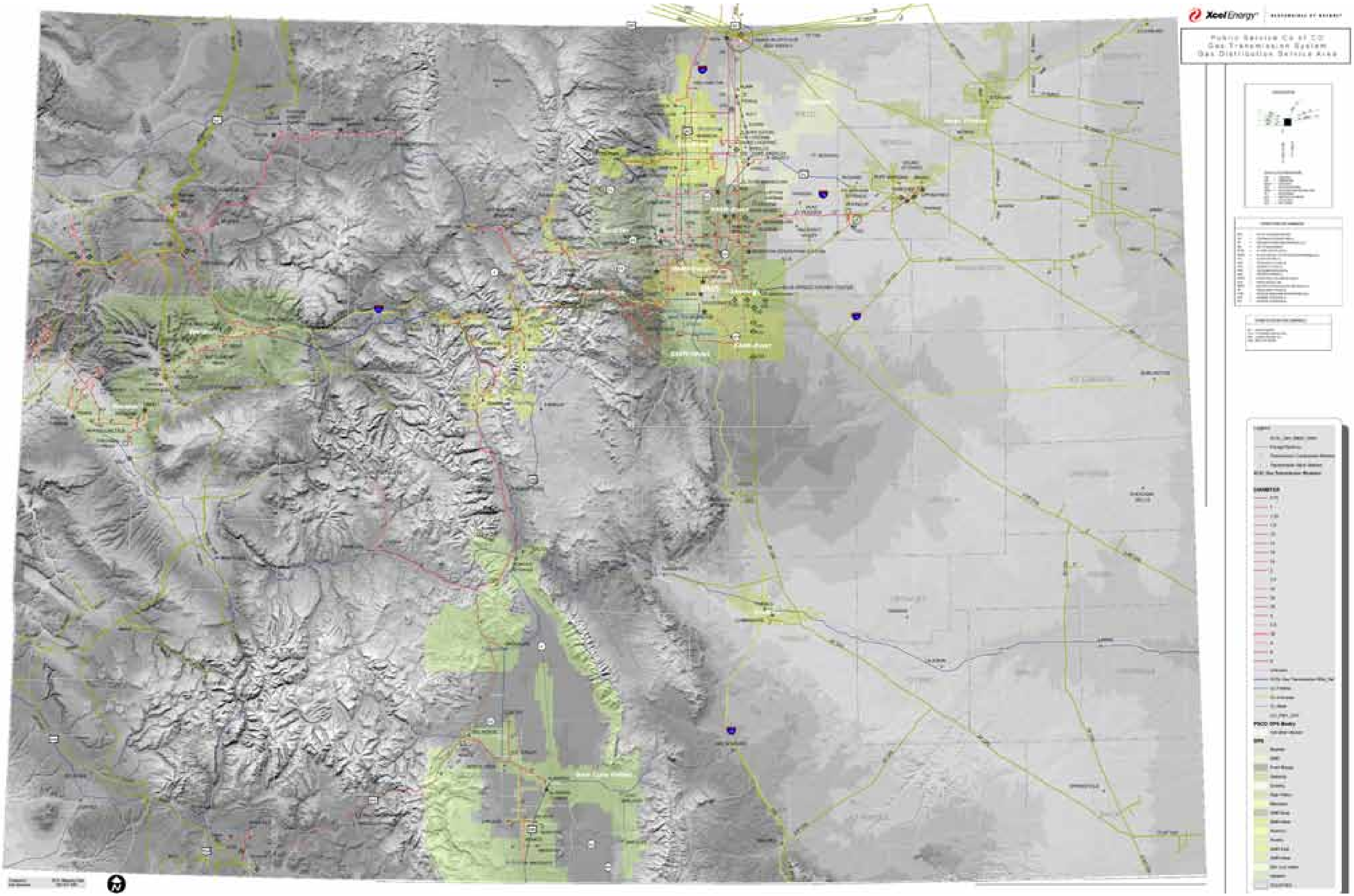


Figure 62: Colorado Natural Gas Infrastructure

Source: Xcel Energy[108]

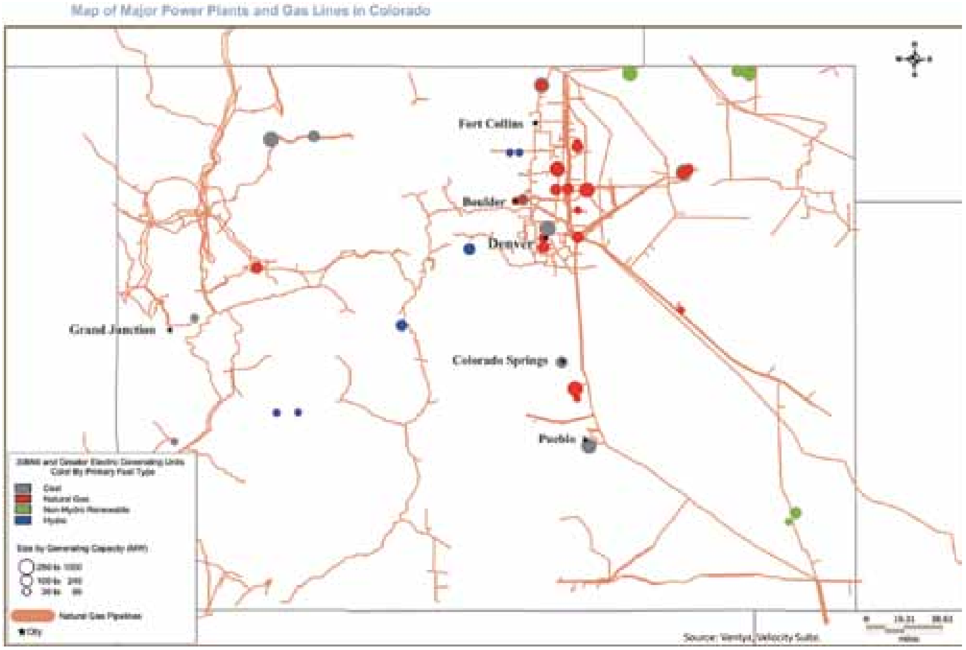


Figure 63: Map of Major Power Plants and Gas Lines in Colorado

Source: Ventyx, Velocity Suite and Colorado Governor's Energy Office

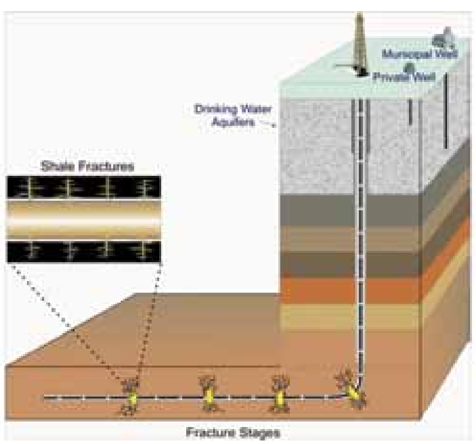


Figure 64: Hydraulic Fracturing

Source: Jack Towne for U.S. Congress[109]

The Colorado School of Mines Potential Gas Committee's June 2009 report estimated the technically recoverable natural gas resource base was 2,074 Tcf as of the end of 2008. The EIA's *Annual Energy Outlook 2010* includes estimates for total technically recoverable natural gas resources in the United States at an even higher level of 2,119 Tcf, including proved reserves, inferred reserves, and undiscovered technically recoverable resources. The *Annual Energy Outlook 2010* includes an estimate of 347 Tcf for unproved technically recoverable shale gas. With these new reserves, it is estimated that the amount of proven and potential gas supply in the United States can meet demand for the next 80 years or more.[110]

Environmental Effects of Hydraulic Fracturing

Shale gas development is not without its potential risks. Hydraulic fracturing uses a slurry fluid that is 99 percent water and sand. According to the Ground Water Protection Council, the remaining portion of the fluid is composed of an average of 14 chemicals that are used to condition the water. Concerns have been raised not only about the composition of these chemicals, but also about the numerous chemicals (more than 500) that are used across all hydraulic fracturing operations and their potential effects on drinking water. Concerns also have been raised regarding the lack of reporting and tracking of the chemicals used in specific drilling operations.

It is evident that there are pros and cons to hydraulic fracturing. Although the EPA has, to date, not found widespread adverse environmental impacts of hydraulic fracturing, in March 2010, the agency launched a study evaluating its potential effects on drinking water.

A COGA fact sheet lists several sources that suggest that environmental questions associated with fracking are negligible or nonexistent.[111] In contrast, the Natural Resources Defense Council[112] and other environmental organizations[113] have noted problems and expressed a variety of concerns. Of significance is a unanimous decision issued by the Wyoming Oil and Gas Conservation Commission in June 2010 that applies new requirements to better protect groundwater from oil and gas drilling. Among other objectives, the new rules require detailed disclosure of the chemicals used in hydraulic fracturing and other operations. The rules not only require disclosure of the chemicals used, but also the volume, concentration, and Chemical Abstracts Service (CAS) number.[114]

A coalition of environmental and industry representatives—initiated by the Environmental Defense Fund and Southwestern Energy and quickly expanding to a broader group composed of industry and environmental groups—is forming to draft a framework for regulation of hydraulic fracturing,. From news reports, it is apparent that the coalition is focusing its work on well construction and operation, since

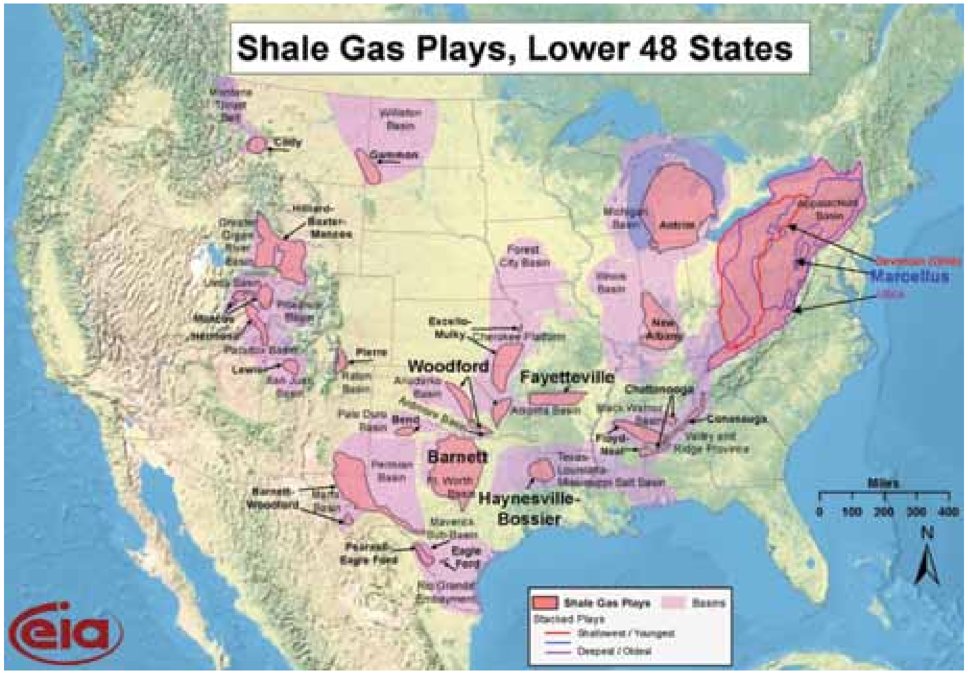


Figure 65: Shale Gas Plays, Lower 48 States

Source: Energy Information Administration[115]

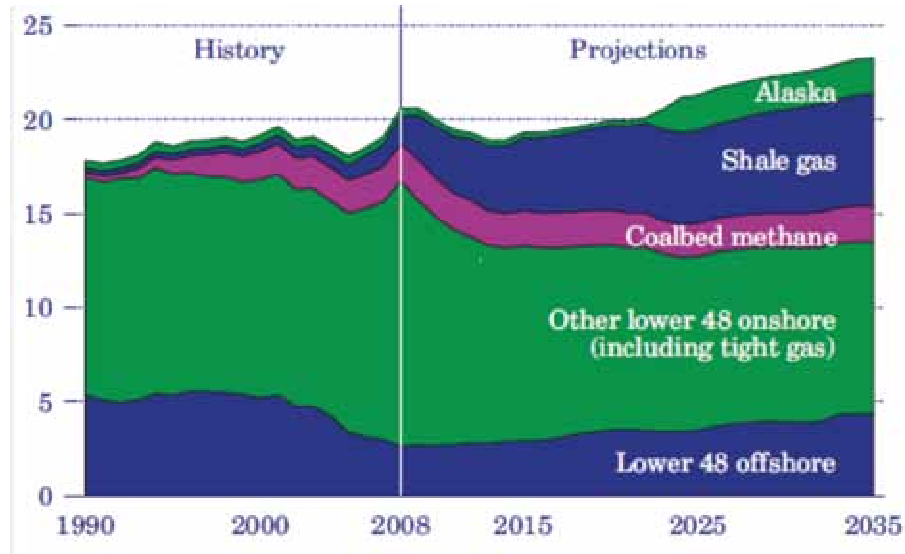


Figure 66: Natural Gas Production by Source, 1990–2035 measured in trillion cubic feet

Source: Energy Information Administration[116]

hydraulic fracturing is recognized as a subset of the well construction and operation process. In order for the nation to benefit from use of hydraulic fracturing, many details are being explored. These include how hydraulic fracturing is conducted, how to properly cement wells, how to position pipes in the wells, developing proper management procedures to control pressure in response to unexpected surges, and ensuring that wells are located or that fracturing operations take place beneath a layer of rock that can contain fluids from the fractures and keep them out of the drinking water. On December 1, 2010, Secretary of the Interior Ken Salazar announced that the DOE and the BLM will "consider issuing a policy that will deal with the issue of disclosure requirements with respect to the fluids that are used with hydraulic fracturing."

Shale Gas Considerations

In the United States, the largest shale gas plays include the Hilliard-Baxter-Mancos shale gas play and Piceance Basin in the Rocky Mountain region, Marcellus in the Northeast, and Barnett in Texas (Figure 65).

Figure 66 illustrates how EIA projects shale gas to be a significant source of growth in U.S. natural gas production. Before 2008, the contribution of shale gas to overall gas production was small.

According to the EIA, total natural gas consumption fell to 62.6 billion cubic feet (Bcf) per day in 2009, a drop of about 2 percent from the previous year's level; year-over-year consumption declined in the residential, commercial, and industrial sectors. The weakened state of the economy and warmer-than-normal winter weather were key factors in the drop in consumption. Natural gas rotary rig counts averaged 801 in 2009, substantially lower than the record-setting average of 1,491 in 2008."[117]

In a report of significance to Colorado, Richard Nehring (Nehring and Associates) presented *The Impact of Shale Gas* to COGA on July 7, 2010. Mr. Nehring pointed out that shale gas not only is transforming the U.S. gas market, but also will be disruptive. The disruption will be felt primarily in the Rockies, where dramatic growth in natural gas production has occurred; the region provided 106 percent of national growth. Nehring said the Rocky Mountain region has emerged because transitional sources were inadequate and unconventional sources reversed the national decline. He described what he called the "explosion" of unconventional gas production, with a doubling every

"The shale gas resource is a major contributor to domestic resources, but far from a panacea over the longer term." - MIT

decade. The Rocky Mountain region provided most of the two major types of unconventional gas (tight sandstone and coal-bed methane), making it the epicenter of such production.

Despite this growth, Mr. Nehring's main message was that much of this activity in the Rockies may be "relegated to the past tense," since the outlook for the area may no longer be quite so promising. He stated the problem is that gas prices may no longer be encouraging (for producers) because of the enormous resources available in shale gas, some of which is produced at relatively low cost. Nehring referenced six potential shale gas megaplays, including the Marcellus and Haynesville/Bossier plays, which he described as "truly world class" and available at relatively low cost.

The rapid growth of shale gas production has driven down the price, despite many predictions of a rebound. Shale gas drilling activity and commitments continue to grow despite low prices. The problem for the Rockies is that the Rockies only contain 10 percent of what many consider to be the shale gas potential that will be developed. He stated that the Rockies are now a mature, unconventional province, and realizing the remaining potential depends primarily upon downspacing, which yields lower recoveries per well and is uneconomic when gas prices are below $5 MMBtu. The shale gas industry is still not stabilized, illustrated by EOG Resources Inc. and Newfield Explorations Co. recently canceling a $405 million deal that had Newfield buying 50,000 acres in the Marcellus Shale.

The *Denver Post* reported in December 2010 that "Colorado permits for oil and gas drilling are expected to reach the third-highest level on record in 2010. Permits issued by the Colorado Oil and Gas Conservation Commission are projected to top 6,000 this year, up at least 16 percent from 5,159 in 2009. The increase suggests that Gov. Bill Ritter's tightening last year of regulations governing drilling — hotly contested by the energy industry — have proven manageable for producers. 'Judging by the permit volume, they've figured out a way to work with that,' said Thom Kerr, permit and technical services manager for the state energy commission.

Kerr said the PUC's recent ruling that natural gas will replace coal in several of the state's power plants should keep demand for gas strong in coming years. But the increase in 2010 drilling permits did not necessarily equate to a banner year for producers. Natural-gas prices remain depressed compared with levels from earlier in the decade. Gas production outside the Rockies has left the local market oversupplied.

The number of active wells in western Colorado's Piceance Basin has fallen from 91 in 2008 to 35 this year, according to Golden-based research firm Bentek Energy LLC. Bentek chief executive Porter Bennett said new gas discoveries and fast-growing production in Pennsylvania and other areas in the East and Midwest have lessened the demand for Colorado gas. 'All of a sudden you have all this gas in the East, and you don't need it from the Rockies,' he said. 'There's just no market for it, and as a result, prices are weak.'

Prices for Colorado and Wyoming gas are running near $3.80 per thousand cubic feet, compared with $5.55 last year.

Bennett said drilling permits can be a misleading indicator of market activity because producers don't always use all of the permits granted. More than one-third of the Colorado permits issued this year have been in Weld County, where advances in horizontal drilling techniques have created a mini-boom in oil production. 'We're seeing an uptick in activity' in both western and eastern Colorado, said EnCana USA spokesman Doug Hock."

MIT's report, *The Future of Natural Gas: An Interdisciplinary Study, 2010,*[118] states that: "The outlook for gas over the next several decades is in general very favorable. In the electric generation sector, given the unproven and relatively high cost of other low-carbon generation alternatives, gas could well be the preferred alternative to coal.

A broad GHG pricing policy would increase gas use in generation but reduce its use in other sectors, on balance increasing gas use substantially from present levels. International gas resources are likely less costly than those in the U.S. except for the lowest-cost domestic shale resources, and the emergence of an integrated global gas market could result in significant U.S. gas imports.

The shale gas resource is a major contributor to domestic resources, but far from a panacea over the longer term. Under deeper cuts in CO_2 emissions, cleaner technologies are needed. Gas can be an effective bridge to a lower CO_2 emissions future but investment in the development of still lower CO_2 technologies remains an important priority."

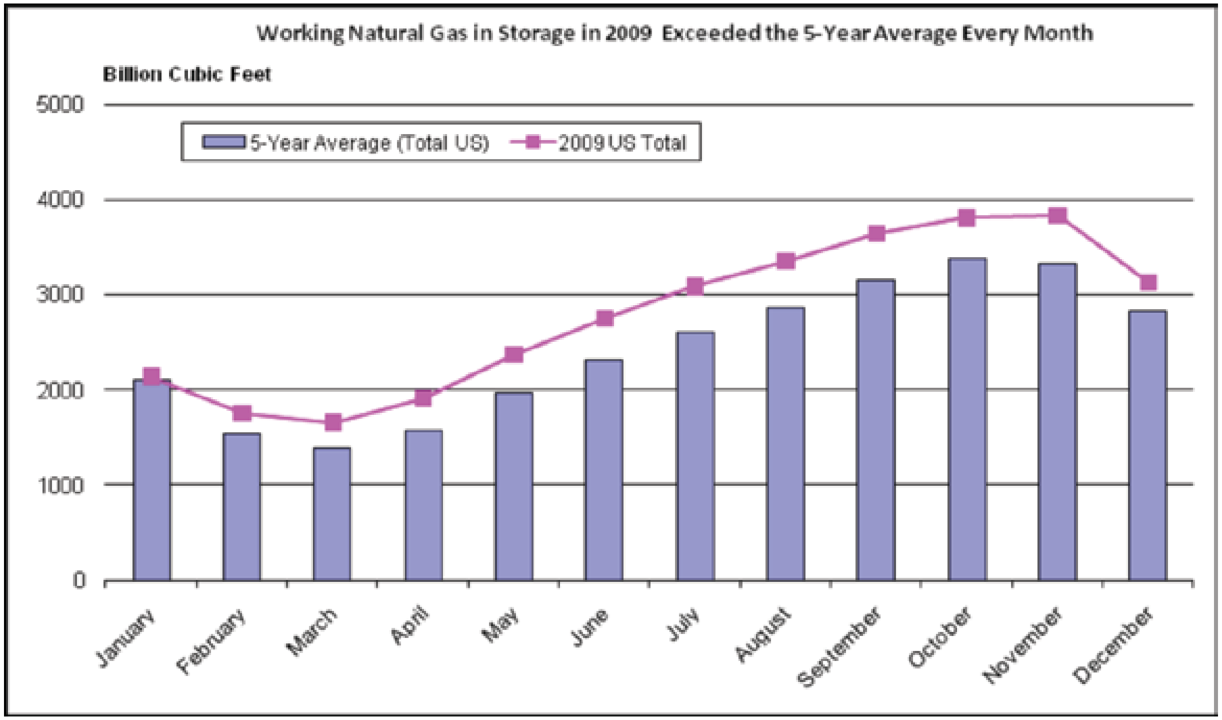


Figure 67: Working Natural Gas in Storage in 2009 Exceeded the Five-Year Average Every Month

Source: Energy Information Administration119

Natural Gas Pricing

Natural gas pricing is dynamic and influenced by three key drivers: 1) absolute storage; 2) weather normal balance; and 3) storage build/draw levels relative to trend.

Most of these factors currently are forcing gas prices down. In 2009, monthly storage levels exceeded the five-year average levels for every month of the year (Figure 67), while working gas stocks totaled about 99 percent of the estimated peak storage capacity of 3,889 Bcf. This indicates that, despite low prices, traders and other industry players are buying gas, presumably in the expectation that prices will eventually revert to historic averages.

In 2009, excess inventories and declining economic activity caused natural gas prices to fall to their lowest level in seven years. The wellhead price averaged $3.71 per million cubic feet (Mcf) during 2009, compared with $7.96 per Mcf in 2008.

Natural gas price volatility presents a challenge for the electric industry; it can have a greater effect than average absolute price levels. Price volatility has a major effect on resource planning models that evaluate the potential power supply cost under varying planning scenarios. Because these models consider the expected costs based on probability, they must incorporate the spectrum of possible prices at which gas might sell and reflect that fuel supply risk in their analysis.

The challenges associated with volatile prices may have been exacerbated by market rules that prevent most utilities from signing long-term gas contracts due to onerous credit requirements. In Colorado, this burden will be alleviated by new procedures required by HB10-1365 that resulted in PSCo entering into a ten-year gas contract.

Figure 68 shows trends of daily spot prices, and Figure 69 illustrates monthly prices on Henry Hub during the past decade. It illustrates the volatility exhibited by natural gas prices . At the time of the release of this report, natural gas was trading on the Henry Hub future at $4.10 per MMBtu.[120]

The American Public Power Association's July 2010 report, *Implications of Greater Reliance on Natural Gas for Electricity Generation*,[121] highlights a number of observations related to natural gas demand.

The report states that: "Virtually all expected growth in natural gas demand will occur in the electricity generation (EG) sector. The EIA projects that EG natural gas demand will increase by approximately 2 Tcf by 2030 even if carbon regulation is not adopted. Other projections of natural gas demand in 2030 for the electricity sector range from 6.8 Tcf to 10.7 Tcf. These electricity sector demand projections–which generally did not consider the additional regulations under consideration by EPA that will also encourage fuel-switching–are highly dependent on assumptions about electricity load growth, whether

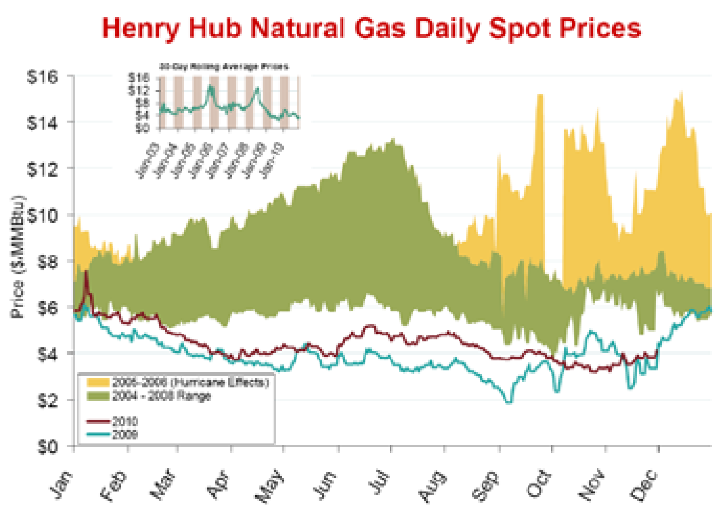


Figure 68: Henry Hub Natural Gas Daily Spot Prices

Source: FERC [122]

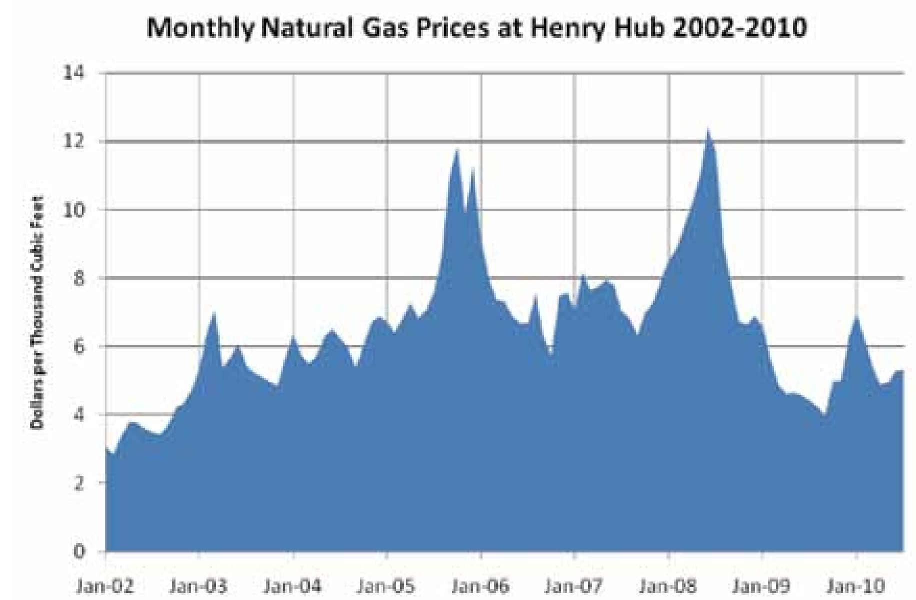


Figure 69: Monthly Natural Gas Prices at Henry Hub 2002-2010

Source: Energy Information Administration [123]

new nuclear power is built, the amount of renewable generation, whether CCS is commercially demonstrated and deployable for new plants or retrofits, and the number of offsets allowed to count towards carbon responsibility. The U.S. is heavily dependent upon coal-fired generating stations. A map of the location, and relative size, of these plants is illustrated in Figure 70. Switching all 335,000 MW of existing coal to natural gas today would create additional natural gas demand of 14.1 Tcf; EG demand, including existing gas-fired generation, would total 21.0 Tcf. The potential for additional EPA regulation of other hazardous pollutants and construction costs are encouraging some utilities to switch to gas now."

On Dec. 16, 2010 the consulting firm Charles River Associates announced a new report by its Energy & Environment Practice that found electric system reliability can be maintained as the industry undertakes coal plant retirements and pollution control retrofits to comply with upcoming clean air regulations from the EPA. The report, *A Reliability Assessment of EPA's Proposed Transport Rule and Forthcoming Utility MACT*, predicts the retirements and potential impact on electric reliability resulting from the Clean Air Transport Rule covering NOx and SO_2, and the forthcoming hazardous air pollutants regulations known as the Utility MACT. The report considered the impact on electric reliability at the RTO, NERC Regional, and NERC Subregional levels. Based on robust modeling after accounting both for already planned retirements plus those driven by EPA air regulations, the report predicts a total of 35 gigawatts of coal retirements in the Eastern Interconnection by 2015, less than 5 percent of the area's total electric capacity, and 39 gigawatts nationwide. The report highlights that the projected coal retirements in the aggregate are relatively small compared to past additions of new net generation capacity in the US. For example, from 1999 to 2004, US generating capacity increased by 177 gigawatts, more than four times what the report is projecting to retire in the US based on the upcoming EPA clean air regulations. The report also found that the average age of the projected retiring units in the Eastern Interconnection is 55 years, indicating that the retirements will impact primarily older plants nearing the end of their design life expectancy.

Natural Gas Generation

Because gas generation is a flexible resource that can be quickly ramped up and down, utilities often use it to meet peaks in demand that occur for only a brief time during a typical day and during peak seasons. During these so-called needle peaks in demand, baseload power source—principally coal and nuclear (in regions where nuclear power operates)—run at full capacity. As illustrated in Figure 71, rather than build excess baseload generation to serve during these few peak hours of the year, utilities use less capital-intensive gas peaking plants, which have a higher levelized cost of power than baseload plants but are dispatched only when needed via automatic generation control from the utility's control center.

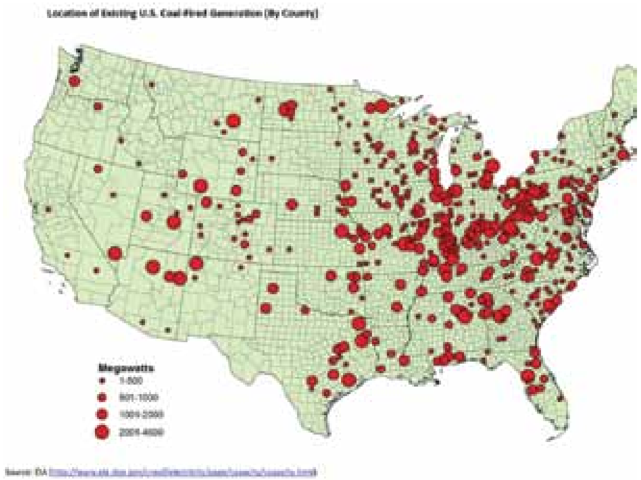


Figure 70: Location of Existing U.S. Coal-Fired Generation (by County)

Source: Energy Information Administration [124]

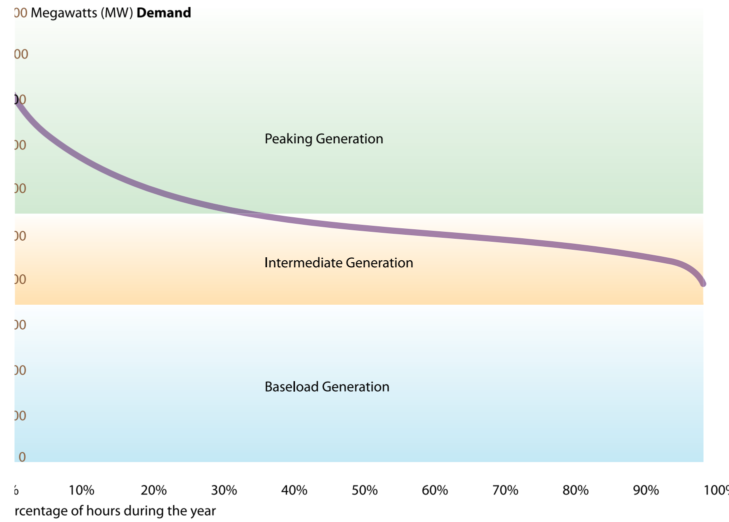


Figure 71: The Role of Various Types of Generation

Source: PSCo's 2007 Colorado Resource Plan [125]

A New Generation of Gas-Fired Power Plants is Needed

The STAR analysis assumes important technology developments in natural gas turbines will be available to simultaneously meet load growth, integrate variable resources, and reduce CO_2. Several studies have been conducted to redesign, optimize, and evaluate the economic performance of natural gas combined cycle with the best integrated technology CO_2 capture. According to one study[126] conducted by Cristina Botero, Matthias Finkenrath, Michael Bartlett, Robert Chu, Gerald Choi, and Daniel Chinn: "The Best Integrated Technology (BIT) concept for post-combustion CO_2 capture was evaluated for a 400 MW natural gas combined cycle power plant. The power plant was redesigned and optimized to include exhaust gas recirculation, an amine reboiler integrated into the heat recovery steam generator, and a low-cost amine unit capturing 90% of the CO_2 through absorption into a monoethanolamine solution. A detailed performance evaluation of the CO2-lean power plant as well as a cost estimation of the power island and CO_2 compression sections of the plant was carried out in order to evaluate the performance penalty of CO_2 capture, the additional costs associated with this technology, and the advantages relative to state-of-the-art solutions retrofitting the power plant with a conventional CO_2 capture unit."

Many studies have been conducted by industry and the DOE's National Energy Technology Laboratory (NETL) to develop "Next Generation" turbine power plants. NETL states that such turbines "… will require higher efficiencies with higher pressure ratios and turbine inlet temperatures than currently available. Yet these increases in gas turbine cycle conditions will tend to increase NOx emissions. As the desire for higher efficiency drives pressure ratios and turbine inlet temperatures ever higher, gas turbines equipped with both lean premixed combustors and selective catalytic reduction after treatment eventually may be unable to meet new NOx emission goals. New gas turbine combustors are needed with lower emissions than the current state-of-the-art lean premixed combustors." A summary report on an analysis regarding next generation turbines is available at the National Energy Technology Laboratory's website. [127]

Of significance to the STAR analysis, the modeling assumes that natural gas-fired combined cycle with carbon capture and sequestration technology is made available to the model beginning in 2017 at a cost of $1,412/kW and with a performance of 90 percent CCS. This assumption may be considered a "stretch." NETL reports that "significant challenges face CCS. The theoretical merit of CCS systems is the reduction of CO_2 emissions by up to 90%, depending on plant type. Environmental effects from use of CCS arise during power production, CO_2 capture, transport and storage. Issues relating to storage are discussed in those sections. Additional energy is required for CO_2 capture, and this means that substantially more fuel has to be used, depending on the plant type. For new supercritical pulverized coal plants using current technology, the extra energy requirements range from 24-40%, while for natural gas combined cycle plants the range is 11-22% and for coal-based gasification combined cycle systems it is 14-25%. Obviously, fuel use and environmental problems arising from mining and extraction of coal or gas increase accordingly. Plants equipped with flue gas desulfurization systems for SO2 control require proportionally greater amounts of limestone and systems equipped with SCR systems for NOX require proportionally greater amounts of ammonia." While CO_2 is drastically reduced (though never completely captured), emissions of air pollutants increase significantly, generally due to the energy penalty of capture. Hence, the use of CCS entails a reduction in air quality."

Despite these severe engineering challenges, incentives to develop the technology are emerging at an unprecedented rate. Research and development efforts are under way to reverse the trend line of investments in energy R&D (Figure 72). One important R&D effort is work that will result in natural gas plants that achieve a 90 percent reduction in CO_2 emissions including associated sequestration management. If the STAR "stretch" assumption proves to be unachievable, the goal may not be reached until several years past 2017, when the STAR modeling assumes that these advanced natural gas turbines with 90% CCS will be available. If the "stretch" assumption does not materialize by 2025 or 2030, for example, it will be increasingly challenging to achieve the CAP goal of an 80 percent CO_2 reduction in Colorado's electricity sector by 2050.

Positive steps are under way. The United Kingdom's Department of Energy and Climate Change plans to fund the world's first project to capture CO_2 from natural-gas-fueled power stations and pipe it under the seabed for permanent storage. Its press statement said: "We are opening our funding process to what could be one of the first ever commercial-scale CCS

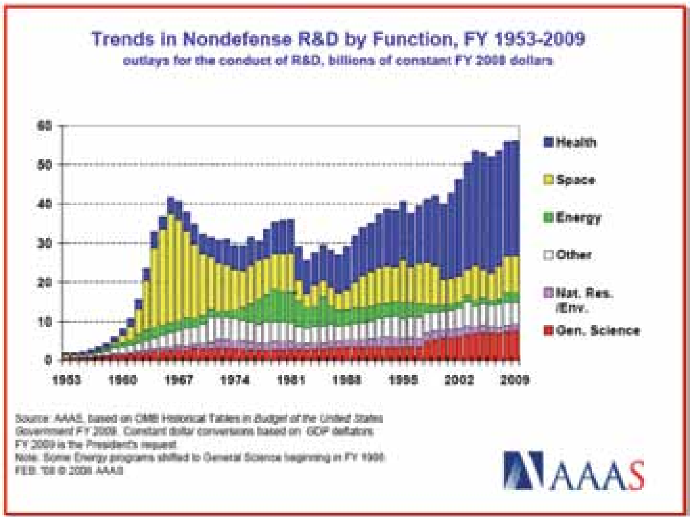


Figure 72: Trends in Nondefense R&D by Function, Fiscal Years 1953–2009

Source: American Association for the Advancement of Science

Utilities recognize the synergy that exists between the positive dispatchable characteristics of natural gas peaking plants and the naturally variable output of wind power generation.

projects on a gas-fired plant in the world. We won't be able to take the carbon out of all gas plants overnight, but we hope to support the process by investment in new technology now." According to Energy Minister Charles Hendry, the UK may host four CCS projects by 2020, with subsidies for the projects provided via a levy on electricity bills or through direct taxation. David Nickols, a London-based managing director at WSP Future Energy, said that, "Limiting emissions from gas-fueled power plants is vital. The country's use of electricity from gas-fired plants is expected to increase from about 40 percent of total electricity supplied in 2009 to more than 60 percent in 2020, with coal use set to decline."

Natural Gas Pipeline Infrastructure

In the last ten years, FERC has led significant policy initiatives to bolster domestic natural gas pipeline infrastructure (Figure 73). During this time, according to the EIA, more than 20,000 miles of natural gas transmission representing more than 97 Bcf per day of capacity were placed in service in the United States. Much of the increased capacity was added to access new supply sources and meet increased demand. In 2009, additions to the national pipeline grid totaled nearly 3,000 miles, representing an investment of about $9.9 billion in approximately 43 natural gas pipeline projects. Pipeline construction activity in 2009 was substantial compared to previous years, although it declined from the 2008 peak when close to 4,000 miles were added to the pipeline grid.

Rockies Express Pipeline

The $6.7 billion Rockies Express gas pipeline was completed in November 2009 (Figure 74). According to the Denver Business Journal, "the 1,679-mile pipeline goes from western Colorado to eastern Ohio. Kinder Morgan owns 50 percent of the pipeline, with the pipeline unit of San Diego-based Sempra Energy owning an additional 25 percent and ConocoPhillips owning the remaining 25 percent. The pipeline, the biggest built in the United States in 25 years, can move 1.8 billion cubic feet of natural gas a day (Bcf/d). At the peak of construction, about 10,000 people worked on the pipeline. Oil and gas companies in the Rocky Mountain region backed the Rockies Express because they hoped it would narrow the gap between regional prices and the price natural gas fetched on the national market."

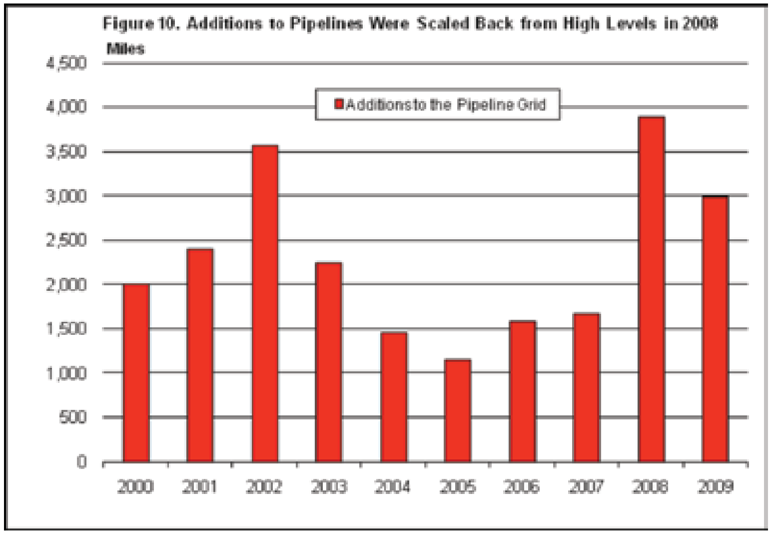


Figure 73: Pipelines Additions in the Last Decade

Source: Energy Information Administration [128]

Figure 74: The Rockies Express Pipeline

Source: big3news.net [129]

Ruby Pipeline Project

The Ruby Pipeline Project represents an investment of approximately $3 billion in new pipeline infrastructure that will connect natural gas reserves in the Rocky Mountain region with markets in the western United States. The project includes approximately 680 miles of 42-inch natural gas transmission pipeline, connecting Wyoming and Oregon. The project, with an initial design capacity of up to 1.5 Bcf per day (BcF/d), will traverse portions of four states. The FERC approved the Ruby Pipeline's application and issued a certificate for the project; construction began in July 2010, with an estimated in-service date of spring 2011. In contrast to most electric transmission project schedules—which can run from seven to ten years—the project spanned two years from filing date to project completion.[131]

Kern River Pipeline Expansion

Before the Rockies Express pipeline was built, the Kern River Gas Transmission Company pipeline was the only major interstate natural gas system originating in the Rockies that transported natural gas to other regions. The Kern River pipeline originates in southwestern Wyoming, travels through Utah and Nevada, and terminates in southern California—a total distance of 1,680 miles with a capacity of 1.8 Bcf/d (Figure 75). In the last decade, another major addition to the U.S. pipeline infrastructure occurred in Wyoming (and northern Colorado) with expansion of intrastate pipelines in the Green River and Powder River basins and an increase in interstate pipeline capacity toward the Midwest and West.

Figure 75: The Kern River Expansion Project

Source: Kern River Gas Transmission Company [130]

Additional Pipelines

Several other projects are being planned and constructed in the Rockies. For example, Questar Pipeline and Enterprise Products Partners announced plans to construct a new 2.5 Bcf/d natural gas pipeline from the Piceance Basin to the Enterprise natural gas processing facility near Meeker, Colorado. If completed, the White River Hub will provide interconnections to at least six other pipelines. [132]

Renewable Energy and Natural Gas

The relationship between renewables—principally wind—and natural gas has evolved during the last decade, particularly given the growth in the wind industry. In many instances, gas and wind developers were in direct competition as each attempted to sell its electric output through power purchase agreements (PPAs) with utilities through all-source competitive request-for-proposal (RFP) solicitations. Many utilities, including PSCo, eventually proceeded with PUC rules that segmented the RFP bidding so eliminate head-to-head competition between renewables and natural gas. The segmentation recognized renewables and wind have different roles (including energy and capacity) in the electricity sector. With increased wind penetration and operational experience, leading-edge utilities now recognize the synergy that exists between the positive dispatchable characteristics of natural gas peaking plants and the naturally variable output of wind power generation.

As levels of renewable development increase due to state RPS policies, and given the positive characteristics of no-fuel and pollution-free generation, large wind projects are expected to continue to share the spotlight with new gas generation as utility-scale technologies of choice (Figure 76).

The wind industry depends to a major extent upon the value provided by natural gas generation to help integrate its variable output. The natural gas industry is capitalizing on emerging opportunities to help utilities meet RPS targets. Natural gas turbine manufacturers are motivated to engineer their generators with ever-improved quick-start and ramping capabilities to accommodate variable renewable generation. Along with federal research and development assistance, the industry also is developing methods for either precombustion or postcombustion CO_2 capture.

In 2008, when gas and electricity prices were rising, renewable project development plans were particularly attractive. Many natural gas developers saw the opportunities and entered the wind development business. Although the wind and natural gas development industries have distinct origins, it is now common for natural gas developers to share capabilities with wind developers, and vice versa.

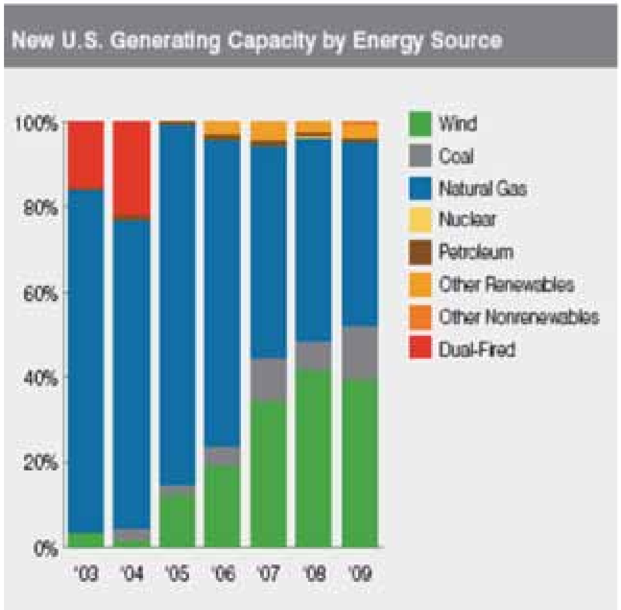


Figure 76: Wind's Increasing Contribution to New Capacity Additions[133]
Source: Pure Energy Professionals

A strategic alliance has been announced between the American Council on Renewable Energy (ACORE) and the Natural Gas Supply Association (NGSA) proposing that energy regulators adjust their rules to allow natural gas power plants and renewable energy projects to participate jointly in electricity markets.

"The leadership of ACORE and NGSA have agreed to promote a collaborative industry effort to identify federal policies that may be hampering natural gas and renewable partnerships in competitive power markets," ACORE's Executive Director Mike Eckhart said. "We have a couple of preliminary ideas and are excited to explore those and others in pursuit of options that align the industries and contribute to a stable and well-functioning electric grid."

Conclusion

Because most observers expect natural gas prices to remain reasonably stable over the next five years and more, the projected comparatively low prices will likely dampen otherwise upward pressure on wholesale electricity prices. While the country vigorously attempts to return to long-term economic growth following the economic downturn, the outlook in the short term will continue to be challenging for the electric power industry. This is especially true due to competing interpretations and projections for long-term fossil fuel supplies, power demand, prices, and regulatory policies. A major factor in projecting natural gas prices during the next five years will likely be whether the promise of plentiful and inexpensive shale gas proves out. That scenario will be conditioned in large part on whether identified environmental concerns can be effectively addressed.

Results of the STAR modeling analysis quantify the need for a substantial increase in natural gas generation in Colorado's electric power system, amounting to approximately 6,500 MW of additional gas-fired capacity by the year 2050 under a load growth scenario of 1.7 percent per year. This increase is necessary to meet load growth, displace aging coal-fired generation, and provide necessary firming and integration of renewable resource generation. Natural gas will play a major role in producing better environmental performance in the electricity sector, including CO_2 reductions. Success in the research and development of natural gas advanced combined cycle plants with carbon capture and storage will help Colorado meet its long-term CO_2 reduction goals. State-of-the-art forecasting is increasingly proving its value to enable efficient co-scheduling of wind, solar, and natural gas power. Advances in this area will allow the industry to maximize every megawatt of renewable capacity, resulting in a more reliable power supply, with attendant benefits—including environmental—and more stable prices.

Colorado policy-makers should conduct a comprehensive benefit-cost analysis (including economic and environmental measurements) to review the age, performance, continuing operations and maintenance costs of the remaining coal-fired generation stations in the state. Part and parcel of the review should be a determination of the opportunities for gas-fired generation, or renewable energy, or both, and the associated transmission and pipeline infrastructure requirements and policy guidance that will allow these cleaner resources to displace the retirement of coal-fired generation.

7. The Role of Balancing Authorities

REDI Review

According to the REDI report, Colorado could benefit from even stronger interstate coordination among the players who plan new generation and transmission. The power system currently operates under a smaller balancing authority area than might be desirable, creating disadvantages for wind and solar power integration and potentially increasing the cost of delivering renewable power to Colorado customers. Without a single regional balancing authority area, Colorado may risk increased costs of transmitting power beyond what such prices might be under more coordinated transmission pricing systems.

The REDI report's conclusions included a suggestion that stakeholders examine the costs and benefits of a regional balancing authority area of which Colorado would be a part. Colorado should strengthen its engagement with neighboring states in relation to governance and operation of the transmission system over a multistate area.

Overview of Independent System Operators/Regional Transmission Organizations

North America's power grid is composed of ten Independent System Operators/Regional Transmission Organizations (ISOs/RTOs). This structure is largely the result of deregulation that occurred in many states more than a decade ago that separated generation from transmission and distribution. ISOs and RTOs serve two-thirds of U.S. electricity customers and more than 50 percent of Canada's population. Figure 77 shows the locations of the ISOs and RTOs in North America.

ISOs/RTOs serve as third-party operators of the transmission system, independent of generation. ISOs/RTOs provide fair and nondiscriminatory transmission access for the benefit of customers and solve many inherent conflicts caused by contractual transmission rights to ship power over the lines, thereby obtaining the most economical dispatch of energy. Because they are independent, ISOs/RTOs ensure that no preference is given in the dispatch of a utility-owned generator over generation from a competitive source. Proponents of this ISO/RTO structure maintain that it delivers greater value to customers at every level of the utility supply chain, compared to the vertically integrated approach of non-ISO/RTO markets.

ISO/RTO duties include conducting "spot" markets (often referred to as "Day 1" or real-time markets) and "day-ahead" markets (often referred to as "Day 2"). They also provide necessary transaction support. ISOs/RTOs engage in regional planning for transmission infrastructure construction. ISOs/RTOs oversee both market and transmission functions and are regulated by the FERC. As a further check to ensure fair-market behavior, each organized market is overseen by an independent market monitor. ISOs/RTOs are designed to provide all stakeholders in the market with input into the region's activities. The transparency of a fluid electric power market helps ensure markets that are fair and open to competition. The ISOs/RTOs structure also helps improve coordination and electric power reliability between regions, resulting in more efficient power flows and transactions.

In contrast, in markets that maintain the traditional regulatory utility model, power must cross numerous individual utility areas, incurring transaction

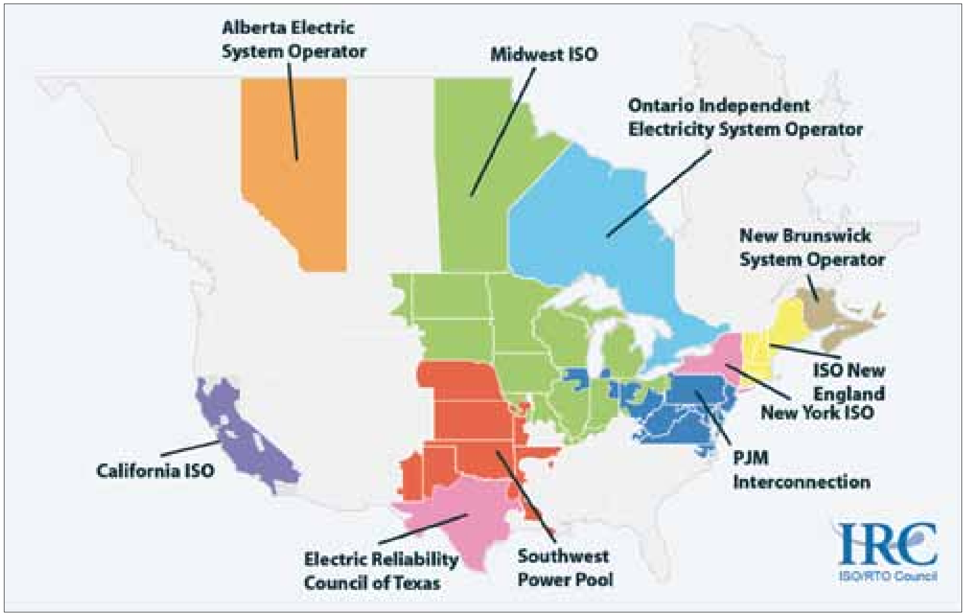


Figure 77: ISOs and RTOs in North America

Source: ISO/RTO Council [134]

charges at each utility border. The ISO/ RTO structure also enables pooling of generation resources, which potentially results in fewer assets being required to meet peak demand. Reducing the need for new power plants saves customers money and reduces CO_2 and other emissions.[135]

As is the case in most of the western United States (with the exception of much of California) and the southeastern U.S., Colorado is not part of an ISO/ RTO market. Instead, it is structured as a traditional regulatory utility model. According to the Electric Power Supply Association, "Under this regime, vertically integrated utilities retain functional control over the transmission system and therefore choose what generator is dispatched when."[136]

Among the reasons many states in the west remain as vertically integrated electric markets are the result of individual histories and the political preferences of the major western utilities. An analysis of this history, including the pros and cons, is beyond the scope of the STAR report.

Colorado and the ISO/RTO Structure

Colorado lies on the eastern portion of the Western Interconnection and lacks robust transmission interties with other electric markets that would achieve the economy of scale benefits experienced in ISO/RTO market structures. The markets in other parts of the country tend to be characterized by large metropolitan areas in close proximity to one another. For these and many other reasons, it may be unlikely that Colorado and other western states will form an ISO/ RTO structure in the foreseeable future. As a result, it may be more difficult for Colorado to integrate variable sources, such as wind energy. Although it may not be possible to achieve the ISO/RTO structure for some years to come, certain utilities in the Western Interconnection are pursuing several initiatives to address the integration of variable resources.

Colorado lies on the eastern portion of the Western Interconnection and lacks robust transmission interties with other electric markets to achieve the economy of scale benefits seen by ISO/RTO market structures.

Balancing Authorities

One initiative would create a virtually consolidated balancing area. The virtual balancing authority could have some of the benefits—such as diversity of resources—inherent to larger balancing areas, without necessitating physical consolidation. According to the NERC, a balancing authority is the responsible entity that integrates resource plans; maintains a load interchange generation balance within a balancing authority area; and supports interconnection frequency in real time. A balancing authority area is defined as the collection of generation, transmission, and loads within its metered boundaries. In the past, balancing authorities were called control areas. Certain reliability standards measurementsand other matrices cannot be met with large penetrations of variable resources. To address United States, these issues, several sources have proposed a virtual balancing authority that would allow the reliability matrices to not only be met, but benefit from a diverse set of resources.[137]

Western Interconnection

WECC is one of six regions within the NERC. At present, the Western

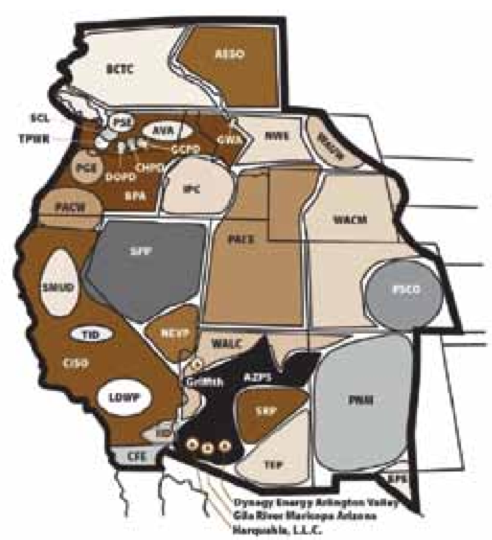


Figure 78: Western Interconnection Balancing Authorities

Source: WECC [138]

Interconnection is divided into 37 balancing authority areas (Figure 78). One of the two balancing authorities in Colorado is operated by Western Area Power Administration Colorado-Missouri (WACM); the other is operated by PSCo.

Benefits of Balancing Area Cooperation

The benefits of combining control areas include cost savings to utilities and renewable developers. As renewable resources increasingly penetrate the overall resource mix, control areas are looking for ways to continue to reliably operate their systems and still accommodate the general variability of renewable resources. As they do this, they will strive to maintain a low cost structure. Consolidating control areas, either physically or virtually, has key benefits, including reducing not only the variability of both load and resources, but also costs. According to NREL and GE's May 2010 *WWSIS* "From an operational perspective, balancing area cooperation can lead to cost savings because reserves can be pooled." The study included a sensitivity analysis, running the WECC as 106 zones (which are roughly equivalent to balancing areas in the Southwest, although there are several zones per balancing area in the Northwest) versus five regions.

Figure 79 shows the $2 billion savings in WECC operating costs in the 10 percent penetration case. Significant savings result from sharing reserves over larger regions, irrespective of the renewable on the system.

Physical Consolidation of Control Areas

Consolidating control areas physically was addressed in detail on page 81 of the REDI report: "Colorado needs to study the costs and benefits of a larger balancing area footprint than currently exists for operating the electric system in the Rocky Mountain Power Area, including alternatives for multi-state government and oversight."[139] This option for reducing costs as part of any long-term goal of increased renewables penetration and the resulting carbon reduction and other benefits has been cited in many studies.

- **American Wind Energy Association:** In a report for the 7th Integration Workshop of Large Scale Integration of Wind Power, *The Ability of Current U.S. Electricity Structure & Transmission Rules to Accommodate High Wind Energy Penetration,*[140]

  Robert Gramlich and Michael Goggin of AWEA describe the characteristics of an ideal market structure for integrating wind. One key characteristic is how a larger balancing area (authority) with more access to neighboring markets has significantly lower costs for wind integration. Larger balancing areas provide more opportunity for excess generation in one region to be offset by shortfalls in generation in another. This effect is true even for systems without wind energy. It is often even more pronounced for wind energy, however, since variations in wind output tend to be less correlated over larger geographic regions.

  A wind integration study conducted in Minnesota in 2005 found that consolidating the state's four balancing areas into one would reduce the requirement for regulation services by 50 percent.[142] In addition, a larger balancing area provides a larger pool of flexible resources that can be used to accommodate variations in electricity supply or demand. The ability to export power to neighboring regions is particularly useful during minimum load situations in regions that have many must-run generators, because it allows excess power to be exported to nearby regions."[143]

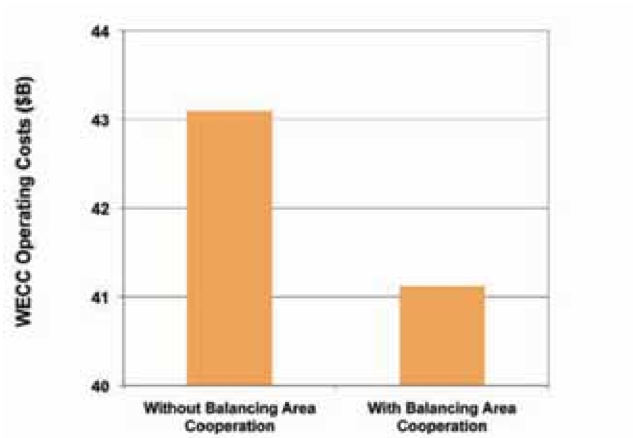


Figure 79: WECC Savings with Balancing Area Cooperation

Source: NREL 2010, Western Wind and Solar Integration Study[141]

- **North American Electric Reliability Corporation:** NERC's general conclusion is that geographic diversity can reduce the cost of using more large-scale wind power and solar power, but only if all generation resources in the region are managed day to day and hour to hour under a single set of protocols. A system that increases coordination of transmission resources can enable more efficient transmission pricing, which ultimately benefits generators and electric customers. NERC's 447-page *2009 Long-Term Reliability Assessment* [144] provides detailed information about robust plans for renewable generation.

- **National Renewable Energy Laboratory:** NREL's *WWSIS*[145] discusses three key benefits of balancing area cooperation: 1) aggregating diverse renewable resources over larger geographic areas reduces the overall variability of renewables; 2) aggregating the load reduces the overall variability of the load; and 3) aggregating the nonrenewable balance of generation provides access to more balancing (and more flexible) resources. Figure 80 shows the reduced-variability benefit arising from aggregating smaller transmission areas into the WestConnect footprint.

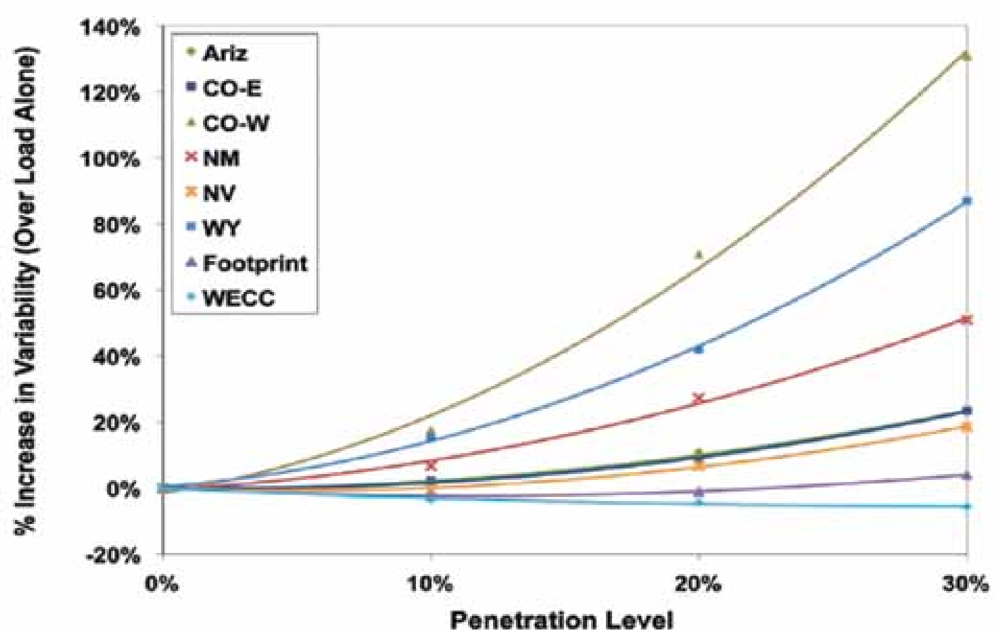


Figure 80: Variability and Aggregation of WestConnect Transmission Areas

Source: NREL 2010, WWSIS [146]

Variability for small areas such as Colorado-West or Wyoming increases significantly as renewable penetrations increase from 10 percent to 30 percent. The effect becomes even more extreme for specific balancing areas within a state. When the balancing areas across WestConnect are aggregated, however, variability increases only slightly with increased renewable penetrations, and even decreases slightly WECC-wide.[147]

- **Wyoming Infrastructure Authority:** The Wyoming Infrastructure Authority's (WIA's) October 2009 *Report to the Legislative Task Force on Wind Energy Transmission Sub-Committee*,[148] drew similar conclusions: "A potential operational benefit of a broader collector system could be to expand the pool of resources used to balance the system. These resource pools are called 'balancing areas' within the electrical industry. Each area is operated by a group of system dispatchers that keep the flows in and out of the system balanced at all times. It has been found that the expansion of these balancing areas allows more resources to be pooled, such that the impacts of intermittent resources are mitigated to an extent. Wyoming is split between two WECC certified Balancing Areas. The eastern portion of Wyoming is included within a balancing area operated by the Western that includes Colorado and Nebraska. The western portion of Wyoming is included within a Balancing Area operated by PacifiCorp that includes Utah and Idaho. While each of these Balancing Areas is large on their own, both operators are looking for ways to share resources more effectively to help integrate wind resources. Elimination of the barriers between the eastern and western portions of the transmission systems within the state of Wyoming could help facilitate the statewide development of resources to supply multiple markets."

Virtual Control Areas

Physically combining balancing areas is straightforward, but may not always be desirable. Various analyses examine the physical consolidation of balancing areas, while others cite that similar benefits can be obtained by "virtual balancing area consolidation." Such mechanisms may include all or some aspects of dynamic scheduling, intra-balancing area scheduling at subhourly time steps, or other wide-area economic dispatch concepts that do not require actual physical balancing area consolidation. In a white paper drafted by WECC's Variable Generation Subcommittee Market Workgroup,[149] the authors state that, "What matters is the size and dispersion of load, penetration of the variable renewable resources, and conventional generation fleet. Bigger is generally easier to balance, but size can be obtained either virtually or physically."

WestConnect Efforts at Market Enhancements

The WestConnect members, which in Colorado include PSCo, Western and Tri-State, have a number of market enhancements under way, each of which has unique attributes valuable to virtually increasing the size of the WestConnect footprint and improving the members' ability to engage in more flexible power and energy exchanges. A summary of each of these market enhancements follow.

WestConnect Regional Transmission Service

This effort, commonly referred to as the "WestConnect Pricing Experiment," provides transmission customers the opportunity to purchase transmission service across multiple systems and pay a single rate for that service. The product is seamlessly offered through the WesTTrans OASIS, also a WestConnect-developed product.

Virtual Control Area

In conjunction with participation of utilities throughout the Western Interconnection and Canada, the Area Control Error (ACE) Diversity Interchange (ADI) is a system that integrates the ACE of all participants. This integration reduces the regulation burden on individual participants and allows for a more regional approach to dampen the effect of load and generation variability.

Intra-Hour Transmission Purchasing and Scheduling

One challenge in operating in a non-RTO environment is the requirement that sales and purchases of energy—and the associated reservation of transmission service (via OASIS) and scheduling (via e-Tag)—are for minimum one-hour, starting at the top of the hour. Along with participants throughout the Western Interconnection in a group known as the "Joint Initiatives," WestConnect members are standardizing their OATT Business Practices to allow transmission customers to purchase and schedule transmission service on a sub-hourly basis. This effort will allow more flexibility in the energy market and provide opportunities for economic sales and purchases when, for example, unexpected wind generation events occur. The business practices and associated procedures are currently on schedule for implementation by the summer of 2011.

Intra-Hour Transaction Accelerator Platform (I-TAP)

Another effort to improve operation of the non-RTO market in the West, I-TAP—another Joint Initiatives activity—is a series of systems that together will speed up and simplify the components needed to successfully trade power on the market. I-TAP integrates instant messaging technology, OASIS, and e-Tag functionality to support energy trades. The technical specifications for I-TAP are complete, and participants are working with OATi on factory testing during the current product development stage. I-TAP is expected to "go live" in mid-2011.

Dynamic Scheduling System (DSS)

The DSS will provide a more efficient way to implement dynamic schedules. A dynamic schedule changes the regulation requirements of a load or generator from the owner/seller to the purchaser. In other words, a dynamic schedule (also sometimes called a dynamic transfer or pseudo-tie) is used to "virtually" place a load or generator into a different balancing area.

Dynamic schedules have been used for decades. DSS will solve the problem of the amount of time required to implement a dynamic schedule between two parties. Current systems require weeks or even months of advance preparation, while the DSS will allow dynamic schedules to be implemented within minutes. It is expected that the advance of DSS will increase the number of dynamic transfers between balancing areas, thus allowing more efficient use of generating resources and reducing overall regulation requirements and generator imbalance charges. Wide-ranging DSS use should also reduce wind curtailments caused by unexpected wind generation combined with a lack of regulation up-or-down in the host balancing area.

Western Electricity Coordinating Council

The WECC has stated that the Western Interconnection needs more reliability tools to address the future high penetration of renewables. To develop these tools, it has established the WECC Seams Issues Subcommittee, which is analyzing and reviewing the Proposed WECC Efficient Dispatch Toolkit. The two-part WECC reliability proposal will focus on the first Seams tool and Energy

Reducing costs associated with balancing authority functions is key to most efficiently integrating the increasing fractions of renewable energy into the electric system.

Imbalance Service (EIS) tool. The Seams tool will strengthen reliability coordinator functions. The EIS tool will increase efficiency and reliability for balancing areas, transmission providers, and energy suppliers that work to balance generation and load. The EIS tool, which will act much like a virtual control area, will include participating balancing areas in the WECC footprint. WECC will conduct a cost-benefit analysis of its proposed reliability toolkit to manage energy imbalance and congestion redispatch on the bulk electric system. Such analysis, due in April 2011, is intended to support the thesis that the lowest-cost alternative is to use the toolkit for balancing authority functions. [150]

By building on the momentum occurring in the industry, it is clear that reducing costs associated with balancing authority functions is key to most efficiently integrating the increasing fractions of renewable energy into the electric system. In the July 2009 NREL report, *Impact of Electric Industry Structure on High Wind Penetration Potential*, the authors introduce a system evaluation tool that was developed for use as a spreadsheet-based instrument to assess how well the structure of a balancing authority or region accommodates integration of large amounts of wind generation. The hypothetical large, progressive balancing authority receives a fairly high score for having market structures and physical characteristics that help reduce wind integration costs.[151] To reap the benefits of the consolidated balancing authorities, transmission lines must be constructed to alleviate congestion so energy can reach the area of need.

As the market looks to the future, WECC is expected be at the forefront of integrating the various balancing authorities, either virtually or physically, to improve reliability and reduce overall integration costs of renewable energy sources. The results of the pending WECC Seams Issues Subcommittee's report, due in 2011, will provide a detailed cost-benefit analysis for consolidation of efforts in the West.[152]

Other entities in the Pacific North-west, such as the Bonneville Power Administration with its Northwest Wind Integration Action Plan, are considering how to best integrate up to 6,000 MW of wind that may be developed during the next several years.[153] Also in the Northwest, the Northern Tier Transmission Group (NTTG) has established an Area Control Error (ACE) Diversity Interchange (ADI) pilot program to help providers in that part of the country share regulation across regions. This pilot program has gained significant outside interest (WestConnect has joined the NTTG ADI project) because it is the first example of how enhanced cooperation between key control areas can deliver markedly improved efficiencies at low cost.[154]

Conclusion

Consolidating balancing authorities, either physically or virtually, has advantages for integrating greater penetrations of variable renewable resources. With its cost-benefit analysis and toolkit scheduled for release in early 2011, the WECC Seams Issues Subcommittee should provide a good alternative for using balancing area functions to address congestion involving the lowest-cost alternatives. Several other entities also have explored and provided validation with studies of the benefits of balancing authority consolidation. It is expected that the Colorado balancing area operators will be interested in the results of the analysis provided by WECC with use of the toolkit. Consolidation will support both the goals of increased reliability and a reduction in overall integration costs for long-term support of renewables in Colorado.

Colorado utilities should work with key stakeholders and report to the legislature and the PUC regarding their findings to determine what policy changes and modifications in practice should be initiated to ensure that Colorado benefits by either physical or virtual consolidation of the state's two balancing authorities.

8. Cost Recovery and Cost Allocation Challenges

REDI Review

According to the REDI report, "Current efforts under way to develop Colorado's transmission infrastructure are showing some improvements in several areas, for example, SB07-100. Although new opportunities are apparent, renewable energy development and transmission infrastructure improvements also face many identifiable challenges. These include, but are not limited to, addressing the often-contentious issues related to cost allocation and cost recovery."

Definitions of Cost Recovery and Cost Allocation

Cost recovery describes how utilities receive recovery on capital costs expended. Cost recovery for transmission investments is often contentious because the regulatory process traditionally has a tendency to limit cost recovery to investments in near-term infrastructure. This results in forgoing more beneficial, higher-voltage, longer term investments. Sub-optimal investments are the result. We see this in Colorado when it comes to lower transmission voltages being planned compared to what will be needed if the state is to build out our vast renewable resources according to a strategic vision of the electricity sector out to 2050 and beyond.

Cost allocation is a term used to describe how costs of a capital investment such as a transmission line will be allocated to entities that use the line or benefit from the line. Regulators are increasing their consideration of the cost allocation issues, and 2011 appears to be headed for an opportunity to address this particularly thorny issue.

The basic approach to cost recovery is that a utility must be convinced that it is willing to take an investment risk, and that it can convince its regulator (or, in the case of Tri-State, its board of directors) to approve the costs for capital items such as construction of new infrastructure, e.g., generation, transmission, and distribution facilities. In the case of the PUC, after an investigation and hearing on the prudency of the investments, if the regulator approves the expenditure, the utility then has the expectation to recover the costs of the investment through rates charged to its customers. This process was used for most of the past century, and utilities were generally expected to invest in, and receive full recovery for, all "used and useful assets" that went into its rate base.

Cost recovery regarding transmission is contentious because the process tends to provide an incentive for a utility to invest primarily in infrastructure needed to meet its near-term customer requirements. There are many reasons for this. The short-term focus may result in transmission investments that are undersized compared to what otherwise might be best from a longer-term, or a regional, perspective. For example, a higher-voltage transmission line provides far greater economies of scale than a lower-voltage transmission line. Building the most cost effective line for the long-term is the most responsible approach for a robust transmission system. The higher-voltage line may be a larger investment than the utility wants to construct, however, because the company does not want to risk receiving less than full recovery from its regulators or governing board.

"Cost allocation" is the term used to describe how the actual costs of a capital investment such as a transmission line will be allocated to the various entities that use the line. These entities include utilities, developers, generators, and electric customers. This issue receives considerable attention because the outcome will define the exact costs to be paid by the various stakeholder groups for a regulated asset such as a transmission line that provides a wide range of benefits. The cost allocation question is at the heart of FERC's efforts through its NOPR to define a common cost allocation methodology that supports its national goals, and that also allows various regions of the country to enact the most appropriate rules for them.

WIRES[155] has defined the cost allocation issue as follows: "As things stand today, if transmission lines are built specifically to interconnect a generator, that plant may be responsible for the costs. If a line is large or configured to benefit customers over an entire system, or even a region, all such beneficiaries may be responsible. The merits of such different approaches– i.e., "participant funding" versus "socialization" and measures in between– depend on facts (e.g., grid features, fuel mix) and policy preferences. There are no national standards for cost allocation and so each utility or RTO

Potential changes to current cost allocation methodologies are being evaluated to provide incentives for potential expansion that will result in more utility-scale renewable energy for Colorado, and potentially for regional interstate transmission line expansions.

decides who will pay in each instance, creating uncertainty. The challenge is that massive new transmission additions that implement smart grid or bring renewables to market or ensure reliability will come at an economic price. Should the per ratepayer impact be kept low by broad socialization of the costs? When is this equitable and when not?"

These two terms—cost allocation and cost recovery—are sometimes confused and used interchangeably, but their meanings are distinct and different. For example, once the capital costs to build a certain size asset, such as a transmission line, are incurred, then all reasonably incurred expenses are expected to be recovered in rates paid by the user of that line. Capital costs will be allocated to the various customer classes and incorporated into tariffs defined by regulators and paid as part of the customer's monthly bill to the transmission owner.

Potential changes to current cost allocation methodologies are being evaluated to provide incentives for potential expansion that will result in more utility-scale renewable energy for Colorado, and potentially for regional interstate transmission line expansions.

A proposed regional line such as the High Plains Express Transmission Project for example, does not fit into state public service commission and cooperative generation and transmission associations' cost allocation procedures. HPX's proposed route (or routes) would be built in four states, so the question becomes how to handle cost allocation and cost recovery when multiple beneficiaries exist in four states.[156]

To illustrate why the cost allocation issue is so complex—and often quite controversial—a discussion of the primary cost allocation methodologies follows.

- **Postage Stamp Method:** This allocation simply divides the revenue requirements associated with specific investments on a *pro rata* demand basis. Postage stamp allocations are based upon geography and can either be so narrow as to cover an individual load-serving entity or so broad as to cover multiple regional transmission organization (RTO) footprints. This allocation methodology requires a generator, or it requires that the entity causing the transmission upgrade/new project to be constructed fund the full investment. This keeps the transmission owner's native-load customers from bearing any costs, but allows them to reap the benefits associated with the new generator or transmission project.

- **Beneficiary Pays:** New or upgraded transmission projects' investments are paid by those customers (retail and wholesale) shown to benefit from the project. The benefits, measured over a specific period of time, typically are calculated based on the parties first requesting the facilities to satisfy some specific purpose, such as serving their load from a new generator.

- **Open Season (Market-based):** This type of allocation typically is applied to new transmission projects and often is best applied to direct-current lines. Under this cost allocation method, the transmission owner will hold an "open season" for generators or load to subscribe to capacity of the new line.

- **California Independent System Operator (CAISO) Financing:** CAISO created a cost allocation methodology for location-constrained resource interconnections (LCRIs). This methodology is applied solely to projects that involve new transmission to energy resource areas (ERAs, which are defined by the CPUC and CEC).

- **Toll Road Concept:** Charge for use of facilities is assessed on calculated usage. Actual flows and simulation programs are used to determine energy market transaction and participation levels.

- **Highway-Byway Zones:** New and existing transmission facilities are separated in 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, energy markets, and sharing of reserves.

- **Balanced Portfolio:** The balanced portfolio is a modified postage stamp methodology that ensures fair treatment across the RTO footprint.

Summary of the FERC's Notice of Proposed Rulemaking on Cost Allocation and Planning

FERC is an independent federal agency created by Congress, in part to regulate interstate transmission of electricity. Its jurisdiction covers both economic and infrastructure regulation, and it has significant authority with respect to regulating and overseeing domestic energy markets, including interstate electric transmission.

While FERC has a long history of seeking to create energy markets that are not unduly discriminatory or preferential, its pursuit of these goals advanced significantly when FERC Issue Order No. 888 in 1996. The order requires all public utilities that own, control, or operate facilities used for transmitting electric energy in interstate commerce to have on file open-access nondiscriminatory transmission tariffs that contain minimum terms and conditions of nondiscriminatory service. More simply, Order 888 requires electric utilities under FERC's jurisdiction to open their transmission lines to wholesale competition and to offer third parties the same or similar access to its transmission system that it offers itself. Since Order 888 was issued, FERC has continued to move to more competitive markets, issuing orders that build upon it and incrementally clarify it.

On June 17, 2010, FERC issued a 138-page NOPR, Docket No. RM10-23-000,[157] to amend transmission planning and cost allocation requirements associated with previous FERC orders. The purpose of this NOPR is to:

- Incorporate in transmission planning processes public policy requirements established by state or federal laws or regulations that may drive transmission needs.
- Provide transmission project sponsors the right, consistent with state or local laws or regulations, to construct and own facilities selected for inclusion in regional transmission plans.
- Improve coordination in the evaluation of transmission facilities proposed to be located in two neighboring transmission planning regions.
- Provide a closer connection between transmission planning and cost allocation processes.

With respect to transmission planning processes, the proposed rule would:

- Require each public utility transmission provider to participate in a regional transmission planning process that produces a regional transmission plan, according to pre-established principles.
- Require that local or regional transmission planning processes account for public policy requirements established by state or federal laws or regulations.
- Remove from FERC-approved tariffs or agreements any right of first refusal that provides an incumbent public utility with an undue advantage over a non-incumbent transmission project developer, while preserving state authority.
- Require each transmission provider, through its regional transmission planning process, to develop a regional planning agreement with transmission providers in each neighboring region.

With respect to transmission cost allocation, the proposed rule would:

- Establish principles for allocating the costs of new transmission facilities in a manner that is commensurate with the distribution of benefits.
- Require each transmission provider to have a cost allocation method for new transmission facilities in the regional transmission plan that satisfies certain proposed cost allocation principles.
- Require each transmission provider to have a cost allocation method for new transmission facilities resulting from the planning agreements implemented by neighboring regions that satisfies certain proposed cost allocation principles.

A perspective on the NOPR was offered by FERC Commissioner Marc Spitzer when the NOPR was issued: "Two questions arise again and again: who should plan for the new transmission and who should pay for the transmission facilities. I am now convinced that, until these questions are answered in a fair and reasonable manner, necessary transmission will not be built.... I see today's proposal as a necessary step to eliminating uncertainty that has impeded the development of transmission.... The NOPR does not advocate a uniform approach nationwide; it allows for regional differences in planning and cost allocation.... [The] NOPR proposes to remove from any FERC-approved tariff or agreement those provisions that give a right of first refusal to the incumbent utility. But I stress that FERC is not proposing to preempt any state or local law or regulation that establishes a right of first refusal. All that FERC is proposing is that no FERC-approved tariff or agreement be the source of undue discrimination."[158]

Perspective by WIRES (Working Group for Investment in Reliable and Economic electric Systems),[159] a coalition of utilities, environmental, renewables, and other groups.

WIRES urged the FERC to: "…take important steps now to establish targeted improvements in regional transmission planning and cost allocation practices and institutions across regions and markets, in order to stem continued uncertainty, interregional disputes, and protracted and expensive procedures that thwart basic changes in the energy economy. In these respects, WIRES contends that the Commission should employ this rulemaking proceeding to structure transmission planning processes, especially where they must address major interregional transmission facilities that integrate whole regions, to ensure that costs are allocated "roughly commensurate" with the range and distribution of benefits provided to customers, irrespective of whether a project physically crosses regional or market boundaries. Because the interstate transmission system is currently planned and governed by organizations with differing geography, operating systems, stakeholder groups, and interests, utilizing differing planning procedures, timelines, and criteria, WIRES urges the Commission to take additional steps to ensure the timeliness and coordination of planning procedures among all regions. For that reason, it supports requiring all proposed facilities to be evaluated under credible, coordinated regional planning processes."[160]

Western Stakeholder Perspectives

A summary review of comments to the NOPR from certain key stakeholders in the west was prepared by Duane Braunagel, Staff, Transmission Advisor, PUC. Mr. Braunagel's review includes some, but not all, of the comments to the NOPR filed with the FERC by certain entities in the west.

Western Electricity Coordinating Council

The WECC planning process does not request or select specific projects to be built, nor does it address cost allocation. WECC's Transmission Expansion Planning Policy Committee (TEPPC) identifies possible future transmission congestion and associated solutions. This information then is used by entities and decision makers in their planning processes. WECC supports the requirement that all transmission providers participate in the planning process. WECC also supports the requirement that established laws should be included in the planning process. [161]

WestConnect

WestConnect does not see the need for the NOPR. Existing transmission planning processes used in WestConnect are sufficiently robust to identify and evaluate needed solutions at all regional and subregional levels. FERC should support the collaborative efforts already in place. If the NOPR proceeds, it will take resources away from the current planning efforts. At a minimum, FERC should defer the NOPR until entities have had the opportunity to complete the first cycle of planning efforts under Order 890. WestConnect states that existing planning processes take into account "many" regional public policy requirements and efforts that should be relied upon by FERC to standardize major regional policy goals. WestConnect supports a basic cost allocation principle: those entities that use the transmission system should pay for it. WestConnect does not support centralized cost allocation methods, nor does it want any more regulations in this area.[162] The CCPG is a member of WestConnect, so it may be assumed that WestConnect's position reflects the views of the CCPG.

California Independent System Operator

CAISO is the only operating ISO in the WECC region. The ISO presents its case in a 97-page document. In summary, CAISO believes there is no legal basis for many of the reforms. CAISO also believes there is no record evidence that justifies these sweeping requirements, evidenced by the fact that the NOPR points to no studies of transmission projects that were rejected in existing planning processes that provided net economic benefits or reliability to customers. Further, the ISO is concerned that the proposed requirements in the NOPR will undermine effective planning processes.[163]

Xcel Energy

Xcel's comments urge the FERC to allow the Order 890 reforms to work before proceeding with the current NOPR. To the extent that FERC determines further action is needed, it should focus on incremental changes. Xcel argues that the right-of-first-refusal provisions should remain unchanged. They contend there is no evidence that needed transmission is not being built, except where cost-allocation or state jurisdictional issues have temporarily delayed construction. Xcel states that the right to build transmission in its service territory is a right granted to the incumbent provider in exchange for the incumbent's assumption of the obligation to serve.

Xcel's comments state that two major obstacles exist to developing a regional cost allocation scheme in the West. The most serious is the absence of centralized regional markets. These markets provide price signals illustrating where transmission facilities are needed and an opportunity for all market participants to benefit from transmission expansion projects that decrease the region-wide costs of delivered energy. The second is the absence of an identified entity to assume responsibility for making decisions about which projects will go forward. The voluntary nature and technical focus of planning organizations within the WECC may not make them the best candidates to assume this responsibility. Because cost allocation still occurs within the framework of individual utilities and state regulators make the decisions about what costs are recoverable by a utility, it is especially important for FERC to engage state regulators in this process. Regional cost allocation structures will be slow to emerge, absent prescriptive action by FERC.

In the West, each utility will participate in a project based on its perceived economic benefit. This process should continue. Over time, the need for commitment to a centralized cost allocation scheme may emerge.

One objective of state certification processes is to ensure that, regardless of the initial driver for the project (reliability, economics, or public policy), projects are ultimately scoped and sized to provide multiple benefits. Therefore, a cost allocation method should concentrate on identifying and measuring the types of benefits that transmission facilities provide, rather than on developing a new cost allocation method for each initial project driver.

Xcel believes that cost allocation proposals could be sped up by involving public policy leaders, particularly state regulatory agencies, as successfully demonstrated in recent cost allocation proposals within the Southwest Power Pool (SPP) and the Midwest ISO (MISO). Imposition of cost allocation methods by FERC upon a region would make transmission development more problematic, especially for state-regulated utilities and the public utility commissions (PUCs) that regulate them. A leadership role by regulators can help immensely in moving forward with development of a regional cost allocation mechanism.

Public policy requirements already are included in the planning process. Favorable sites for renewable resources, forecasted loads, and effects of energy efficiency, demand response, and peak load-shaving programs are reflected in the planning assumptions.[164]

Tri-State Generation and Transmission Association and Basin Electric

According to a joint filing by Tri-State and Basin Electric, FERC has not made the case that anything needs to be fixed. If there is a problem, it should be addressed case-by-case. Theoretical opportunities for discrimination should not be the basis for industry-wide change in transmission planning and cost allocation. Tri-State and Basin Electric acknowledge that the right of first refusal should be retained. The entities also suggest that FERC lacks jurisdiction to directly require REAs to participate in planning and cost allocation as contemplated in the NOPR. Moreover, the reciprocity requirements that have been used in the past to force REAs to have comparable tariffs are insufficient under this NOPR. [165]

Some of these transmission risks have been mitigated in Colorado because SB07-100 clarified the definition of "need."[166] That law authorized the PUC to approve a method for IOUs to receive expedited cost recovery for construction of transmission facilities. The law states: "The commission shall approve current recovery by the utility through the annual rate adjustment clause of the utility's weighted average cost of capital, including its most recently authorized rate of return on equity, on the total balance of construction work in progress related to such transmission facilities as of the end of the immediately preceding year. The rate adjustment clause shall be reduced to the extent that the prudently incurred costs being recovered through the adjustment clause have been included in the public utility's base rates as a result of the commission's final order in a rate case." This results in an incentive to the IOU, which no longer needs to wait for the outcome of a rate case to obtain cost recovery for transmission facilities. PSCo customers, for example, are providing current cost recovery through transmission cost adjustment (TCA) riders on their monthly electric bills to pay for recent utility expenditures to build transmission. For example, a resident's monthly bill for use of 715 kWh would include a $0.05 TCA.

As noted above, the ALJ in Tri-State's and PSCo's applications for CPCNs to construct the San Luis Valley transmission line granted the certificates but placed a condition on the PSCo certificate requiring it to refund half of the funds collected from ratepayers, including any authorized return, for construction of the line if a total of 700 MW of generation is not interconnected with the line within ten years of its in-service date. As a result and in spite of the statutory provisions noted above, cost recovery remains a significant issue for IOUs.

On December 18, 2010 the Pueblo Chieftain reported that "Xcel Energy is threatening to drop altogether a proposed power transmission line from Pueblo to the San Luis Valley. The utility – currently seeking to delay the project until 2016 at the earliest –opposes a proposed PUC condition on the Southern Colorado Transmission Line project. In a filing with the PUC, Xcel called the condition 'unreasonable and arbitrary' and argued the requirement flew in the face of commission rules and state law. The condition was proposed by a PUC Administrative Law Judge in a recommended. Tri-State supported Xcel's stance on the condition, but acknowledged it would have to re-evaluate how to proceed. 'Clearly, if Xcel Energy were to drop out of the proposed joint project because of this condition, Tri-State's needs would not justify continuing to pursue the same project as what is proposed,' spokesman Brad Jones said in an e-mail. If the proposal makes it through the utilities commission, it would still face a federal environmental review and approval from each of the four counties in the line's path.'

Insights on the FERC NOPR on Cost Allocation and Planning

Peter Behr, writing for the *New York Times*, reported on Nov. 12, 2010, that "FERC Moves Ahead With Campaign to Promote Energy Efficiency and Renewable Energy." Behr's article contains insightful quotations from FERC Chairman Jon Wellinghoff, who presented at a smart grid conference, "…pressing his campaign to pay consumers who conserve electricity equally with companies that generate it, and to promote transmission projects that serve wind and solar power." "Quite frankly, FERC is sort of operating independently of the electoral process," Wellinghoff said in an interview in Portland. "We've been acting under our statutory federal authority to move forward toward what I see as our responsibilities under the Federal Power Act, and that is to ensure rates are just and reasonable. And part of that I see as improving efficiency and competition in the markets, and incorporating new resources into the markets, including renewables and the demand side. That's been my strategic plan. That's been my focus, and I plan to continue that focus regardless of the change in Congress unless and until Congress would change our authorization legislation, and of course I would have to follow whatever Congress set out as policy."

Behr characterizes the FERC NOPR on transmission cost allocation and planning as requiring "…state renewable energy generation mandates to be a factor in approving new high-voltage transmission projects, giving them equal footing with reliability and economic factors. It would declare as policy that the largest transmission lines benefit wide geographic areas and interests, and thus their costs can be widely spread. The proposal would also strip away transmission line owners' current 'right of first refusal' when new transmission lines are called for in their territories. The current privilege may be unfair to independent transmission owners, notably those hoping to build lines to new wind power farms, according to FERC's proposal. This plan triggered protest from utility transmission owners, which

> The return of a strong federal role in national transmission infrastructure development should be actively pursued by Colorado policy-makers.

say FERC ignores the utilities' obligation to serve their customers. Regional interests want the rule modified in their favor. And Atlanta-based Southern Co. has made a frontal attack, contending that FERC has no authority to impose its transmission planning policy on the Southeastern region, where state-regulated power companies produce and deliver electricity."

Behr reported Wellinghoff predicts that: "FERC's staff can finish its report to the commission on demand response early next year, with commission action to follow. The transmission case will take more time—more than 18,000 pages of argument were filed in the initial comment period. So that proposed ruling probably won't go to the commission before spring. Just from talking to a number of companies, the right of first refusal is a very contentious issue, but to a limited number of companies. For example, Southern Co.—a huge, multi-state company—they have no problem with taking away the right of first refusal, because they don't have a right of first refusal right now in their tariff. A lot of companies [in] the Midwest are forming transmission subsidies to do transmissions in other utilities' jurisdictions, and they have no problem with it, either. It seems to me there are selective companies in certain areas that may have some concern … but I don't think it's a united front. We certainly are in a transition phase, and right now, the wholesale demand response market has the upper hand. I don't want to speak for the rest of the commission. Other commissioners are on the record expressing some concerns [about the demand response proposal]. So we'll see where we come out at the end of the day. I think we've made every effort to get as diverse views on the record as possible, so with that divergence of views, we're able to exercise pretty broad discretion as to where we move with respect to a particular rulemaking. As long as we have views that express multiple sides of the issues—and I think we certainly do in both these NOPRs—it's going to allow us to go pretty much either way, I believe. We can go pretty far. We are, I think, going quite far with the demand response compensation NOPR with the transmission planning and cost allocation NOPR."

Conclusion

Cost recovery and cost allocation issues will remain important topics at both the federal and state levels. The question will persist from a cost-benefit perspective on who should pay for regional and interstate transmission expansion.

At the time of this publication, FERC's NOPR has not yet been promulgated as an order. Anticipation of the new FERC order creates a new level of expectation and uncertainty in discussions regarding transmission and cost allocation policy. Should the FERC issue an order approximate to that proposed in the NOPR, compliance would incrementally move the United States closer to the goals of increased renewable integration with the commensurate benefits of carbon reduction and other environmental goals. At the same time, the new rule would represent a challenge to certain transmission providers that may prefer to proceed at their own pace with a minimum of what they may perceive as FERC interference.

Colorado policy-makers should encourage both the FERC and the PUC to exercise their pivotal roles to minimize uncertainties that may be inhibiting the right-sizing of transmission lines that are directly traceable to the cost allocation and cost recovery issues. The return of a strong federal role in national transmission infrastructure development should be actively pursued by Colorado policy-makers.

9. Federal Action and Inaction

REDI Review

"A national RES would provide a major signal to the market that the nation is prepared to pursue a course of sustainable, orderly development for renewable energy. Should a national RES become the law of the land, this key policy development would provide greater market confidence to spur increased investment in renewable energy technologies and projects. "

" FERC oversees and approves rates for interstate transmission and has a "backstop" role in siting certain new transmission lines. A few general themes of FERC's efforts in transmission policy include:

- Open, coordinated, and transparent planning
- The need for infrastructure, especially with regard to renewable energy development
- Comparable treatment of distributed generation and energy efficiency
- Elimination of barriers to entry of merchant and other nontraditional utility investment "

Overview

During the past 30 years, considerable federal effort has been made to develop and introduce legislation aimed at building a national energy policy. The stated objectives of these congressional and federal regulatory activities are to improve the security and availability of the nation's energy supplies; enhance the efficiency and sustainability of energy use; facilitate development and commercialization of clean, renewable energy technologies; reduce the environmental and health impacts associated with energy use; strengthen and modernize the nation's energy infrastructure; reduce the cost of energy; and create an engine for economic growth through domestic high-tech job creation and technology export.[167]

Until such time that the vast congressional energy and environmental legislative agenda is resolved or clarified, industry and government policymakers will be left with varying degrees of uncertainty about how—and whether—to make strategic decisions. Perhaps at the top of the key unresolved initiatives that cause this uncertainty are the prospects for a national or international approach to reduce greenhouse gases (GHGs) and a national RPS. Other issues are apparent, such as the ever-increasing importation of petroleum in the face of the peaking of world petroleum production, and the introduction of electric vehicles in the marketplace. In addition, legislation appears to be under constant debate; it includes enacting more stringent environmental standards to protect public health and America's natural heritage, and deciding whether to provide large loan guarantees to nuclear power plants and clean coal projects. Several recent bills include provisions for modernizing the transmission grid via incentives and policies to accelerate the transmission siting and approval process. Because this report focuses on electric power and transmission, several relevant pieces of legislation being debated or under consideration are summarized below.

American Clean Energy and Security Act (H.R. 2454)

On June 26, 2009, the House of Representatives passed the American Clean Energy and Security Act (ACES) by a vote of 219-212.[168] The act, also commonly referred to as the Waxman-Markey Bill, was introduced by Energy and Commerce Committee

Chairman Henry A. Waxman (D-CA), and Subcommittee Chairman Edward J. Markey (D-MA). The legislation was intended to be a comprehensive approach to America's energy policy. It received varying levels of support from electric utilities; energy companies; manufacturing, industry, and labor unions; and community and environmental organizations, and is generally regarded as the reference point for most expectations of what both houses of Congress might eventually pass. Key provisions of ACES include the following.

- Requiring electric utilities to meet 20 percent of their electricity supply from renewable energy sources and energy efficiency by 2020. This would constitute a national RPS. Colorado's RES exceeds this and would not be rolled back by a national standard.
- Investing in new clean energy technologies and energy efficiency, including energy efficiency and renewable energy ($90 billion in new investments by 2025), carbon capture

and sequestration ($60 billion), electric and other advanced technology vehicles ($20 billion), and basic scientific research and development ($20 billion).

- Establishing new energy-saving standards for new buildings and appliances.
- Reducing CO_2 emissions from major U.S. sources by 17 percent by 2020, and by a minimum of 80 percent by 2050 compared to 2005 levels.
- Protecting customers from energy price increases.

ACES contains four titles: 1) Clean Energy, 2) Energy Efficiency, 3) Reducing Global Warming Pollution, and 4) Transitioning to a Clean Energy Economy. Among the Clean Energy provisions, two titles directly affect transmission planning and development.

- **Renewable Energy Standard** ACES would require retail electric suppliers to meet a growing percentage of their load with electricity generated from renewable resources and electricity savings. The combined renewable electricity and electricity savings requirement begins at 6 percent in 2012 and gradually rises to 20 percent in 2020. At least three-quarters (75 percent) of the requirement must be met by renewable energy, except that, upon receiving a petition from a state governor, the FERC can reduce the renewable requirement to three-fifths (60 percent). In 2020, 15 percent of the electricity load in each state must be met with renewable electricity, and 5 percent with electricity savings. Upon petition by the governor, the renewable requirement could be reduced to 12 percent, and the electricity savings could be increased to 8 percent. The legislation also would require the federal government to meet 20 percent of its energy needs with renewable energy by 2020.
- **Modernizing the Electricity Grid** ACES includes provisions to promote deployment of smart grid technology and transmission planning and siting. The transmission provisions include federal backstop siting authority in the Western Interconnection for transmission lines needed to meet demand for renewable energy.

Among the Reducing Global Warming Pollution provisions, one indirectly affects transmission planning and development.

- **Capping CO_2 Emissions From Large Sources** Beginning in 2012, ACES would establish annual tonnage limits on emissions of CO_2 and other global warming pollutants from large U.S. sources such as electric utilities and oil refineries. Under these limits, carbon pollution from large sources must be reduced by 17 percent below 2005 levels by 2020, and by 83 percent below 2005 levels by 2050. To achieve these limits, ACES would establish a system of tradable permits called "emission allowances," modeled after the successful Clean Air Act program to prevent acid rain. This market-based approach provides economic incentives for the industry to reduce CO_2 emissions at the lowest cost to the economy.

ACES was introduced in the Senate and placed on its calendar in early July 2009. After a year of failed efforts to garner bipartisan support, Senate Majority Leader Harry Reid (D-NV) shelved the legislation in July 2010, acknowledging insufficient backing for its passage. Parallel to these proceedings, and in its place, Senator Reid and other members of Congress have introduced more limited proposals, leaving ACES stalled with an indefinite future.

Other Legislation under Discussion

Given the proponents' inability to muster sufficient support for ACES, several bills[169] —more limited in scope—have been introduced by members of both houses of Congress. These cover a broad range of energy topics, and, in many cases, are related, duplicative, and/or overlapping. Below is a list of those bills containing provisions likely to either directly or indirectly affect transmission planning and development.

Renewable Electricity Promotion Act of 2010 (S. 3813)

Introduced by Senator Jeff Bingaman (D-NM) on Sept. 21, 2010

- The proposed legislation would amend Title VI of the Public Utility Regulatory Policies Act of 1978 to install an RPS requiring states to generate at least 15 percent of their electricity from renewable sources by 2021. The standard would start at 3 percent in 2012, increasing by 3 percent in 2014, 2017, 2019, and 2021, respectively.

- Federal Renewable Energy and Energy Efficiency Credit Trading Programs would be established as a means of compliance for utilities.

- Qualifying generation technologies under the bill are wind, solar, ocean, geothermal, biomass, landfill gas, waste-to-energy, hydrokinetic, and new hydropower at existing dams.

- Thirty-six states currently have some form of renewable portfolio standard, alternative energy portfolio standard, or renewable energy goal. States that lack renewable energy plans are Alabama, Alaska, Arkansas, Georgia, Idaho, Indiana, Kentucky, Louisiana, Mississippi, Nebraska, Oklahoma, South Carolina, Tennessee, and Wyoming.

Practical Energy and Climate Plan Act (PECPA) (S. 3464)

Introduced by Senator Richard Lugar (R-IN) on June 9, 2010

- This proposed legislation aims to make meaningful progress on energy-driven national security, economic, and environmental concerns. It differs from most of the other energy-climate bills in that it seeks to reduce GHG emissions by reducing oil imports, improving and creating new efficiency standards, and establishing a clean energy standard. There is no cap on greenhouse gases or a price on carbon.

- However, section 302 in Title III, Diverse Domestic Power, instructs the administrator of the EPA and the secretary of energy to establish an incentive program to permanently retire conventional coal plants that have the largest pollution-related liabilities. Any electric generating unit that voluntarily enters into a binding retirement agreement with the administrator to permanently retire the unit not later than Dec. 31, 2018, would be eligible for regulatory relief through an array of items.

American Power Act (APA) (Discussion Draft)

Released by Senators John Kerry (D-MA) and Joe Lieberman (I-CT) May 12, 2010

- This comprehensive climate change and energy independence legislation[170] was released to the Senate for its consideration, but has not been formally introduced. The Senate version of ACES was still under consideration when APA was proposed.

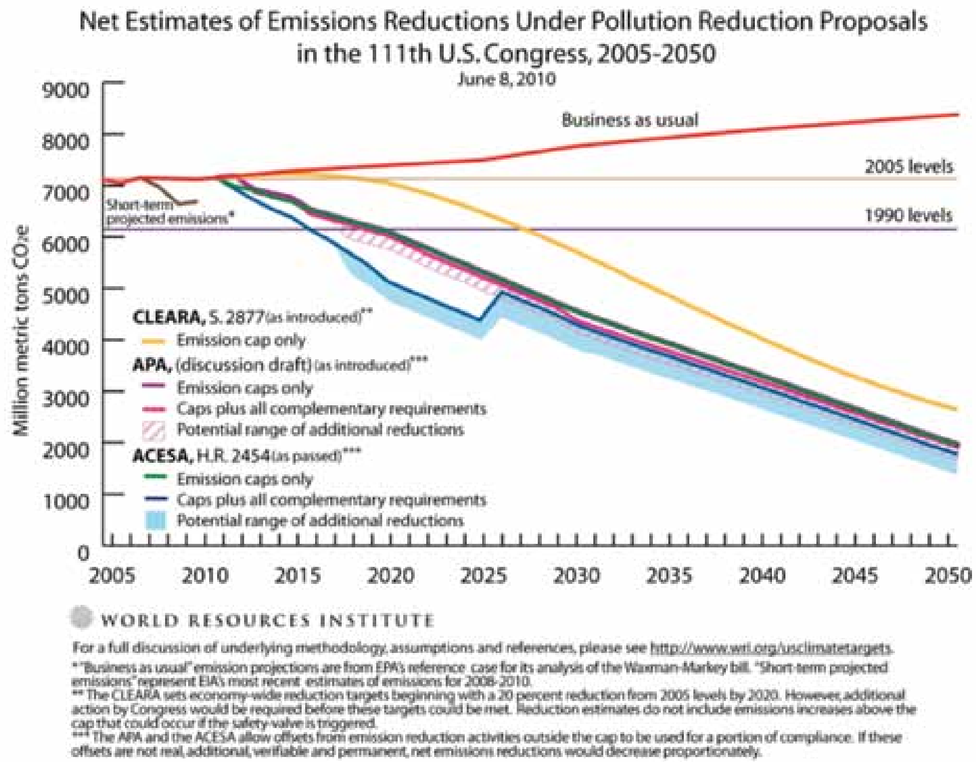


Figure 81: Net Estimates of Emissions Reductions under Pollution Reduction Proposals in the 11th Congress, 2005–2050

Source: World Resources Institute [171]

- APA encourages domestic nuclear power generation; initiates a national strategy and deployment for carbon capture and sequestration; amends the Clean Air Act to establish stricter GHG emissions standards for new coal-fired power plants; provides for potential financial and regulatory incentives to accelerate the transition of existing coal-fueled power plants to significantly cleaner generation; amends the Clean Air Act to reduce global warming pollution by establishing a cap and trade program; and defines specific jurisdiction over, and regulation of, greenhouse gas markets.

- On June 14, 2010, the EPA released its economic analysis of the bill, comparing and contrasting APA with ACES. EPA's analysis concluded that, "... while there are important differences between the American Power Act (APA) and H.R. 2454...the modeled impacts of the APA are very similar to those of H.R. 2454."

On the previous page, figure 81 illustrates net estimates of emissions reductions under current proposals before Congress.

Other bills recently introduced and/or with less momentum warrants attention and are presented in the table below.[172] The Congressional proposals presented above provide detailed information primarily on 2009 and 2010 actions. The Nov. 2, 2010 election changed the makeup of Congress, and much has been written about possible implications for climate change legislation in the next few years. The *New York Times* reported on Nov. 4, 2010, that, "...during a White House press conference on November 3, President Obama said that policymakers must not ignore global warming science, but he declined to give an endorsement of upcoming EPA greenhouse-gas rules. The president called for bipartisan cooperation on energy policy. He said he's open to several ideas on climate instead of cap-and-trade legislation that he acknowledged won't move in coming years. The greenhouse gas issue remains front-and-center because EPA is moving ahead to limit emissions under its existing powers. President Obama also affirmed EPA's right to act, citing the landmark 2007 Supreme Court ruling that paved the way for the agency to regulate greenhouse gases under the Clean Air Act.' The EPA is under a court order that says greenhouse gases are a pollutant that falls under their jurisdiction. One of the things that is very important for me is not to have us ignore the science, but rather to find ways that we can solve these problems that don't hurt the economy, that encourage the development of clean energy in this country, that in fact may give us opportunities to create entire new industries and create jobs and that put us in a competitive posture around the world,' Obama said."

Name	Bill No.	Sponsor	Introduced
Advanced Energy Tax Incentives Act of 2010	S. 3935	Jeff Bingaman (D-NM)	9/29/10
Promoting Natural Gas and Electric Vehicles Act of 2010	S. 3815	Harry Reid (D-NV)	9/21/10
Clean Energy Jobs & Oil Company Accountability Act of 2010	S. 3663	Harry Reid (D-NV)	7/28/10
Promoting Electric Vehicles Act of 2010	S. 3495	Byron Dorgan (D-ND)	6/15/10
Electric [Drive] Vehicle Deployment Act of 2010	S. 3511 H.R. 5442 S. 3442	Byron Dorgan (D-ND Edward Markey (D-MA)) Byron Dorgan (D-ND)	6/18/10 5/27/10 5/27/10
Carbon Limits & Energy for America's Renewal (CLEAR) Act	S. 2877	Maria Cantwell (D-WA)	12/11/09
American Clean Energy Leadership Act of 2009 (ACELA)	S. 1462	Jeff Bingaman (D-NM)	7/16/09

Alaska Senator Murkowski has called on the EPA to take regulations off the table. Her office issued the following statement: "There are a great number of things we can do to responsibly reduce our carbon emissions without burdening our economy with an unworkable cap-and-trade scheme or command-and-control regulation by the EPA. Many of those policies, including investment

in renewable and alternative energy technology, increased efficiency, and expanding our nuclear power options were included in the comprehensive bill I helped pass out of the Energy Committee more than a year ago. If the president wants to start with the work the Energy Committee has already done, I would be happy to work with him. But I also believe we must first preempt the EPA from meddling in the work of Congress when it comes to setting climate policies. Murkowski has made several previous attempts at blocking EPA regulations. Her last one failed in June, but it had the support of six Democrats. Significant Republican gains in the Senate certainly increase the possibility that a similar block could pass this year, though Obama would likely veto it."

In a related matter, the U.S. Supreme Court announced in December 2010 that it will hear a climate change nuisance suit brought against four electric utilities (including Xcel Energy) and the Tennessee Valley Authority alleging that greenhouse gas emissions from their power plants are a public nuisance under common law. According to the New York Times, "The case, brought by Connecticut and seven other states, the city of New York and a trio of land trusts, has been wending its way through lower courts since 2004. It was seen as a third avenue to addressing climate change, the other two being federal regulations and legislation.

Last year, the US Court of Appeals for the Second Circuit allowed the case to go forward, reversing a lower court's decision that it centered on a "political question." The ruling also rejected the defendants' arguments that Environmental Protection Agency (EPA) regulations of greenhouse gas emissions under the Clean Air Act would override a common law nuisance complaint. The Obama Administration has also said it believes the nuisance suits would interfere with the EPA effort. In their appeal to the Supreme Court, the defendant utilities – American Electric Power, Southern Company, Xcel Energy and Cinergy (now part of Duke Energy) – raise questions of whether and under what laws states and private parties can seek to place emissions caps on utilities, and whether such laws exist or must be made, which would be beyond the scope of the judicial system. The plaintiffs seek court-ordered injunctions on carbon emissions and economic damages caused by climate change. Oral arguments before the Supreme Court are expected in spring. A decision, which could be delivered in June, would be the most important environmental ruling in the U.S. since the high court decided that greenhouse gasses do constitute a pollutant under the Clean Air Act, clearing the way for EPA regulation.

Pressure on the Electric Power Sector to Increase Environmental Performance

The EEI has produced a summary chart of the wide variety of environmental regulations affecting generation—and particularly coal generation—in the next few years. Figure 82. The chart conveys the range of regulations and rulings that affect the electricity sector and illustrates the difficulty of planning toward what many believe is an uncertain future.

The need to address environmental and public health problems historically has encountered resistance. It is especially true today. A recent, report indicates that climate change litigation tripled in 2010. Without federal legislation regulating GHG emissions, litigation is on the rise

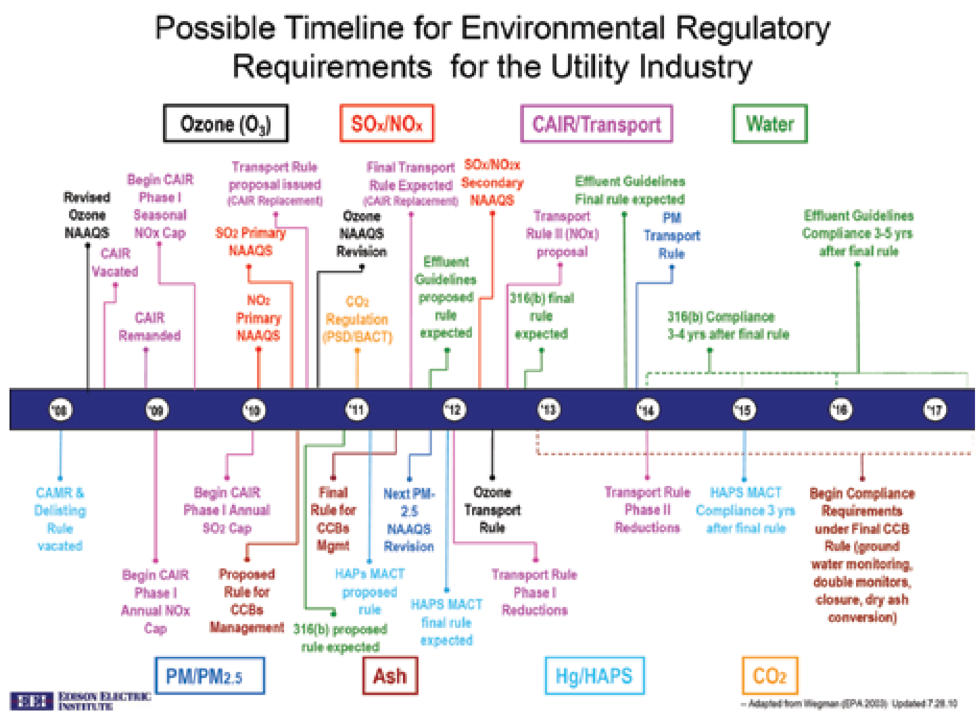


Figure 82: Possible Timeline for Environmental Regulatory Requirements for the Utility Industry

Source: Edison Electric Institute[173]

in the United States. The number of climate change lawsuit filings doubled between 2006 and 2007, and is set to triple 2009 levels this year, according to a report from an arm of Deutche Bank, DB Climate Change Advisors (DBCCA). The November 2010 report, *Growth of US Climate Change Litigation: Trends & Consequences*[174] finds "… that the largest increase in litigation has been challenges to federal action, specifically industry challenges to proposed EPA efforts to regulate greenhouse gas emissions, according to researchers. From 2001 to date, 24 percent of total climate change-related cases were filed by environmental groups aiming to prevent or restrict the permitting of coal-fired power plants, with about 37 states joining, or stating their intent to join, either side of the litigation. DBCCA expects the number of climate change-related court cases to continue growing for the foreseeable future. Industry groups are specifically targeting three Obama-era U.S. Environmental Protection Agency regulations: the December 2009 finding that greenhouses cases endanger human

What FERC Regulates	What FERC Does Not Regulate
Economic • Electric transmission and wholesale sales of electricity in interstate commerce • Accounting and financial reporting of regulated companies	Economic • Retail electricity sales to customers • Regulation of municipal power systems, federal power marketing agencies (such as the Tennessee Valley Authority), and most rural electric cooperatives
Infrastructure • Licensing and inspection of private, municipal, and state hydropower projects • Overseeing environmental matters related to hydropower projects and major electricity policy initiatives • Interstate natural gas pipelines	Infrastructure • Approval to construct electric generation, transmission, or distribution facilities, except hydropower • Nuclear power plant regulation • Electric transmission siting

health and welfare, fuel efficiency standards for cars and light trucks, and rules to curb emissions by factories and power plants. The Chamber of Commerce, the National Association of Manufacturers, the American Iron and Steel Institute and the American Chemistry Council, and others have filed multiple lawsuits in the U.S. Court of Appeals for the District of Columbia. In August 2010, the U.S. Chamber of Commerce filed a lawsuit that challenges EPA's 2009 endangerment finding, which is the foundation for the agency's ruling on limiting emissions from power plants, factories and other heavy emitters. In February, several industry groups, conservative think tanks, lawmakers, and three states filed 16 court challenges against EPA's endangerment finding."

FERC and EPA Roles

FERC and the EPA have significant authority with respect to regulating and overseeing domestic energy markets. Through congressional legislation and executive orders, these institutions have embarked on various initiatives that could substantially influence the future of the electricity sector and, therefore, the future of transmission planning and development.

Federal Energy Regulatory Commission

As an independent agency, FERC[175] regulates the interstate transmission of electricity. Its jurisdiction covers both economic and infrastructure regulation. See the above chart. It is appropriate to clarify what FERC does and does not regulate—with respect to electricity—to create a baseline of understanding for this discussion. See the above chart.

On Sept. 20, 2010, FERC issued Order No. 739, Docket No. RM10-22-000, Promoting a Competitive Market for Capacity Reassignment. This order makes electricity markets more efficient by permanently lifting the price cap for all reassignments of firm transmission capacity by wholesale electric transmission customers. As part of the open access transmission policies in Order No. 888, FERC required transmission providers to amend their Open Access Transmission Tariffs (OATT) explicitly to permit voluntary reassignment of all or part of a holder's firm point-to-point capacity rights to any eligible customer, subject to a price cap. Interim studies and reports since Order No. 888 found that reassignment prices comported with pricing differentials between those markets, indicating that resale prices reflect market fundamentals rather than the exercise of market power.

FERC has demonstrated by word and action that it is committed to encouraging prudent transmission development. The commission has established rules to bolster investment in the nation's transmission infrastructure and to promote electric power reliability and lower costs for customers by reducing transmission congestion. The Energy Policy Act of 2005 directed FERC to develop incentive-based rate treatments for transmission of electric energy in interstate commerce, adding a new section (Section 219) to the Federal Power Act. The rule implemented this new statutory directive through a wide range of incentive-based rate treatments.

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. The rule also provides expedited procedures for approval of incentives to provide utilities greater regulatory certainty and facilitate project financing. The rule became effective Sept. 29, 2006.

On Nov. 18, 2010, the FERC proposed reforms to make the U.S. electric grid more accessible to electricity generated by renewable energy sources, which should lower costs for consumers who want to buy clean power. The FERC proposed a rule requiring public utility transmission providers to allow renewable power producers to schedule their shipments of electricity over shorter time periods to better reflect the moment-to-moment changes in generation output by renewables. Wind and solar power producers would be able to schedule transmission service in 15-minute intervals, instead of the current one-hour scheduling procedure.

FERC Chairman Jon Wellinghoff said, "Most of the new power plants for which developers are seeking access to the grid are variable resources such as wind and solar generators. This proposal will help the commission to cost-effectively integrate these and other variable generators into the grid in a way that helps maintain reliability and operational stability. The proposal is intended to help meet the Obama administration's goal to double the amount of U.S. electricity generated by renewable energy sources. The U.S auto and transportation industries are moving toward electric vehicles that will create new demand for power, and making it easier to for electricity producers to get on the grid will help meet that demand."

Following the release of the NOPR, AWEA stated the FERC may have made an unintentional error. AWEA interprets the current wording of the proposed rules as requiring wind farm operators pay for their own integration costs and also for fossil fuel plants that have forced outages. AWEA's concerns will be sent in formal comments to the FERC.

Environmental Protection Agency

The EPA's mission[176] is straightforward: To protect human health and to safeguard the natural environment—air, water, and land—upon which life depends. How it achieves its mission, and what falls within its jurisdiction, however, are less straightforward.

As referenced above, Congress has approached the challenge of global climate change through a variety of legislative efforts aimed at reducing and/or capping the domestic production of greenhouse gases. Although many in Congress intend to address the challenge, a number of forces (most notably corporate lobbying and partisan-based) prevented Congress from successfully passing comprehensive energy legislation. Partially as a response to congressional failure to produce legislation, on Oct. 5, 2009, President Obama signed Executive Order 13514, "Federal Leadership in Environmental, Energy, and Economic Performance." This order introduced new GHG emissions management requirements; expanded water reduction requirements for federal agencies; and addressed waste diversion, local planning, sustainable buildings, environmental management, and electronics stewardship. In addition, it enhances Executive Order 13423, which required federal agencies to reduce energy and water intensity and achieve other sustainability goals.

Shortly thereafter, on Dec. 7, 2009, EPA Administrator Lisa P. Jackson signed two distinct findings regarding greenhouse gases under section 202(a) of the Clean Air Act:

- **Endangerment Finding:** The administrator found that the current and projected concentrations of the six key well-mixed greenhouse gases— CO_2, methane (CH4), nitrous oxide (N2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF6)—in the atmosphere threaten the public health and welfare of current and future generations.
- **Cause or Contribute Finding:** The administrator found that the combined emissions of these well-mixed greenhouse gases from new motor vehicles and new motor vehicle engines contribute to the greenhouse gas pollution that threatens public health and welfare.

On Dec. 15, 2009, final findings were published in the *Federal Register* under Docket ID No. EPA-HQ-OAR-2009-0171. The final rule became effective Jan. 14, 2010. On the day of the signing, the EPA administrator said: "These long-overdue findings cement 2009's place in history as the year when the United States Government began addressing the challenge of greenhouse-gas pollution and seizing the opportunity of clean-energy reform. Business leaders, security experts, government officials, concerned citizens and the United States Supreme Court have called for enduring, pragmatic solutions to reduce the greenhouse gas pollution that is causing climate change. This continues our work towards clean energy reform that will cut GHGs and reduce the dependence on foreign oil that threatens our national security and our economy."[177]

The EPA's findings respond to the 2007 U.S. Supreme Court decision that GHGs fit within the Clean Air Act definition of air pollutants. The endangerment finding means that the EPA can set stronger emissions requirements in the future, guided by these findings in conjunction with the Supreme Court interpretation of the Clean Air Act.

On Feb. 19, 2010, eight U.S. lawmakers sent EPA Administrator Jackson a letter expressing strong concern that EPA regulations would adversely affect their coal-producing states. The letter commented, "The President and you have been explicit in calling on Congress to pass comprehensive legislation that would enhance our nation's energy and climate security. We strongly believe this is ultimately Congress' responsibility."[178]

In the spring of 2010, the EPA finalized the GHG Tailoring Rule, which specifies that, beginning in 2011, projects that will increase GHG emissions substantially will require an air permit. The Tailoring Rule covers large industrial facilities such as power plants and oil refineries that are responsible for 70 percent of the GHGs from stationary sources. On Aug. 12, 2010, the EPA proposed two new rules to ensure that businesses that plan to build new, large facilities or make major expansions to existing ones would be able to obtain Clean Air Act permits that address their GHG emissions.

On Oct. 7, 2010, the EPA issued a draft of its fiscal year 2011–2015 strategic plan, which provided a blueprint for advancing its mission and Administrator Jackson's priorities. The five-year plan includes new benchmarks that track progress against Jackson's seven priorities, including taking action to reduce emissions of greenhouse gases and adapting to climate change.

On December 23, 2010 the EPA announced that it would regulate GHG emissions from power plants and oil refineries next year. The move, which comes as part of a legal settlement with several states, local governments and environmental groups which have sued EPA under the Bush administration for failing to act, highlights the Obama administration's intent to press ahead with curbs on carbon despite congressional resistance. Under the agreement, EPA will propose new performance standards for power plants in July 2011 and for refineries in December 2011 and will issue final standards in May 2012 and November 2012, respectively. Following this announcement, Xcel Energy stated that the company is well-positioned to meet new standards for greenhouse gas pollution. The company has switched several of its coal-fired plants to natural gas already, the company said it will continue to ratchet down its pollution: "Our goal, company-wide, is to reduce by 15 percent our carbon emissions by 2020, and we're well on our way to doing that."

On December 17, 2010 Congress passed a federal tax bill that contains a one-year extension of federal tax grants for alternative energy projects. Act 1603 was set to expire at the end of the year but was revived through its inclusion in President Obama's tax bill. At least $25 billion in renewable energy projects in the U.S. could benefit from a decision by Congress to extend a Department of Treasury grant program. The Treasury program provides an early infusion of cash to renewable energy projects in lieu of production and investment tax credits they might otherwise receive over years. The grants can cover up to 30% of the costs of installing solar, wind and other alternative energy projects.

Effects of Uncertainty Created by Potential Different Scenarios of Federal Directions

National and international concerns about global climate change will continue to place pressure on policymakers to reduce CO_2 emissions and other GHGs. As discussed, several approaches to control CO_2 emissions have been proposed, and each results in a different potential price range for carbon.

In one analysis, completed by McKinsey & Co., a policy-agnostic carbon abatement supply curve was developed, resulting in carbon costs ranging from -$90 per ton to $50 per ton (see Figure 83).[179] Negative marginal costs indicate that investing in these options would generate positive economic returns over their lifecycle.

Despite wide and uncertain carbon price ranges, utilities and other service providers must continue to develop resource plans to ensure adequate resources for their customers. Lacking concrete regulations, utilities often model a wide range of scenarios in order to understand the effects these uncertain futures might have on their resource strategy. In a recent analysis of utility resource plans conducted by the Lawrence Berkeley Laboratory, eight of 15 western utilities modeled scenarios across a broad range of carbon prices (Figure 84).[180] The distribution of potential carbon prices used by the various utilities indicates the degree of uncertainty resource planning strategies face under stalled congressional activity.

This uncertainty is directly felt in the transmission planning community

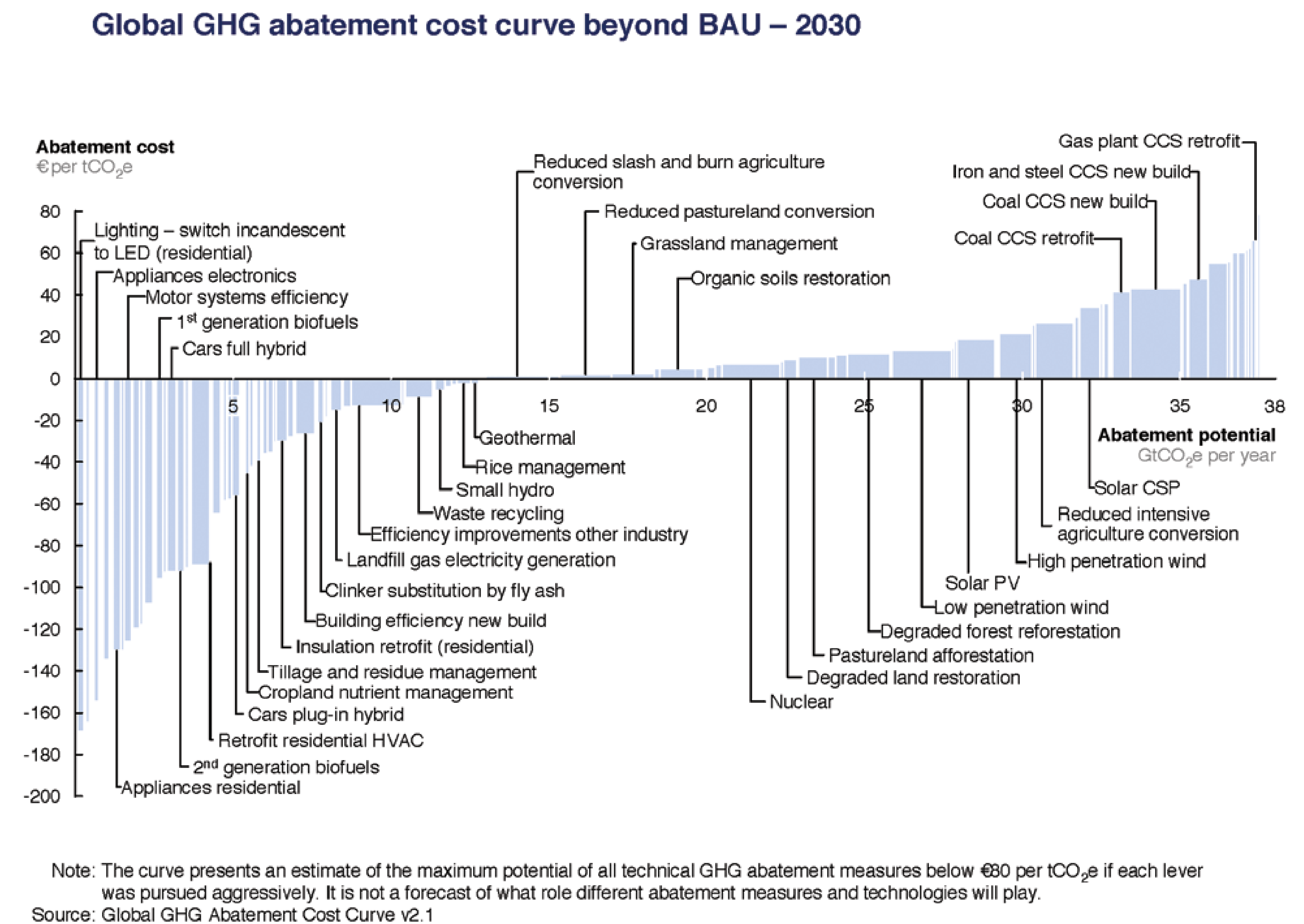


Figure 83: McKinsey Mid-Range CO_2 Abatement Curve

Source: McKinsey & Co.[181]

Uncertainty is directly felt in the transmission planning community because the potential effect of carbon prices is a major factor in determining which generation projects will be built and where the transmission will be needed to support them.

because the potential effect of carbon prices is a major factor in determining which generation projects will be built and where the transmission will be needed to support them. In addition, most generation or transmission projects in the planning stage are less likely to be financed until this uncertainty is resolved. The effects of the current credit crisis and recession further exacerbate the uncertainty.

Conclusion

Many states, including Colorado, have stepped in to fill the federal policy gap by implementing their own environmental and energy policies. Although this provides greater clarity in a particular state, the interdependency of the electric markets among neighboring states means regional solutions cannot be predicated on assessing the aggregate collection of individual state actions.

Within the industry, the effects of this legislative uncertainty are clearly evident. EEI[182] states: "A single Federal statue should fully replace all Federal and state regulations. As Congress considers legislation to reduce the nation's CO_2 and other GHG emissions, it is essential to harmonize state and federal policies to avoid multiple, overlapping GHG regulatory regimes… Only a single federal statute designed with the unique characteristics of GHGs in mind—rather than overlapping, duplicative, and potentially conflicting regulations—can provide the certainty needed for businesses to reduce GHG emissions effectively as well as the flexibility needed to help mitigate the economic impacts on customers. The economy and businesses are at risk when states, federal agencies, and Congress create a patchwork of overlapping, duplicative, and potentially conflicting regulations. This approach creates enormous uncertainty and threatens effective emissions reductions. Instead, a single federal statute—to replace all other federal and state statutes—will provide a clear path to a low-carbon future with the certainty and flexibility needed to protect the environment and consumers."

Colorado executive and regulatory leadership should expand its existing interaction with the Western Governors' Association's initiatives and other entities to ensure that federal executive, congressional, and agency leaders develop timely and effective state-federal policy frameworks to create a dynamic, clean, efficient, and renewable 21st century electricity sector.

Levelized CO_2 Emission Prices Used in Utility Resource Plans (2010-2030)

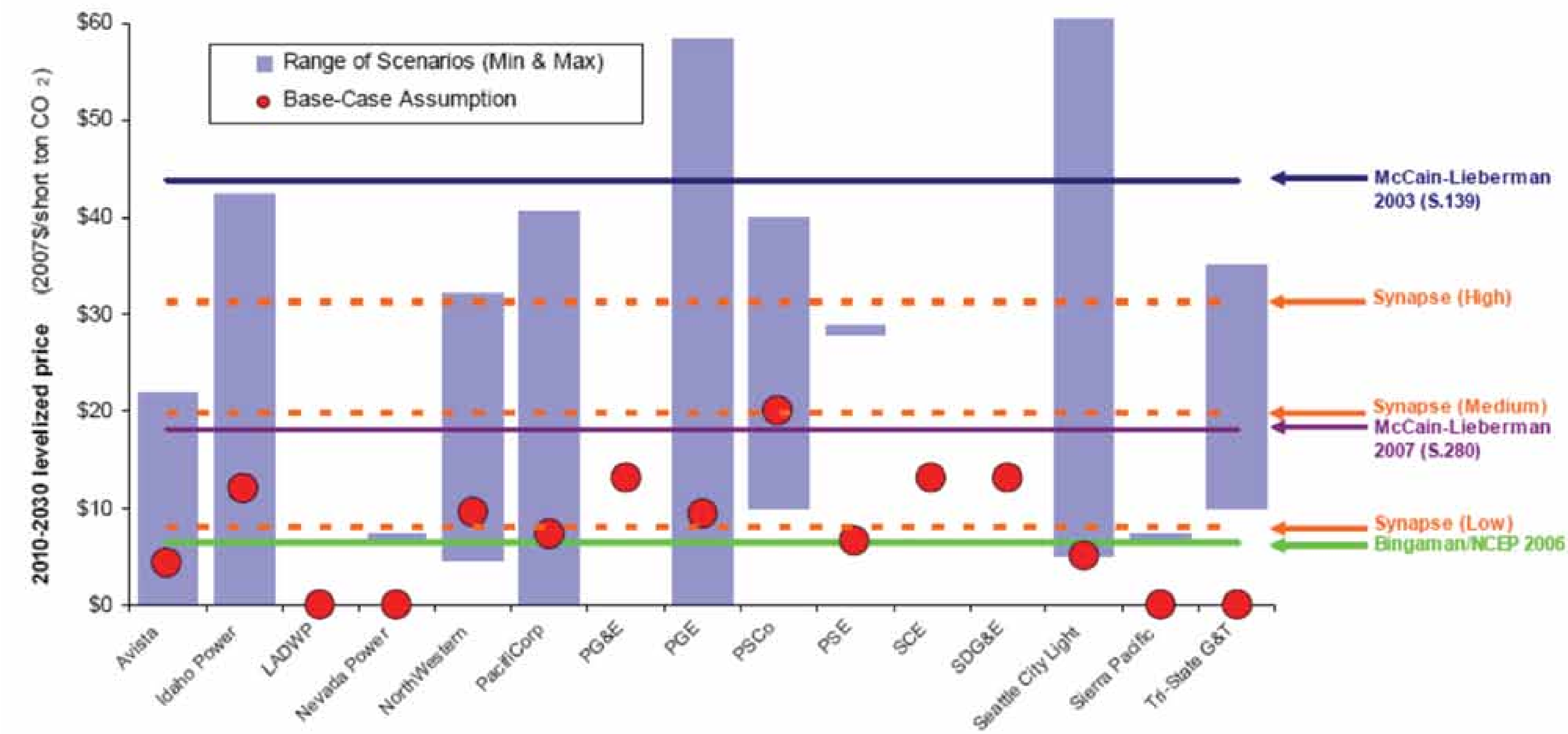


Figure 84: Levelized CO_2 Emission Prices Used in Utility Resource Plans (2010-2030)

Source: Lawrence Berkeley National Laboratory[183]

10. Regional Planning Activities

REDI Review

" Transmission is a connector. Colorado possesses vast wind and solar resources. These resources will serve society when that energy is delivered from remote resource areas by high-voltage transmission to loads (the places where homes, businesses, or others use electric power) through their serving substations and lower-voltage distribution systems. It is widely understood in Colorado that the existing transmission infrastructure that serves most of the GDAs identified in the SB07-91 report are insufficient to deliver high levels of new, clean generation from renewable resource-rich rural areas to the markets, mostly along the Front Range. Progress is being made by industry groups, nongovernmental organizations, and others to remedy these insufficiencies through work at the PUC, in regional planning venues, in the legislature, and elsewhere. However, both bidding for new and occasionally for operation of existing renewable energy facilities is constrained by insufficient transmission capacity.

Overview

The WECC defines transmission planning as "the discipline that evaluates the current configuration of the electric transmission grid in an area or region, compares it to expected changes, and evaluates options to "fill in the gaps" between current and future needs. The current configuration includes factors like equipment currently in place (transmission lines, substations, transformers, etc.), current generating resources (e.g. natural gas plants, wind farms, etc.), and existing electricity demands. Changes to the grid could include constructing new transmission lines, constructing new generating resources, increasing or decreasing electricity demand, and programs like energy efficiency and management of electricity demand that could affect the need for and use of electricity."

Figure 85 illustrates the North American Electric Reliability Corporation Interconnections.

One important trend in the electricity sector that both Congress—through the American Recovery and Reinvestment Act—and the FERC—through its planning requirements—have aggressively encouraged is to involve a wider community of stakeholders in transmission planning. In Colorado's region, two of the most important entities involved with regional planning are the Western Governors' Association (WGA) and the Western Electricity Coordinating Council (WECC). These entities are the umbrella groups through which much of the political and technical coordination occurs. Figure 86 illustrates WECC historical and projected electrical capacity and energy.

Western Governors' Association

The WGA is an independent, nonpartisan organization of governors representing 19 western states and three U.S. Pacific islands. Through their association, governors identify and address key policy and governance issues concerning natural resources, the environment, human services, economic development, international relations, and public management. The governors state there is broad agreement that a significant increase in the use of renewable energy is dependent upon expansion of

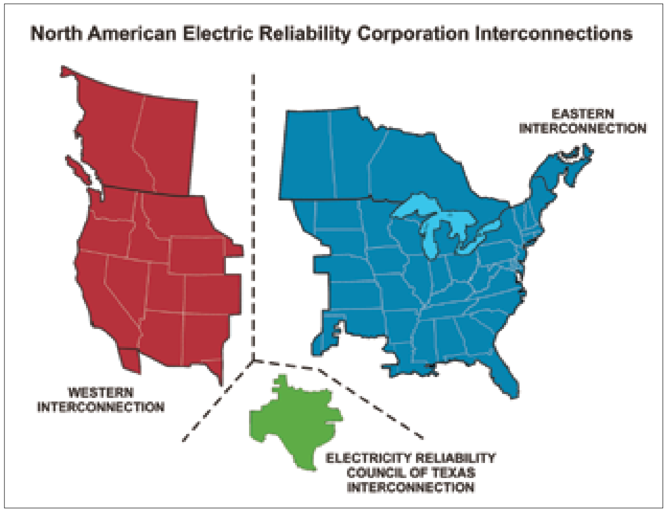


Figure 85: NERC Interconnections[184]

Source: DOE

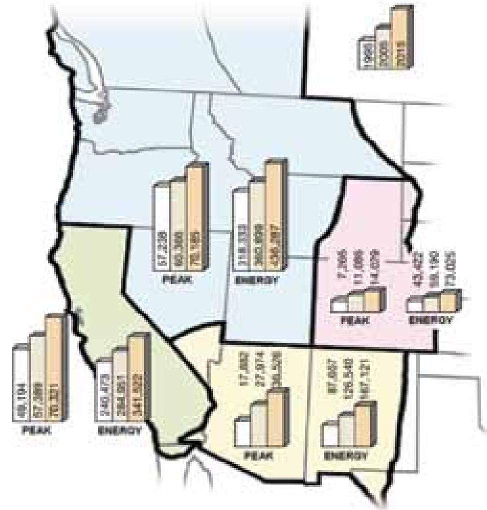


Figure 86: WECC Historical and Projected Electrical Capacity and Energy

Source: WECC[185]

WGA has focused on some key next steps: determining which of the high-quality areas are of greatest interest to electric service providers, determining how their renewable resources can best be developed, and planning for a transmission network that will bring those resources to market.

the existing transmission grid. The publication of the June 2009 WGA and DOE Western Renewable Energy Zones (WREZ) Phase 1 report provided a view of where the richest, most commercially viable renewable resources are within the Western Interconnection. This was an important first step toward expanding renewable energy development. Since the publication of the WREZ report, WGA has focused on some key next steps: determining which of the high-quality areas are of greatest interest to electric service providers, determining how their renewable resources can best be developed, and planning for a transmission network that will bring those resources to market.

In June 2009, the DOE announced the availability of stimulus money to analyze transmission requirements under a broad range of alternative energy futures and to develop long-term, interconnection-wide transmission expansion plans. In December 2009, DOE announced a combined total of $26.5 million would be given to the WGA and the Western Electricity Coordinating Council to complete this work. WGA and its energy arm, the Western Interstate Energy Board, are concentrating efforts in two major areas: continuation of activities initiated under the WREZ project, and development of alternative energy futures that can be modeled into transmission plans that will open high-quality renewable resource areas.

The WGA states: "An exciting element of the transmission planning process is that, for the first time, wildlife and water resources will be incorporated into the modeling analyses. Part of the DOE funding will go to states for development of decision support systems that can be used to help assess the viability of new energy generation and transmission in certain areas. Funding also will be devoted to examining the regional impacts of new energy generation on water use, including a look at the potential effects of long-term drought on energy production. The wildlife and water information will be critical to the transmission modeling and will increase the potential viability of any transmission plan."[186]

The WGA coordinates a wide variety of projects, focusing on issues related to the West. The Regional Transmission Expansion Project (RTEP), funded by the DOE, is a significant undertaking and will greatly improve regional ability to plan for new transmission.

Regional Transmission Expansion Project

Governors and public utility commissioners within the Western Interconnection share the goal of having a clean, secure, reliable, and reasonably priced electricity generation and transmission system. Reaching these goals will require greater development and use of renewable energy resources and expansion of the existing transmission grid.

The WGA, Western Interstate Energy Board, and WECC are working with diverse stakeholders through the RTEP to analyze transmission requirements under a broad range of alternative energy futures and to develop long-term, interconnection-wide transmission expansion plans.

As part of the overall project, various future electricity generation and transmission scenarios are developed to show the effects each would have on the economies, natural resources, and landscapes in the West. The information will assist investors who have "due diligence" financial information requirements to justify their investment decisions; state policymakers such as legislators who may need to change state laws; regulators responsible for economic regulation of utility firms and for facility siting, water, and wildlife; the federal government; generation and transmission developers; load-serving entities; and the public, including nongovernmental organizations, to develop and promote policies and incentives that will achieve the governors' energy goals. Similar transmission planning efforts are under way in each of the other two interconnections, the East and Texas.

The RTEP builds upon stakeholder recommendations made as part of the WREZ initiative.[187] WGA and the DOE launched the WREZ initiative in 2008, and a Phase 1 report that included a map of high-quality, developable renewable resource areas was completed in 2009.[188] RTEP is focused on transmission planning that provides information to support project development and policy and project decisions. It expands transmission planning activities that WECC has managed through its Transmission Expansion Planning Policy Committee (TEPPC) for many years and will create ten-year transmission plans in 2011 and 2013, and a 20-year transmission plan in 2013. A specific goal of the RTEP project is increased involvement of nonprofit organizations and advocacy groups that have not traditionally been involved in transmission planning in the Western Interconnection. The regional transmission plans produced through the RTEP project will support:

- Public and private decision making about investments and approvals for new transmission lines
- Increased coordination among entities in the Western Interconnection
- Increased awareness of how energy policy decisions affect transmission reliability and cost
- Ability to answer key policy questions at state, provincial, and federal levels
- Additional information for use by decision makers in siting and cost allocation proceedings

Western Electricity Coordinating Council

The Western Interconnection includes all or part of 14 U.S. states, two Canadian provinces, and a portion of Baja California Norte, Mexico. The WECC is governed by a stakeholder board consisting of 32 directors drawn from the 253 WECC members in seven membership classes.

WECC members, recognizing the need for a regional approach to transmission expansion planning, organized the Transmission Expansion Policy Planning Committee (TEPPC) to provide transmission expansion planning coordination and leadership across the Western Interconnection. TEPPC works in close coordination with subregional planning groups, transmission operators, and others to facilitate regional economic transmission expansion planning. The functions performed by TEPPC complement, but do not replace, the responsibilities of WECC members and stakeholders regarding planning and development of specific projects.

Transmission Planning at the WECC

Transmission planning evaluates the current configuration of the electric transmission grid in an area or region, compares it to expected changes, and evaluates options to fill the gaps between current and future needs. The current configuration includes factors such as existing equipment (transmission lines, substations, transformers, etc.), generating resources (natural gas

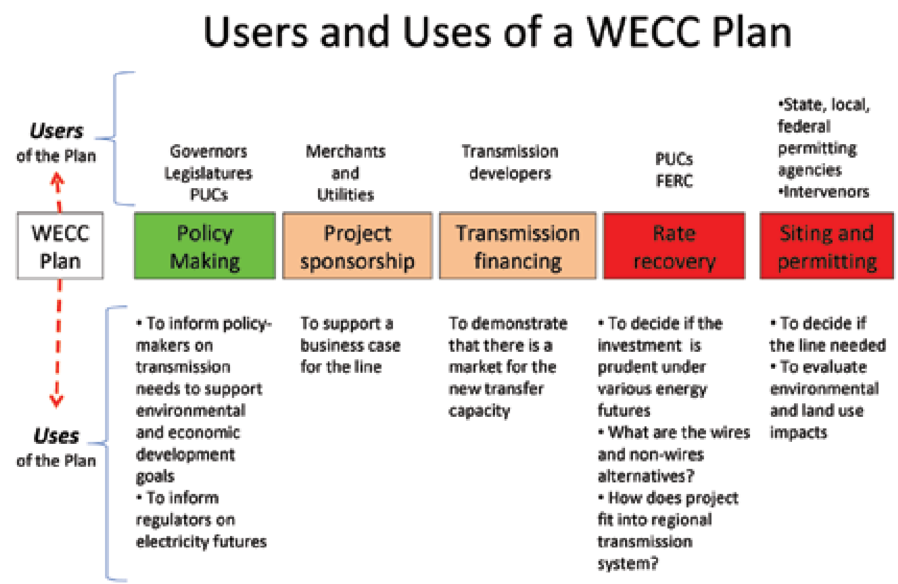


Figure 87: Users and Uses of a WECC Plan

plants, wind farms, etc.), and electricity demands. Changes to the grid could include more efficient use of existing transmission, rebuilding and upgrading existing transmission facilities with new technologies and control systems, constructing new transmission lines, establishing new generating resources, increasing or decreasing electricity demand, and developing programs such as energy efficiency and management of electricity demand that could affect the need for and use of electricity (Figure 87).

Transmission planning differs from project development. Planning defines the broad requirements for necessary transmission capacity without specifying how capacity needs will be met. Project development proposes a solution to the needs identified through planning, which then must undergo financial "due diligence" reviews to justify investment, path rating (to determine the reliability impacts of the proposed project on the transmission system), siting (to determine the effects of the proposed project on the environment and other

WECC is responsible for regional transmission planning, and the WGA conducts regional transmission planning policy and resource assessments in the Western Interconnection.

land uses), approval of the "need" for a project sponsored by a regulated utility, cost allocation (to account for the division of joint costs of production), and cost recovery (to determine who will pay for the proposed project and to ensure cash flow to support project development).

WECC is responsible for regional transmission planning, and the WGA conducts regional transmission planning policy and resource assessments in the Western Interconnection.

Most of WECC's transmissions planning activities are managed through its TEPPC, which has a defined annual process for receiving and analyzing transmission needs. TEPPC coordinates a three-tiered planning process that includes TEPPC, subregional planning groups (SPGs), and the transmission providers (Figure 88).

Scenario Planning Steering Group

The Scenario Planning Steering Group (SPSG), a 25-member stakeholder-led group, was created by WECC to guide the RTEP project. The SPSG includes diverse stakeholder representation (states and provinces; utilities; nongovernmental organizations; technology advocates for wind, solar, and geothermal energy development; and consumer advocates) to advise WECC's TEPPC.

The SPSG will fulfill many responsibilities for the RTEP project, including:

- Recommending to TEPPC load and resource scenarios (potential future electricity demands and types and locations of electric generating resources) that should be evaluated in detail to contribute to the ten--year and 20-year transmission plans.
- Reviewing TEPPC's annual study program and the activities of TEPPC's subcommittees and work groups to align the SPSG's activities with those of other TEPPC groups.
- Communicating with the constituencies its members represent to facilitate broad understanding of and participation in the RTEP project.
- Reaching out to new groups that may have a stake in the results of transmission planning activities in the Western Interconnection.
- Recommending priorities for spending funds made available by the Department of Energy to support the RTEP project from 2010 through 2013.

State-Provincial Steering Committee

The State-Provincial Steering Committee (SPSC), created by WGA, is composed of state energy offices and state public utility commissions from the western states to add their participation in WECC's RTEP project. They have contracted with DOE for funding to conduct transmission planning efforts; analyze and recommend region-wide actions to minimize the cost of integrating large amounts of renewable energy into the grid; and analyze and recommend policies to improve grid efficiency.

The WECC and WGA coordinate their respective roles on the RTEP through frequent staff contact and liaisons between the SPSG and the SPSC. Eight state energy office and public utility commission stakeholders serve on both committees. Colorado's representatives to the SPSC are Colorado Public Utilities Commissioner Jim Tarpey and GEO Transmission Program Manager Morey Wolfson.

Transmission Expansion Planning Policy Committee

One important role for TEPPC is to provide governance over the RTEP project. Each year, TEPPC develops a study program that details the

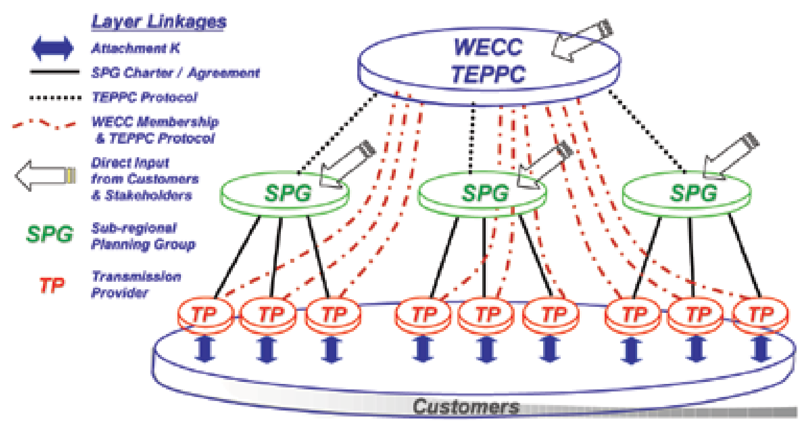


Figure 88: WECC Three-Tier Planning Process

Source: WECC[189]

transmission system expansion studies it will perform. The program is based on study requests received during the committee's open season request window (November 1–January 31). Any interested party can submit a study request to TEPPC for consideration. Analysis and studies performed by TEPPC focus on a few plans selected from among the many submitted with interconnection-wide implications and include a high-level assessment of transmission congestion

Figure 89: Subregional Planning Groups

Source: WestConnect[190]

and operational impacts. Results from TEPPC's studies are intended to provide insights into transmission expansion needs within the Western Interconnection. TEPPC uses models that rest on their assumptions, provide ten-year studies, and create outputs that are focused on WECC's reliability considerations. TEPPC modeling does not include detailed, project-specific studies; does not advocate for specific projects or identify potential "winners" and "losers;" and does not become involved with siting and cost allocation issues. TEPPC plans to acquire new models that will expand the scope of considerations that can be included and to add 20-year considerations in its modeling.

Subregional Planning Groups

The subregional planning groups (SPGs) (Figure 89) conduct more local, subregional transmission planning and include:

- California Independent Service Operator (CAISO)
- Sierra Sub-regional Planning Group (SSPG)
- Southwest Area Transmission (SWAT)
- Colorado Coordinated Planning Group (CCPG)
- Northern Tier Transmission Group (NTTG)
- Columbia Grid
- BC Hydro representing British Columbia
- Alberta Electric System Operator (AESO)

The SPGs provide input to the subregional coordinating group (SCG), which is used to develop a list of projects.

Subregional Coordinating Group

The SCG was formed to facilitate the WECC's efforts to create interconnection-wide transmission plans for the Western Interconnection. The SCG meets quarterly and is composed of representatives from each TEPPC-recognized SPG and BC Hydro.

The primary purpose of the SCG is to develop the foundational transmission projects list for use in developing TEPPC's interconnection-wide plans. This list relies on input from the individual SPGs. The SCG also maintains a list of potential transmission projects— called the potential transmission projects list—that have been identified in SPG ten-year plans but do not yet meet the foundational transmission project criteria.,

The SCG foundational transmission project list is a subset of the projects currently in the SPG's ten-year plans that have a high probability of being built during the coming ten years. Foundational transmission projects also satisfy the following voltage-level criteria:

- Projects that are 500 kV and above
- Projects at 345 kV, unless they are deemed not to be a backbone facility
- Projects above 200 kV that are deemed to be backbone facilities

The purpose of the foundational transmission project list is to provide a basic set of transmission facilities that TEPPC can use as a starting point for its studies. TEPPC can add transmission facilities to mitigate congestion and integrate new resources for a broad set of future resource scenarios. The foundational transmission project list does not replace or impose changes on SPG transmission planning processes and plans. The projects included in the foundational transmission project list are shown in Figure 90 and Figure 91.

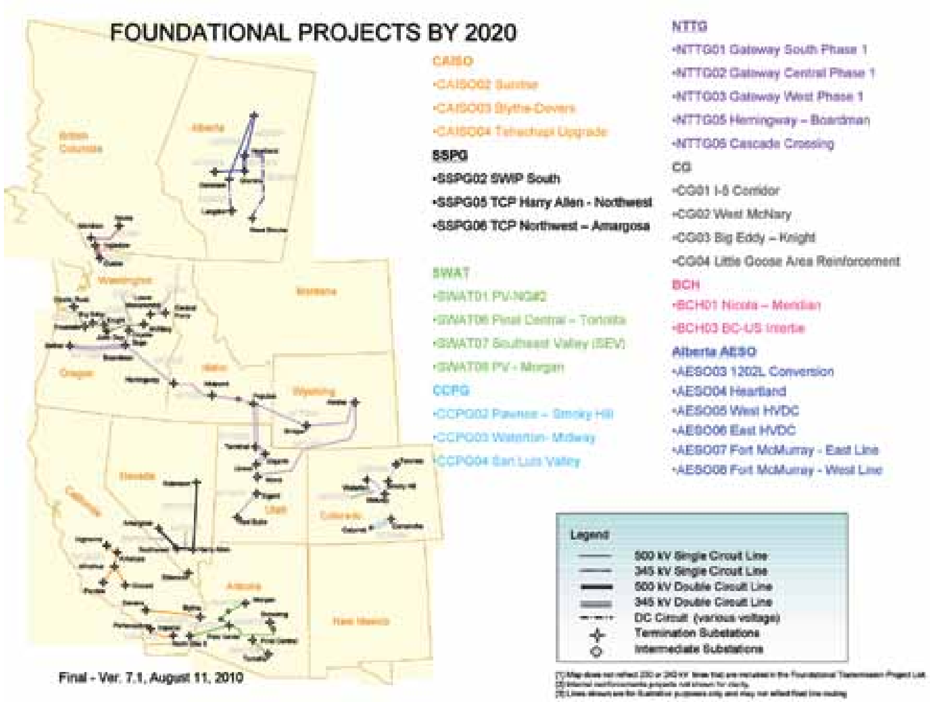


Figure 90: Foundational Projects by 2020

Source: WECC[191]

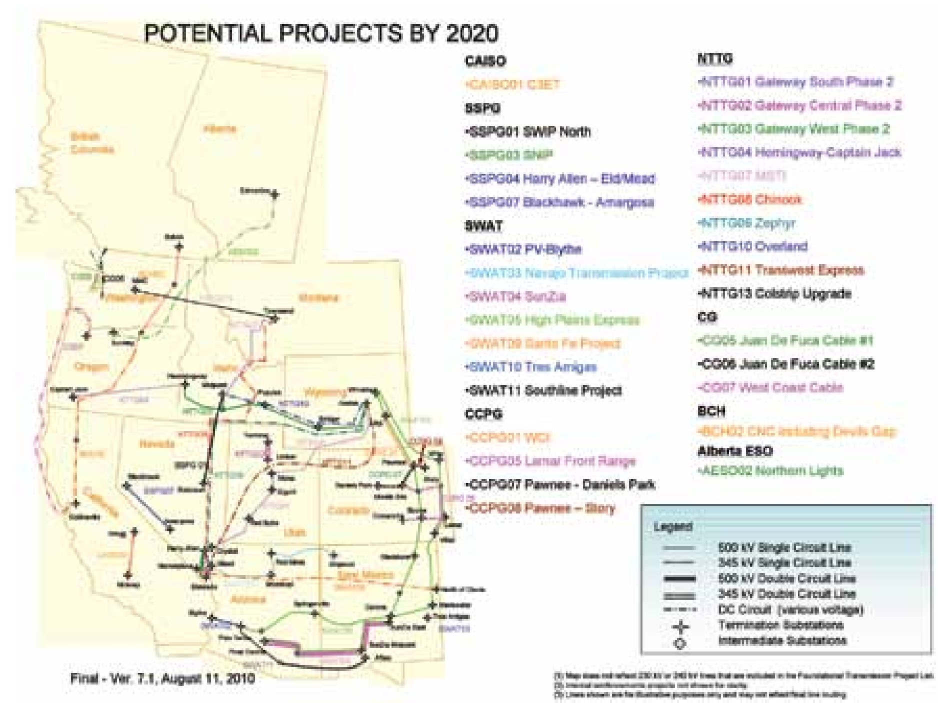


Figure 91: Potential Projects by 2020

Source: WECC[192]

The potential transmission projects list includes projects that have been identified in SPG ten-year plans but do not meet the foundational transmission project criteria, which are located on the WECC website. They are provided for TEPPC to use when selecting additional transmission facilities needed to develop the WECC interconnection-wide transmission plan. Information on these potential projects also is provided in the matrix of transmission projects. Figure 91 shows potential transmission projects.

Conclusion

Transmission planning is clearly evolving to incorporate a wider community of stakeholders that each have valid interests in how the transmission sector should be expanded. Much of this evolution has been encouraged by the FERC and the DOE, and, in general, utilities have embraced the opportunity to work with a wider audience of transmission stakeholders. The WGA and WECC are investing significant time and effort in developing committees and working groups to coordinate the wide range of perspectives on this issue. Most observers expect to see continued results in this area in the relatively near future.

Legislators and the PUC should expand their participation in regional planning activities to ensure that the state benefits from economic development, energy, and environmental quality opportunities that are directly related to these activities.

11. The Feasibility of Exporting Colorado's Renewable Energy

REDI Review

According to the REDI report, "WGA, with technical support from NREL, estimated Colorado's developable export-quality renewable energy potential to be 15.7 GW of wind power and 2.3 GW of solar power. The SB07-91 report supports these statistics, stating Colorado has more utility-scale renewable energy potential than it needs for domestic consumption, as is the case with most states in the WECC. There is no guarantee, however, that other states would necessarily elect to buy renewable power from Colorado. The greatest potential demand for significant amounts of renewable power is in the Southwest, including the Los Angeles Basin. However, other states may have a competitive advantage over Colorado as potential suppliers to that market, due in large part to their closer proximity to the loads."

NREL produced a 36-page technical report for GEO's REDI Project, *Colorado's Prospects for Interstate Commerce in Renewable Power*. The report concluded that Colorado could benefit from selling renewable power to other states, but doing so would likely require multistate policy partnerships. Interstate commerce in almost any commodity requires some conveyance infrastructure and common rules to ensure fair and open access to the market. Colorado cannot by itself plan or authorize the transmission that would be necessary for more robust interstate commerce in renewable power to occur. Even if Colorado were to try to accelerate its environmental and siting reviews, the issue remains whether the power could reach the market via the existing regional transmission network.

Overview

Colorado is rich in renewable resources. However, it is transmission-constrained and geographically remote from large loads that would purchase Colorado's renewable energy exports. Nearby states such as Wyoming hold additional renewable resources that could be imported into the state to help meet Colorado RPS requirements. Colorado's participation in an interstate transmission project is being reviewed to better understand the opportunities for import and export of nearby states' and Colorado's renewable resources.

Markets for Export

The largest markets for renewable energy purchases lie in the Southwest (Arizona and Nevada) and Southern California. These states have aggressive RPS goals—California's Executive Order at 33 percent by 2020; Arizona at 15 percent by 2025; and Nevada at 25 percent by 2025 (see Figure 92).[193] Accessing the Southwest and Southern California markets is of keen interest to certain renewable developers, certain utilities, and others, since these western states have large populations and, therefore, some of the largest renewable requirements markets.

Colorado's Transmission System

A determination of the feasibility of exporting Colorado's renewable energy to markets in the southwest, or elsewhere, requires a review of the opportunity for Colorado resources to use existing transmission systems to reach these markets. Colorado's transmission system is bound geographically on the central and west

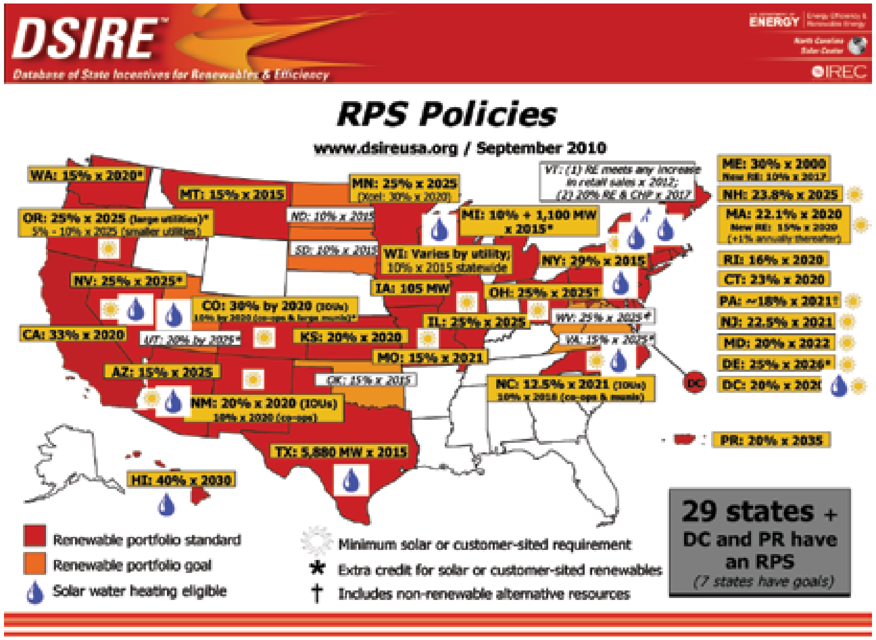


Figure 92: Renewable Portfolio Standard Policies by State

Source: Database of State Incentives for Renewables and Efficiency[193]

Other nearby western states also have rich solar and wind resources. Colorado is at a certain disadvantage compared to those states where transmission over fewer miles could supply the Southwest and Los Angeles Basin markets.

Figure 93: Colorado's Transmission Constraints

Source: Colorado Energy Forum[195]

sides by the Rocky Mountains. It is a daunting siting and cost challenge to build transmission in mountain terrain. The state is bound on the east by the utilities' limited capability to synchronously connect to the Eastern Interconnection. This limitation requires that all transfers of power between the eastern and western interconnections to use alternating-current/direct-current/alternating current (AC/DC/AC) convertor stations. The state is electrically constrained on the northern and southern borders by the utilities' limited transmission interconnections for bulk transfers of energy.

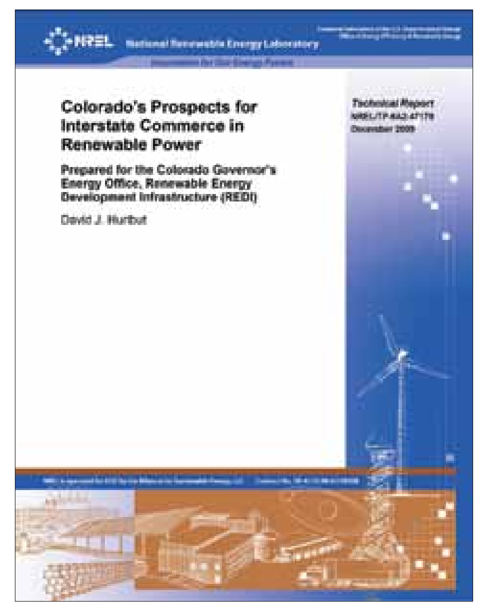
Transmission import and export capabilities within and outside Colorado have been constrained for many years. A combination of factors has led to this result. A primary reason for this condition is that over the past three decades, the new capacity has nearly exclusively gas-fired generation built close to load centers, negating the need for the long-distance transmission needed when the major capacity additions were coal and hydro. Transmission import and export capabilities are enumerated as TOTs (short for "total"), denoting the total electric transfer capability of a particular transmission corridor. (See Figure 93). These TOTs demonstrate the limited capabilities in all directions for potential opportunities to export Colorado's electric generation (whether renewable or thermal resources).[196]

Renewable Resources in Colorado and Nearby States

Although Colorado is very rich in renewable resources, other nearby western states also have rich solar and wind resources. Several have the advantage of being closer to the large load centers. As described in the REDI report, utility-scale solar resources in Arizona, California, and Nevada have the advantage of being closer to the major West Coast and Southwest loads. Solar resources, although more expensive than wind resources, have a higher capacity factor than wind. New Mexico's wind resources are comparable to Colorado's; its solar thermal resources are better than the bulk of Colorado's and are closer to the Southwest loads. Figures 94 and 95, produced by NREL and extracted from the REDI report, indicate how Colorado's wind and solar potential compare to resources in other western states.[197]

As shown in the graphs, Colorado's significant wind and solar resources are so substantial that the state will never need to import renewable energy due to a lack of them. However, Colorado is at a certain disadvantage compared to those states where transmission over fewer miles could supply the Southwest and Los Angeles Basin markets. The following information is discussed in detail in the 36-page NREL report, *Colorado's Prospects for Interstate Commerce in Renewable Power*,[198] commissioned by GEO's REDI Project.

- Wyoming has substantial wind resource potential that are rated higher than Colorado's (based on cost per unit of output). However, Wyoming's distance to markets is approximately the same or further than Colorado's, depending on the corridor.
- New Mexico's solar resource potential has higher direct normal insolation (DNI) factors than found in Colorado, and New Mexico's wind potential is comparable to Colorado's.


NREL National Renewable Energy Laboratory

Colorado's Prospects for Interstate Commerce in Renewable Power

Prepared for the Colorado Governor's Energy Office, Renewable Energy Development Infrastructure (REDI)

David J. Hurlbut

Technical Report

State Wind Potentials

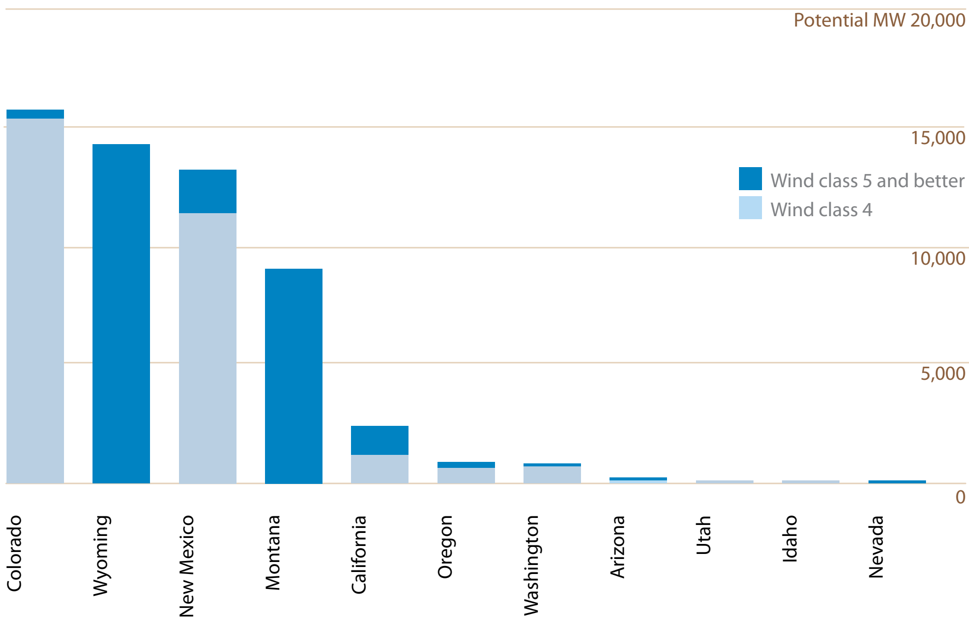
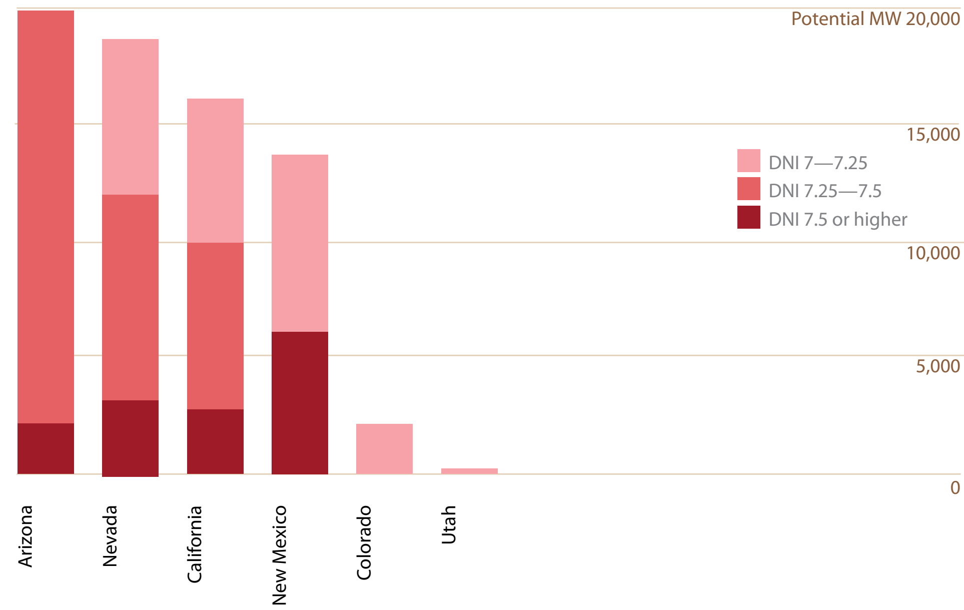


Figure 94: State Wind Potentials

Source: Colorado Governor's Energy Office, REDI report[199]

State Solar Potentials



Direct normal insolation (DNI) measures the amount and intensity of sunlight falling on a given ground point during a normal year. DNI is measured in kilowatts of sunlight per square meter per day.

Figure 95: State Solar Potentials

Source: Colorado Governor's Energy Office, REDI report [200]

- Although wind resources in California, Oregon, and Washington have a lower-rated capacity, they enjoy a competitive advantage because they are closer to that region's load centers. Lower transmission costs reduce the delivered cost per unit of output, compensating somewhat for generally lower wind speeds.[201]

It is interesting to note that a recent study from Arizona State University ranks Colorado as the nation's second-best state for companies interested in exporting solar power, after Arizona.

The study,[202] published in *The Electricity Journal*, was authored by Matthew Croucher, an assistant research professor at ASU's W. P. Carey School of Business. The study used statistics from various sources (including NREL) to establish a list of states that are best positioned to be solar energy exporters. After Arizona and Colorado, the report ranks Georgia, Texas, Hawaii, Arkansas, Wyoming, Alabama, Missouri and California as top solar-power exporters. The study also ranks Colorado third for consumption of solar power, after Hawaii and New Mexico.

Following Colorado on consumption are Missouri, Georgia, Texas, Arkansas, Alabama, Mississippi, Oklahoma and Wisconsin.

Proposed Renewable Energy Export Transmission Projects Involving Colorado

High Plains Express

The primary interstate bulk power transmission project currently under consideration for Colorado is the High Plains Express Transmission Project (HPX). HPX would access the wind-rich plains of eastern Colorado and, via secondary interconnections, the sun-filled areas of the San Luis Valley. It would then move the energy to markets in the southwestern U.S. [203] A second interstate bulk power project is envisioned to traverse a short section of the northwest corner of Colorado.

The High Plains Express Transmission Project [204] (HPX) is a proactive plan to expand and reinforce the transmission grid in Arizona, Colorado, New Mexico, and Wyoming. Eleven parties are

Single Corridor

HPX Path I- Wyoming-Colorado

Two Corridor

HPX Path I- Colorado-New Mexico-Arizona

Figures 96: Conceptual HPX Alternatives

Source: High Plains Express [205]

participating members of HPX: Black Hills Corporation, Colorado Clean Energy Development Authority, Colorado Springs Utilities, LS Power, New Mexico Renewable Energy Transmission Authority, NextEraEnergy Resources, Public Service Company of New Mexico, Salt River Project, Tri-State Generation and Transmission Association, Western Area Power Administration, Wyoming Infrastructure Authority, and Xcel Energy. The group holds regular meetings where the results of their studies are presented to interested parties.[206] The goal of HPX is to develop a high-voltage, backbone transmission system that will enhance reliability, increase access to renewable and other diverse generation resources, and open interstate markets for renewable generation within regional energy resource zones.

The first phase of the HPX was a joint feasibility study that was completed and reported in June 2008. On the basis of the analyses and the resulting report, several detailed second-phase feasibility studies (more detailed) and additional stakeholder outreach were completed. The second stage scenarios included a range of voltages and broad corridors. A variety of configurations have been analyzed, ranging from a single corridor to two corridors, with additional options (see Figures 96). HPX has also conducted economic feasibility studies and land use inventories. Depending upon the configuration under study, the price ranges from a low of approximately $4.5 billion for a single circuit 500 kV line, to a high of approximately $8.2 billion for a two corridor double circuit 500 kV line. The study also considered building the project in segments, i.e. Wyoming-Colorado, and Colorado-New Mexico-Arizona. The exact routes are yet to be determined. A third stage to further refine the previous assessments was initiated in December 2010.

The Prospects for Exporting Colorado's Renewable Power

As discussed, a conceptual export market opportunity may exist for Colorado renewable resources to the Southwest and Southern California. However, there are several challenges facing these conceptual plans. One primary challenge to obtaining access to these markets requires a buyer—that is, a power purchase agreement from a utility. Before large capital investments are made, the shippers on the line and the transmission project are seeking answers to questions regarding cost recovery and cost allocation.

Colorado is akin to an electric system island located on the eastern end of the Western Interconnection. Without an RTO, generators lack access to a liquid electric market.

WWSIS Study Discussion Regarding Long-Distance Transmission

NREL's *WWSIS* study contains important questions about whether new long-distance transmission is needed to the extent some may believe. The report suggests that new intrastate transmission or intra-area transmission is required for renewable energy generation to access load or bulk transmission lines. The report said that the in-area scenario (this scenario assumes each state within the study footprint meets its wind and solar energy penetration target using the best wind and solar resources within each state boundary), which included no additional long-distance, interstate transmission, operated as well as the other scenarios studied in the report. Up to 20 percent renewable penetration could be achieved with little or no new long-distance, interstate transmission additions, assuming full utilization of existing transmission capacity. The study concluded that 30 percent wind and 5 percent solar penetrations were feasible, but they would require key changes to current practices involving many factors. For local or interstate transmission, planning and reliability analyses (e.g., transient stability, voltage stability, protection and control, and intra–area constraints and challenges) need to be conducted in the WestConnect region.[207]

Factors Affecting the Potential for Exporting Renewable Power from Colorado

Several considerations are worth further investigation, based on information obtained to date.

- Colorado's abundant wind and solar resources are more than sufficient to meet the state's RES requirement of a minimum of 30 percent renewable energy by 2020.
- Colorado's wind resources, compared to Wyoming's and New Mexico's, may not offer enough of an advantage when focused on capacity factors for these three areas versus the incremental costs of building transmission for export capabilities from Colorado. Colorado has marginally better wind than New Mexico; however, New Mexico's wind resources are located closer to the Southwest load centers. Wyoming has more Class 5 wind than Colorado, and, with the potential development of the Gateway West[208] and TransWest Express[209] proposals, Wyoming may have access to more markets. However, the Wyoming projects face greater complications relative to development because they pass through many federal lands, triggering uncertainties and delays associated with the NEPA process. Competing with wind in Wyoming—and with a line similar to Gateway West that is being developed by a large western utility with retail markets in numerous western states—will be a challenge for Colorado transmission and renewable developers.
- Solar in Colorado may be at a competitive disadvantage because Arizona, California, and Nevada have higher DNI factors and do not require long lines to reach population centers. Arizona is within or close to the Southwest loads and has an easier potential to expand its interconnection with California and Nevada. Major transmission investments would be required to deliver Colorado solar resources to these Southwest markets.[210] The New Mexico Renewable Energy Transmission Authority commissioned a study by the Los Alamos National Laboratory, including the prospects for exporting renewable energy from the state.
- Investments in transmission built in Colorado for export may be contentious from a cost recovery standpoint unless a clear and quantifiable benefit for Colorado customers can be demonstrated. This is challenging because long distance lines must, by definition, be at high voltages to avoid high line losses. As the voltages increase, however, so do the costs.
- Colorado is akin to an electric system island located on the eastern end of the Western Interconnection. Without an RTO, generators lack access to a liquid electric market. This structural reality may signal a market for developers to build in Colorado first and foremost to meet Colorado's RES that is the highest in the interior western United States. Renewable energy developers continue to view Colorado as a strong market. However, they may be cautious about pursuing a business plan predicated largely on serving an export market until such time that a clear regulatory pathway for expansion of high-voltage transmission for an export market is in place.

- Although it is a long distance from Wyoming to the Southwest, two major transmission projects are envisioned to deliver renewable resources. It remains to be seen whether they will be built.

Based on the discussion items presented, long-term transmission built for export of Colorado's renewable energy should not be viewed as an absolutely necessary part of Colorado's long-term conceptual transmission plan's vision. The recovery of costs under the current methodologies available in today's statutory regulatory environment and the lack of a substantial advantage for Colorado's wind and solar resources compared to nearby states that are closer to load centers represent potential barriers to transmission designed for export in Colorado.

CCPG's Export Scenario Development

CCPG's Conceptual Planning Work Group is developing three scenarios to prepare a 20-year conceptual transmission plan. One scenario is investigating a high-transfer case for import and export of 1,000 MW in and out of Colorado via the following paths:

- Colorado to Wyoming
- Colorado to New Mexico
- Colorado to the Western Slope (Four Corners)
- Colorado to the Western Slope (Four Corners and Bonanza)

The study includes a "tabletop exercise" on large import and export to and from Colorado. If the 1,000 MW are in excess of Colorado's requirements, with large amounts of wind generation, additional concerns regarding area control generation will need to be reviewed.

Conclusion

Colorado's abundant renewable resources are clearly quite capable of meeting the needs of the state's RPS requirements and then some. The Southwest and Southern California also have rich renewable resources and RES policies are in lace in those states. Once it is clearly determined how their RES policies will be implemented, the results may encourage imports if an export scenario proves to be cost effective. On the other hand, the states' policies may effectively restrict imports because they do not aid their state's economic development objectives.

A clear consensus does not exist on whether developing transmission for the primary purpose of exporting Colorado's renewable energy represents a direction that should be taken. Increased interconnection with other states provides benefits by gaining access to more reliable and liquid energy markets, which may favor the suggestion to export Colorado's renewables. A variety of entities, including renewable energy developers, transmission expansion planning activities at the Western Governors' Association, NREL, HPX, and the WECC, will continue to closely monitor RPS and other electricity sector policies in the West to estimate and forecast opportunities for renewable energy in the West, including long-distance interstate power delivery.

Colorado needs to maintain and strengthen its relationships with the High Plains Express, the Colorado Coordinated Planning Group's Conceptual Planning Work Group, and other entities that are continually analyzing the opportunities for exporting Colorado's renewable energy.

12. Promising Transmission and Grid Technologies

Overview

Contemporary observers of the electric power system may point out that Thomas Edison would recognize many technologies used for long-distance power transmission today. Standard electric transmission technologies have proven their worth over time, and thousands of incremental improvements to transmission technology have contributed to electric power– what the National Academy of Engineering has called "the greatest engineering achievement of the 20th century."

Advanced technologies are steadily emerging that are designed to meet new demands on the electric system in the digital age. These new demands include integration of increasing amounts of variable renewable generation, evolution of wholesale trading in some markets, and increased responsibility to ensure security and reliability. An important potential exists for new transmission technologies to substantially increase the throughput of electricity compared to past practices. Yet, it is understood that utilities and regulators operate in an investment and statutory environment where risk-taking must be balanced with the need to ensure system reliability. The challenge is how to ensure timely deployment of new transmission technologies in this risk-averse environment. Although the rate of change is often frustrating and slow, new technologies are increasingly being deployed that offer improvements to the electric power system.

The American Physical Society released a November 2010 report, *Integrating Renewable Electricity on the Grid*,[211] regarding renewable energy and the electricity grid. The society called on U.S. policymakers to "focus more closely on developing new energy storage technologies as they consider a national renewable electricity standard." One principal recommendation in the report, by the Society's Public Affairs Office, regards energy storage. The study states the DOE should: develop an overall strategy for energy storage in grid-level applications that provides guidance to regulators to recognize the value that energy storage brings to both transmission and generation services on the grid; conduct a review of the technological potential for a range of battery chemistries, including those it supported during the 1980s and 1990s, with a view toward possible applications to grid energy and storage; and increase its research and development in basic electrochemistry to identify materials and electrochemical mechanisms that have the highest potential use in grid-level energy storage devices.

New Transmission Hardware Technologies

Superconducting Direct-Current Cable

Superconducting direct-current cables are flexible, single-crystal, high-temperature cables that enable high-performance advantages for electric power grid applications. Because these cables are round, rather than flat like conventional wires, they lose less heat and energy, making them more cost-effective (Figure 97). Bundled into larger-dimension wire of any shape, superconducting wires can carry five times more power than copper cables. They also are capable of long-distance power transmission although, to date, they have been used only for shorter distances of a few hundred meters at most.

Figure 97: The few ultrathin high-temperature superconducting wires on the right carry as much power as all the copper shown on the left. *Source: AMSC* [212]

The Electric Power Research Institute (EPRI) recently published a report that concludes that, "direct current superconductor cable is feasible for development using today's technology," and describes "the design of a superconducting direct current (DC) cable system capable of moving thousands of megawatts of electricity between regions, and that is practical and ready for commercial development, using today's technology."[213]

American Superconductor's Superconductor Electricity Pipelines combine conventional underground pipeline construction techniques with revolutionary, high-capacity superconductor cables and multiterminal DC/AC power electronic converters (Figure 98). The underground construction technique enhances aesthetics and increases security against natural or man-made threats.[214]

Southwire Company's aluminum-conductor, steel-supported (ACSS) transmission conductors address the need for higher capacity through existing rights-of-way and reconductoring projects. The advantages of Southwire's ACSS conductors include their steel core (no composites) and a lower price point than some competing advanced transmission technologies. According to Southwire, the core enables it to perform on par with more exotic high-temperature, low-sag conductors. It adds more strength without adding weight, which allows the high-strength cable to be pulled tighter.[215]

3M's Aluminum Conductor Composite Reinforced (ACCR), for which Southwire is the contract manufacturing partner, offers two to three times the capacity of an existing line without the risks and delays of major construction projects and without exceeding the mechanical or clearance limits of existing towers. Where new lines are necessary to bring renewable energy from remote areas to load centers, 3M ACCR can be installed on sections where permitting, environmental impacts, or aesthetics raise issues or cause delays. In these sections, 3M ACCR can be installed using existing, fewer, or shorter structures.

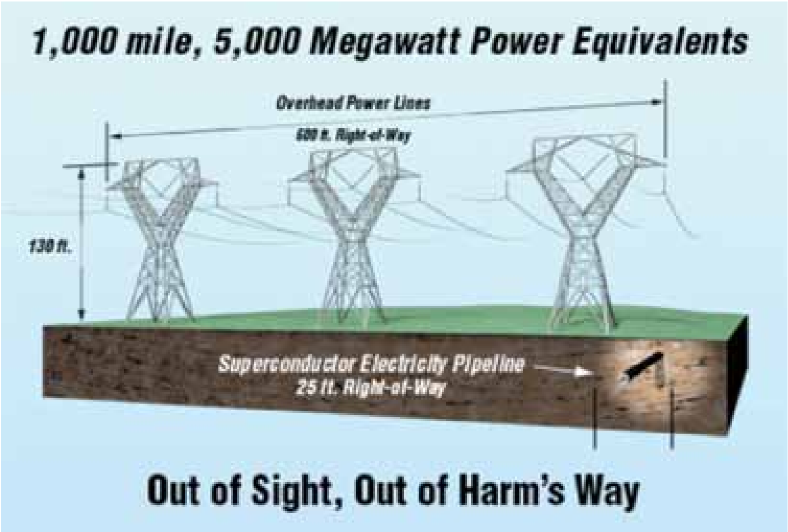


Figure 98: Superconductor Electricity Pipeline
Source: American Superconductor[216]

Construction then can continue with conventional materials.[217]

For more than 100 years, electrical power has been transmitted over heavy steel and aluminum wire. This aluminum conductor steel reinforced (ACSR) wire has been used in the vast majority (over 80 percent) of electric transmission lines. In 2004, CTC Cable Corporation introduced a new design of its proprietary annealed aluminum ACCC conductor (Figure 99). ACCC conductor offers superior performance and longevity compared to other conductor types, uses more aluminum with higher temperature capability, and now has been successfully deployed in thousands of kilometers of grid applications. The ACCC "high efficiency conductors" demonstrate less electricity line losses when compared with conventional conductors, enable power generators to reduce the amount of power they must generate, and still deliver the same power to customers. They also have demonstrated significant savings in upgrade capital costs and operating expenses when substituted in grid systems for other conductors. ACCC conductors provide a reserve electrical capacity by operating at higher temperatures without significant thermal sag of the lines.

Built on the highly evolved foundation of aerospace-proven carbon fiber hybrid composites, the ACCC conductor uses a high-strength, lightweight, and dimensionally stable, single-strand, composite core that is wrapped with trapezoidal-shaped aluminum strands. The conductor's hybrid composite core resists degradation from vibration, corrosion, ultraviolet radiation, corona, chemical, and thermal oxidation, and, most important, cyclic load fatigue. It is noteworthy that, when developers in the aerospace community were designing hybrid carbon composites, their key objective was to increase both the performance and longevity of airframes and key structural components—an objective shared by CTC Cable during

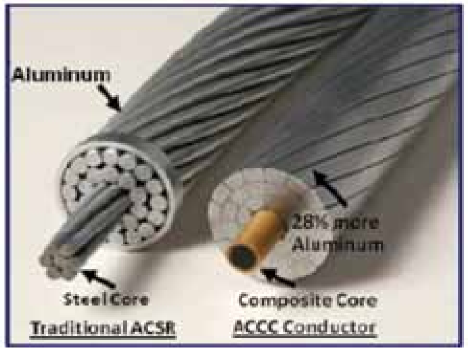


Figure 99: ACCC Conductor
Source: CTC Cable

development and deployment of the ACCC conductor. A conductor, during its anticipated service life of several decades, undergoes constant changes in temperature, tension, and wind-induced Aeolian vibration. While the ACCC conductor offers several advantages over other conductor types, its primary technical attributes are improved.

Superconducting Fault Current Limiters

Fault current limiters (FCLs) are devices that limit the prospective fault current when a fault occurs (e.g., in a power transmission network). The term generally is applied to superconducting devices, since non-superconducting devices (such as simple inductors or variable resistors) typically are termed fault current controllers. The ground fault circuit interrupter is commonly used in residential installations. Low-temperature superconductors cannot be used for commercial FCLs because the AC losses require cryogenic cooling, which makes them uneconomical. Applications for FCLs are likely to initially be developed for military applications in electric-drive ships and submarines. Many more FCLs eventually will be used to help control land-based electricity distribution and transmission systems.

Synchrophasers

Synchrophasors are precise grid measurements now available from monitors called phasor measurement units (PMUs). PMU measurements are taken at high speed (typically 30 observations per second—compared to one every 4 seconds using conventional technology). Each measurement is time-stamped according to a common time reference. Time stamping allows synchrophasors from different utilities to be time-aligned (or "synchronized") and combined to provide a precise, comprehensive view of the entire interconnection. Synchrophasors better indicate grid stress and can be used to trigger corrective actions to maintain reliability. The industry's effort to increase use of synchrophasors is centered on the North American Synchrophasor Initiative (NASPI) (Figure 100).

The PJM Interconnection and 12 member transmission owners are deploying more than 80 additional synchrophasors to optimize the transmission system and its reliability. The deployment is supported by a $14 million DOE-matching stimulus grant. The units will be installed at substations in ten states. PJM has fewer than 20 synchrophasors in operation.[219]

MISO will be the first RTO to conduct a grid-scale synchrophasor deployment; half the cost was borne by a DOE smart grid stimulus grant. More than 150 synchrophasors will be installed to more accurately measure voltage and current in MISO. These are expected to provide enhanced grid reliability and stability and possibly more transmission capacity. An initial research phase will help confirm that the project and its components are working properly and why, which will help replicate synchrophasor technology elsewhere. Although hundreds of synchrophasors are in use today, it is anticipated that thousands will be deployed as part of the transition to a smarter transmission grid.[220]

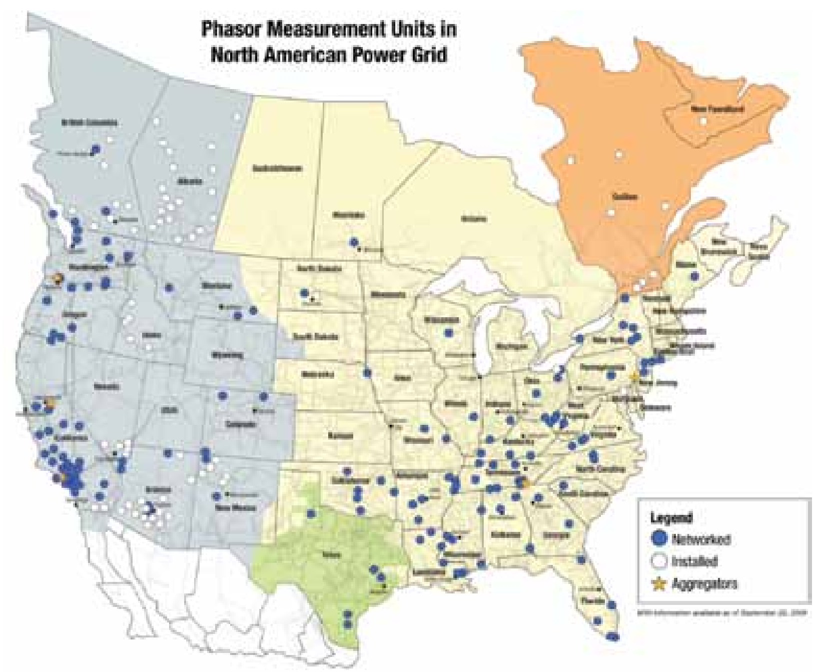


Figure 100: Existing and Planned PMUs in North America
Source: NASPI [218]

Sensor Technologies

EPRI researchers also have ongoing research and development focused on sensor technologies and the associated infrastructure needed to help utilities address an aging transmission fleet. Efforts also are being made to investigate ways to increase the capacity of existing assets and develop the next generation of equipment and technologies. EPRI has published a white paper that reviews the areas of research, from sensor applications to visualization, as described for transmission lines and substations.[221]

Carbon Nanotubes

Rice University researchers have recently developed carbon nanotubes, which are hundreds of meters long and could potentially be used as electric transmission lines. The problem today is that manufacturing such transmission lines will require huge quantities of the metallic nanotubes. The Rice project, which started in 2001, has determined that a process involving a super-acid—called chlorosulphonic acid—can be used in large-scale production of well-aligned carbon nanotubes. The high conductivity of the metallic nanotubes could offer several benefits. They conduct electricity better than copper, are lighter, and fail less frequently.

Although current manufacturing technology is not adequate to economically produce the vast quantity of nanotubes needed for transmission lines, recent research has yielded some promising results, and researchers say a breakthrough could occur in the near future. Carbon nanotubes may provide other applications, as well. MIT researchers have been working to develop supercapacitors and high-capacity batteries that incorporate the nanotubes. They also are evaluating the possibility of producing nanotubes on a much smaller scale as tiny springs that could be used for energy storage.[222]

Software Technologies

Wide-Area Monitoring Systems

The widespread implementation of PMUs[223] has led to wide-area monitoring systems (WAMS) that enable electric system operators to better understand the status of widely dispersed parts of the transmission system. PMUs transmit this system information continuously to data centers where computers record and monitor the state of the entire power system and perform actions to maximize power flow and maintain system stability.

Fault detection and proper relay functioning are among the most important tasks in transmission systems, addressing approximately 70 percent of all major disturbances and, in most cases, limiting the damage or scope of the fault. By using PMUs and updating snapshots in real time, faults can be detected quickly. By storing this data in a centralized location, relay coordination during faults can be optimized for the situation, resulting in the best fault-clearing schemes.

Analyses of recent blackouts have demonstrated that a major challenge to keeping the lights on is maintaining situational awareness (Figure 101). Moreover, grid operation occurs in a complex set of circumstances. The boundaries of areas affected by a widespread outage cover many technical control areas and administrative, state, and regulatory borders that all affect how information is processed. It is a complex task to integrate and understand the roles of human factors in information processing to ensure that operators make the best possible decisions.

Figure 101: Factors Affecting Situational Awareness

Source: National American SynchrPhasor Initiative[224]

OpenPDC

Phasor data concentrators (PDCs)—devices distributed throughout the transmission system—are designed to collect data from the many phasor measurement units. Due to the high volume of data collected, each node typically collects data from only five or six PMUs and forwards it to concentrator devices. In October 2009, the Tennessee Valley Authority (TVA) released data collection software for industry use called SuperPDC, which is responsible for aggregating measurements from multiple PDCs and archiving them for subsequent event analysis. It is now available under an open-source license under the name OpenPDC.

This software allows the TVA to collect data from its 120 online PMUs that together measure almost 2,000 parameters several times per second (Figure 102). In all, the TVA archives 150 million measurements per hour, requiring 36 GB of storage space per day.

Electric Energy Storage

Energy storage encompasses technologies that store electricity on the electric utility grid to provide power and energy where and when it is needed. Growing interest in energy storage technologies is being driven by integration of variable renewable energy sources, such as wind and solar, and the associated transmission challenges to

Figure 102: Data Collected from Online PMUs

Source: National American SynchrPhasor Initiative[225]

get the power to load centers on the grid. Energy storage technologies will play a role in transforming the electricity grid into a more reliable, secure, and efficient network capable of responding to the expected future major changes in energy demand and energy policies.

Energy storage provides many value streams above and beyond substitution of the need for peaking generation plants (peakers). By their nature, gas-fired peaker plants cannot be economically sized below generally 30 MW to 50 MW, and therefore are not easily installed in a distributed footprint. Energy storage systems do not have this limitation, which opens the potential for many technical and economic benefits available to distributed energy resources, including reduction of transmission and distribution losses. Additional benefits include electric energy time shift, voltage support, electric supply reserve capacity, transmission congestion relief, and frequency regulation. Ranges for each of these value streams have recently been quantified by Sandia National Laboratories and are presented in Figure 103.

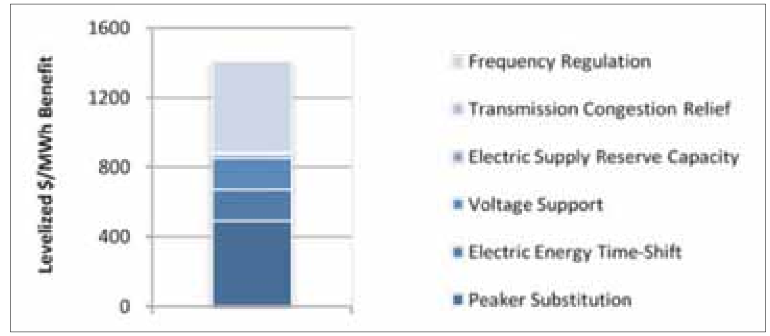


Figure 103: Additional System Benefits of Energy Storage

Source: Sandia National Laboratories[226]

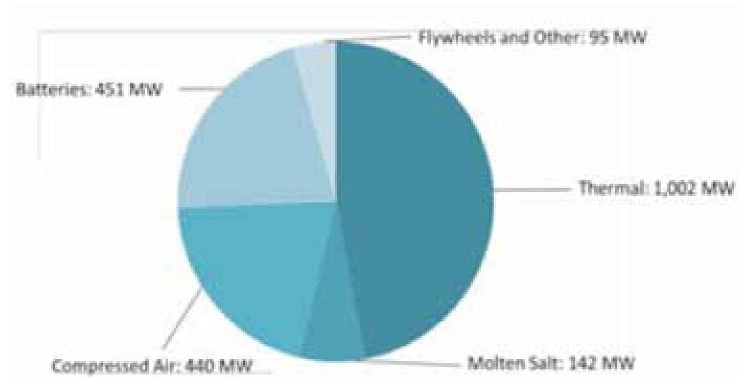


Figure 104: Estimate Installed Worldwide Capacity for Energy Storage

Source: Sandia National Laboratories[227]

Although it represents only a tiny portion of the total potential, a considerable number of installed energy storage devices exist worldwide. The current worldwide installed capacity as of 2010 is 2,128 MW. A breakdown of the particular technologies that make up this total installed base is shown in Figure 104.

According to AWEA, there may be a certain misconception that storage is critically important to wind power. The association's fact sheet, *Wind Power and Energy Storage* describes why storage is not a predicate for large scale deployment of wind.[228]

Applications for Different Energy Storage Technologies

Figure 105 provides an overview of how various energy storage technologies perform along two key dimensions: rated power and discharge time. Increased renewable energy penetration also creates the need for three broad storage applications segments, from fastest to slowest discharge time: power quality, bridging power, and energy management (the industry has made these applications more specific as well).

The figure shows the range of major storage technologies, from pumped hydro, to compressed air (CAES), to advanced batteries such as lithium ion (which have seen enormous recent global investment and buildup) and flow, as well as more power-rich technologies such as flywheels.

It is possible to evaluate the relationship between system flexibility and large-scale penetration of variable generation, both with and without energy storage or other enabling technologies. As shown in Figure 106, the degree of flexibility affects the potential curtailment of wind and solar energy when deployed without storage. These two charts superimpose


Flywheel

load data in Electric Reliability Council of Texas (ERCOT) from 2005 with a spatially diverse set of simulated wind and solar data from the same year.

The simulation places 19 GW of wind and 11 GW of solar (representing an 80 percent/20 percent mix of wind and solar based on energy) into the ERCOT system, which had a peak demand of 60.3 GW. In the left chart, it is assumed that the system will be unable to cycle below the 2005 minimum point of 21 GW, resulting in substantial variable generation curtailment. In this simulation,

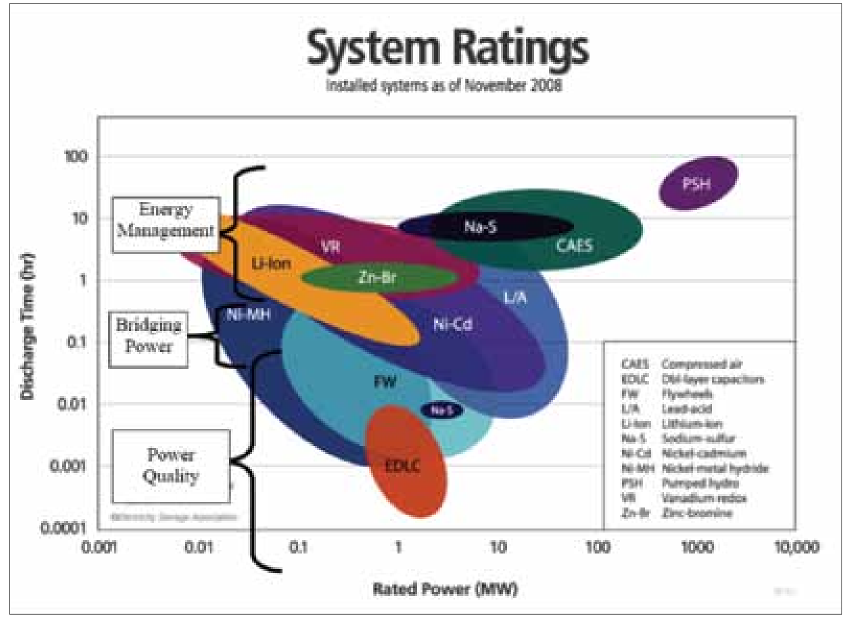


Figure 105: Energy Storage Applications and Technologies Rated Power Vs. Discharge Time

Source: NREL and Electric Storage Association [229]

wind and solar provide 20 percent of the grid's annual energy, and 21 percent of the total renewable energy production is curtailed. The chart on the right shows the result of increasing flexibility, thanks to the introduction of storage technology, which allows a minimum load point of 13 GW. Curtailment has been reduced to less than 3 percent, and the same amount of variable renewables now provides about 25 percent of the system's annual energy.

Energy storage technologies are beginning to be proven in the commercial utility market. A123 Systems, a developer and manufacturer of advanced nanophosphate lithium ion batteries and systems, recently announced an order of 44 MW of A123's Smart Grid Stabilization Systems (SGSS) for various new projects for AES Energy Storage to be completed by the end of 2011.[230] The nation's largest utility-scale battery, a 4-MW sodium-sulfur battery system, was recently energizing in Texas.

Xcel Energy has teamed up with Xtreme Power on a project involving a 1-MW

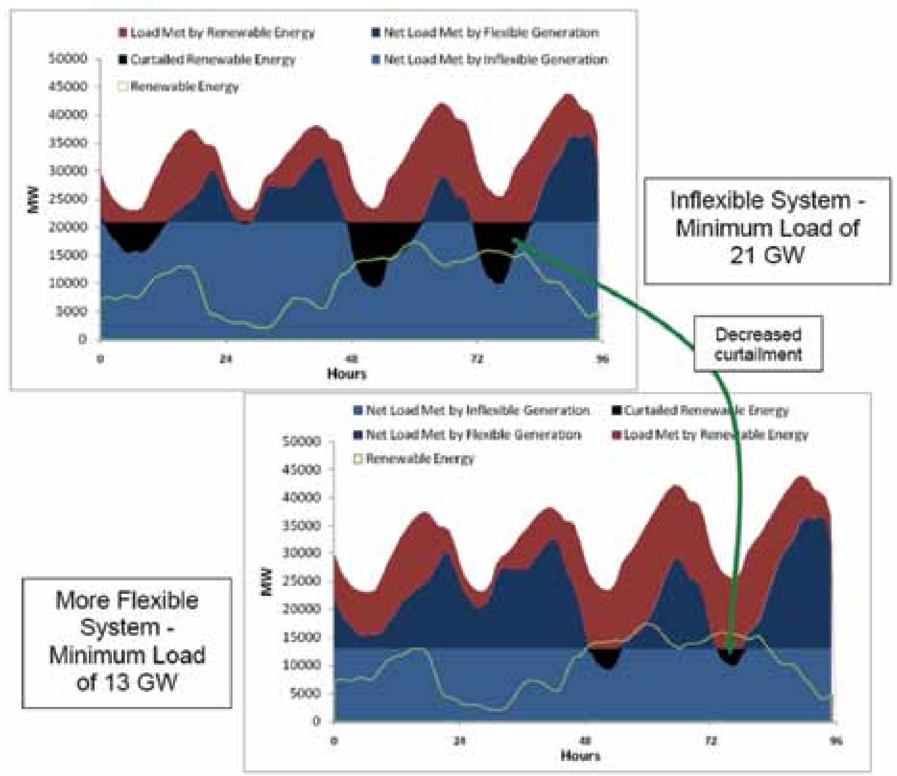


Figure 106: System Flexibility vs. Load

Source: NREL[231]

battery to store energy from solar facilities to study how to efficiently incorporate energy output from renewable sources onto the transmission grid. The research will take place at Solar Technology Acceleration Center, near Denver International Airport.

On October 7, 2010 Mexican President Calderon announced that Rubenius, a Dubai-based alternative energy and smart grid enabler, is expanding into Baja California, Mexico and San Diego, California. The company plans to install 1,000 MW of NAS energy storage batteries. The location was chosen because of its existing infrastructure and close proximity to both the Baja California power grid and the U.S. grid including the new Sunrise Power Grid expansion.

There is also momentum on the legislative front. California passed Assembly Bill 2514 in June 2010. The law requires the California Public Utilities Commission (CPUC) to establish roadmaps for major electricity providers to procure energy storage systems. Procurement targets will be established by October 2013, with the first stage to be implemented by December 2015. The law essentially requires energy storage in future build-outs of renewable energy and fossil fuel-based assets that provide ancillary services. DOE-funded energy storage demonstrations will provide data on the viability and cost-effectiveness associated with storage technologies as the CPUC establishes its 2015 and 2020 targets. A federal Storage Technology of Renewable and Green Energy Act of 2010 Act (Storage Act) has been proposed by Senator Wyden (D-OR) and others. The legislation would offer up to $1.5 billion in tax credits to storage projects.[233]

Figure 107: Ice-Ready Rooftop Units (RTUs)

Source: ICE Energy[232]

Energy Storage Opportunities in Colorado

Thermal Energy Storage

A number of Colorado companies are positioning themselves to capture opportunities in the energy storage market. In Windsor, Colorado, ICE Energy is developing distributed energy storage systems that enable how and when energy is consumed for air conditioning (Figure 107). The Ice Bear system is designed to absorb off-peak load and dispatch it on-peak, while consuming an equal or lesser amount of energy in each building, creating the industry's first effectively lossless storage solution. Using thermally efficient, off-peak power to produce and store energy for use during peak hours the following day, the Ice Bear system reduces peak energy required by conventional air conditioning systems. AC energy demand—typically

40 percent to 50 percent of a building's electricity use during peak hours—can be reduced substantially.

Pumped Hydroelectric Storage

Pumped hydroelectric storage (PHES) plants supplement transmission facilities because their primary purposes are storage, grid balancing, and ancillary service provision, not electricity generation. These plants are economical to run, due to peak/off-peak price differentials and their provision of ancillary services. Their initial capital costs are high, however, and their environmental footprint, like many other generation sources, is controversial. A 390-MW pumped hydro facility is in the planning stages, with a goal of constructing the facility at Phantom Canyon, near Florence, in the south-central part of the state.

University of Colorado researcher Jonah Levine authored a paper[234] that identified locations for PHES additions in Colorado. The targeted locations already had suitable infrastructure. U.S. Bureau of Reclamation (USBR) hydro projects in Colorado surveyed by Mr. Levine are the Colorado Big Thompson and the Frying Pan Arkansas. Favorable site characteristics of PHES include high head potential, water availability, areas conducive for fore-bay and after-bay construction or use, transmission or distribution line adjacency, utility right-of-way, renewable generation development, strong wind or solar potential, and a road. Figure 108 shows a chart prepared by Levine's research.

Conclusion

A number of promising technologies hold considerable promise for further improving the existing transmission system and positioning it to meet future operating requirements. For a complete description of storage technologies, see Electricity Storage Association.[236]

Site Name	Ownership	Capacity	Head
Mt. Elbert	USBR	200 [MW]	438 [ft]
Flat Iron Pumping Plant	USBR	8.5 [MW]	240 [ft]
Horsetooth College Lake	USBR	10 [MW]	200 [ft]
Pinewood Carter	USBR	108 [MW]	840 [ft]
Cabin Creek	Xcel Energy	324 + 35 [MW]	1,226 [ft]
Phantom Canyon	Private Developer	390 [MW]	800 [ft]
Total		1,075.5 [MW]	

Figure 108: Pumped Hydro Projects in Colorado, Installed and Proposed

Source: Pumped Hydroelectric Energy Storage and Spatial Diversity of Wind Resources as Methods of Improving, Utilization of Renewable Energy Sources, by Jonah G. Levine[235]

Many new demands are being placed on transmission that will require new, innovative technologies to be successful. The principle areas for new investment in transmission technologies focus on three areas:

1. Developing new materials or new sensors that better fulfill traditional transmission system functions or provide newer, improved capability, such as sensing.

2. Developing software or systems solutions to help manage the increased flow of information requirement more effectively and to help operators improve situational awareness of a grid that will become much more dynamic, interactive, and responsive in the future.

3. Deploying energy storage solutions more effectively to help integrate more variable renewable generation technologies. These storage solutions will likely be a combination of hard assets and new business models that enable storage to be more effectively deployed systemwide.

Colorado utilities should work with interested stakeholders and report to the legislature and the PUC with recommendations for policy and practice changes that will ensure that Colorado benefits by a more rapid introduction of new transmission and grid technologies.

The Colorado General Assembly should carefully review the policy recommendations and roadmap for Smart Grid deployment contained in the 2011 Colorado Smart Grid Task Force Report.

13. Transmission Planning in Colorado

REDI Review

The REDI report suggests that "Colorado stakeholders examine the benefits, feasibility, and possible procedures for developing a state and regional long-range transmission plan. The objectives of the plan include traditional electric reliability needs, cost stability, and incorporation of the most cost-effective options to reduce CO_2 emissions."

As the REDI report suggested, the Colorado Coordinated Planning Group (CCPG) is the most effective tool in place today to provide long-term state transmission planning, combining both jurisdictional and nonjurisdictional entities into one commission. For the CCPG to effectively meet its pivotally important role, however, internal reforms are required. Should the reforms not be voluntarily initiated, external requirements stemming from PUC transmission planning rules may be necessary to achieve the goal of comprehensive transmission planning.

Background of Transmission Planning in Colorado and the West

Recap of Colorado Utilities and Transmission Ownership

Colorado has 57 electric utilities, but only a few own and operate high-voltage transmission. The two IOUs—PSCo and Black Hills Energy own transmission assets; PSCo owns the largest transmission infrastructure network in Colorado. As mentioned earlier, both PSCo and BHE operate under PUC rate jurisdiction. Tri-State is the second largest transmission provider in Colorado. The association provides wholesale power to 18 Colorado rural electric associations. Tri-State is PUC-jurisdictional, but that jurisdiction is limited to granting CPCNs for transmission at 230 kV and above and for power plants with capacity greater than 200 MW. Fifty-four Colorado utilities are either rural electric associations or municipal utilities. Colorado Springs Utilities and Platte River Power Authority have relatively few miles of high-voltage transmission to meet their needs. Western is a federal agency with major transmission presence in Colorado and other western states.

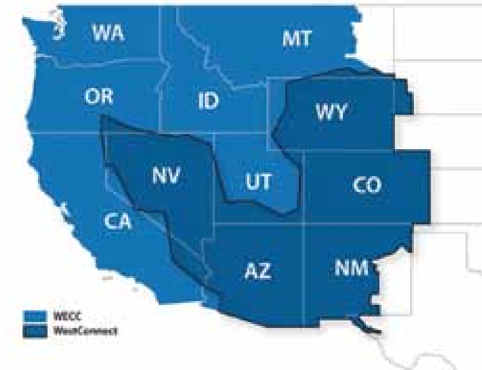


Figure 109: WestConnect Footprint
Source: National Renewable Energy Laboratory's WWSIS report[237]

WestConnect

WestConnect is composed of utility companies that provide electricity transmission in the southwest and central Rocky Mountain areas. The WestConnect footprint includes Colorado (Figure 109). Members work collaboratively to assess stakeholder and market needs and to develop cost-effective enhancements to the western wholesale electricity market. WestConnect is committed to coordinating its work with other regional industry efforts to achieve as much consistency as possible in the Western Interconnection.[238]

Colorado Coordinated Planning Group

The Colorado Coordinated Planning Group (CCPG) is a joint, high-voltage transmission system planning forum operating within the WestConnect footprint (Figure 110). CCPG's purpose is to ensure a high degree of reliability in planning, development, and operation of the high-voltage transmission system in the Rocky Mountain region. This is in accordance with the Joint Transmission Access Principles and the Electric Transmission Service Policy

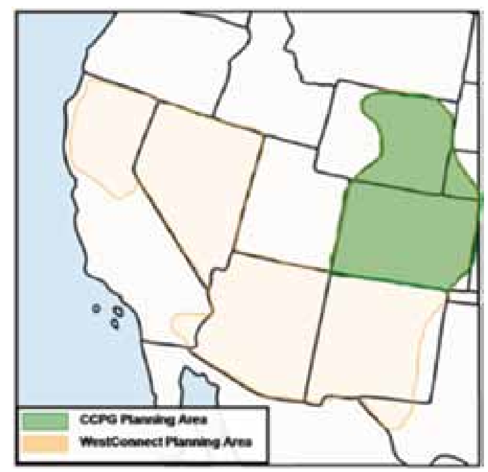
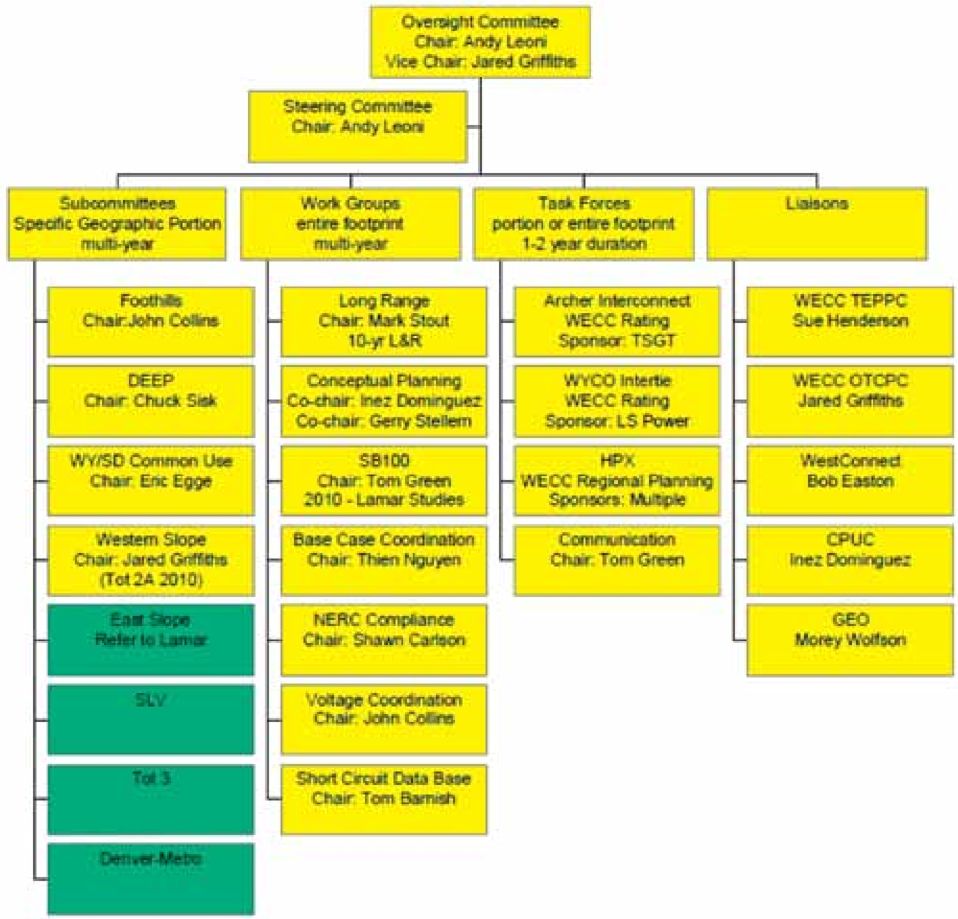


Figure 110: CCPG and Westconnect Planning Areas[239]

Statement, dated Dec. 16, 1991. The CCPG provides the technical forum required to complete reliability assessments, develop joint business opportunities, and accomplish coordinated planning under the single-system planning concept in the Rocky Mountain region of the WECC.[240] Single-system planning is defined as the planning necessary to most efficiently use the existing transmission system and to make the appropriate additions, upgrades, and enhancements to the system on a best-cost basis as if it were owned by a single entity. The planning includes evaluation of both technical and economic factors.[241]

CCPG has several workgroups with varying degrees of influence on the long-term transmission needs of Colorado and the region.

- **Colorado Long-Range Transmission Planning Group (CLRTPG):** The CLRTPG was initiated in January 2004 as a subcommittee of the CCPG. Its purpose is to facilitate open discussion and joint planning efforts for transmission in Colorado and much of Wyoming. The CLRTPG provides a forum for electric load-serving entities in the two states to jointly explore the potential for development of a coordinated transmission network.[242]



- **SB07-100 Colorado Working Group:** The SB-100 Working Group is focused on determining the adequacy of infrastructure of electric transmission facilities to meet the requirements of SB07-100 to ensure that the state's existing and future electric power needs are met.[243]

- **Conceptual Planning Work Group (CPWG):** In May 2010, CCPG formed Group the CPWG to develop a 20-year assessment of Colorado's transmission needs, incorporating emerging policies, such as the need to address climate change and integration of ever-increasing amounts of renewable energy. With close similarities to the STAR modeling analysis, the CPWG is analyzing the implication of load growth projections supplied by generating utilities, the impact of retirement of coal-fired generating stations, renewable energy import and export capabilities, carbon policies assuming legislation similar to the Waxman-Markey bill, and the transmission impacts of Colorado's RES policies.[244]

Addressing CCPG's Effectiveness

CCPG and its subcommittees represent an effort primarily by the utilities—and, to a lesser degree, by stakeholders—to move Colorado in the direction of unified transmission planning with a goal of single-system planning. Closer coordination between Colorado's utilities and the PUC is being explored through a PUC rulemaking proceeding-aimed in part at facilitating improved long-range transmission planning and coordination according to the principle of a unified system.

In principle, CCPG's goal of joint planning should aim at providing a robust state transmission system that is capable of meeting the legislative requirements of both SB07-100 and HB10-1001 to integrate increased amounts of renewable energy. Questions on the resolve of CCPG remain, however, which in part was the impetus for the PUC's NOPR on transmission planning.

Summary of the PUC's NOPR Regarding Electric Transmission Facilities Planning

After two investigative dockets were conducted over more than a year to prepare the PUC, the commission issued a NOPR on July 29, 2010, regarding electric transmission facilities planning (Docket No. 10R-526E). The NOPR states that, "Relatively recent legislative and policy changes impacted transmission planning significantly by adding germane criteria in addition to reliability and cost into consideration when considering proposed transmission planning."[245] These legislative and policy changes include certain requirements as outlined in SB07-100 and HB10-1001 for renewable energy, distributed generation, and energy-efficient technologies and therefore require the commission to become more involved in transmission planning for Colorado. The NOPR concludes that, "Both state-wide coordinated transmission planning and a meaningful involvement in such planning by stakeholders and the Commission is essential."[246]

The PUC NOPR acknowledges that, at present, the CCPG is the only statewide transmission planning open forum available to Colorado stakeholders. The NOPR states several reasons why CCPG should be the statewide entity responsible for transmission planning, including the following.[247]

- CCPG is a formal subregional planning group under WestConnect and is therefore required to develop ten-year regional transmission plans.
- Statewide transmission planning is already occurring in Colorado with CCPG. The PUC believes that, where possible and appropriate, existing institutions and long-standing practices should be incorporated into the new transmission planning rules, to avoid duplication of work that is already being done or will be done by CCPG. CPWG, as a working group under CCPG, is looking at transmission planning beyond the traditional ten-year reliability studies as well.
- CCPG has an oversight committee, a steering committee, electrical geographic-based subcommittees, workgroups, and task forces that provide additional infrastructure for the NOPR's transmission planning functions.
- The PUC agrees with CCPG's principles of consensus building, stakeholder inclusiveness, and long-term conceptual planning, which are included in the new charter.
- Certain PUC jurisdictional transmission utilities—PSCo and BHE—are members of CCPG, as are other nonjurisdictional utilities, including Tri-State, Platte River Power Authority, Western Area Power Administration, Colorado Springs Utilities, and Basin Electric.
- The PUC finds that the proposed transmission planning rules of CCPG's mission are consistent with WECC, NERC, and FERC.

Summary of Stakeholder Responses to the NOPR

Several key stakeholders provided responses to the NOPR on Oct. 15, 2010.[248] The PUC requested written and oral comments to assist the information-gathering process and help frame the issues leading to a commission decision regarding whether to go forward with formal rulemaking. At a November 2010 workshop, stakeholders had the opportunity to supplement written comments with presentations and dialogue. Comments from key stakeholders are summarized below.

Comments of CCPG

- **Ten-Year Plan:** CCPG supports development of a ten-year transmission plan. The group already performs extensive transmission planning.
- **Project Approval (CPCNs):** The group supports streamlining project approvals, including the CPCN process. It also supports a "presumption of need" arising from commission approval of transmission plans.
- **Stakeholder Outreach:** CCPG currently supports stakeholder involvement, but does not support rules that would require CCPG to become a forum for siting issues.
- **Align Transmission and Resource Planning:** CCPG agrees that transmission and resource planning processes should be better aligned. It recommends approving jurisdictional utility transmission plans developed

through CCPG and integrating those plans directly into phase 1 of the resource planning process.

Comments of PSCo, Tri-State, and BHE (Joint Filing)

- **CCPG:** Supports existing planning requirements for utilities, and states that existing CCPG processes are adequate to ensure development of an appropriate transmission plan. Notes that CCPG is voluntary and covers both jurisdiction and nonjurisdictional statewide entities. States that CCPG is not capable of handling proposed commission transmission planning rules.
- **Transmission Plans:** Describes that the commission should rework its proposed transmission planning rules to focus on the actual plans rather than supporting work papers and underlying data. Suggests that the commission should retain a filing requirement whereby utilities submit their own, or CCPG's, plans for commission review and approval. If plans are adequate, transparent, and part of an open process, the commission would grant a presumption of need in any subsequent CPCN proceeding.
- **CPCN Process:** Supports the notion that approved projects should demonstrate a presumption of need and that the CPCN process should be streamlined.
- **Stakeholder Outreach:** States that outreach should not modify existing CCPG and utility processes.
- **Align Transmission and Resource Planning:** Supports transmission planning processes that should be conducted every four years, to correspond with the PUC's timetable for electric resource planning (ERP).
- **Commission Participation in Planning:** Supports the commission providing a framework of public policy considerations that should be modeled by utilities and CCPG.

Comments of the Colorado Independent Energy Association

- **Regional Perspective:** Recommends that the commission require consideration of a regional perspective on transmission resource planning.
- **Transmission Utility Plans:** Recommends additional requirements for inclusion in utilities' transmission facility plans when filed with the commission.
- **Independent Transmission Opportunities:** Supports inclusion of required analysis of any merchant (non-incumbent or independent transmission) options proposed during the planning cycle with the commission. This would include transmission upgrades proposed by independent power producers (IPPs).
- **Align Transmission and Resource Planning:** Recommends integrating ERP and transmission planning rules.

Comments of Interwest Energy Alliance

- **Stakeholder Outreach:** Supports inclusion of early issue identification and resolution in the planning process, before finalization of a transmission plan, which will reduce controversy and associated costs.
- **Conceptual and Transmission Plans:** Recommends that conceptual plans and transmission plans be designed to build consensus on key issues over time.
- **Twenty-Year Plans:** Recommends that 20-year conceptual plans employ scenarios based on analytics.
- **Environmental Considerations:** Recommends that environmental costs and benefits be tackled early. Recommends that regional perspectives with stakeholder input be considered.
- **Public Policies:** Recommends that, in order to reasonably foresee future public policies, they must be analyzed in scenario planning.
- **Ten-Year Plans:** Recommends that ten-year transmission plans progress toward functional SB07-100 reports, resource planning dockets, and CPCN proceedings.
- **Siting and Rights-of-Way (ROWs):** Recommends that early siting decisions and ROW acquisitions be cost-effective.
- **ROW Acquisition Plans:** Recommends that confidential ROW acquisition plans be developed and filed with the transmission plans.
- **Transmission and Resource Planning:** Supports the NOPR's recommendation that transmission plans provide important assumptions for use in resource planning and RFP documents that the commission and bidders can rely upon.

Comments of the Governor's Energy Office

- **Long-Term Planning:** GEO supports relying on the CCPG, but encourages the CCPG to reform certain operational practices. GEO supports CCPG's recently formed subgroup, the CPWG, which is focused on a 20-year planning horizon incorporating key public policy trends. GEO encourages the commission to provide guidance to the CCPG and PUC-regulated utilities to incorporate key environmental externalities into generation and transmission planning.

- **Expansion of Work:** GEO supports expansion of CCPG's work to the maximum extent within the commission's jurisdiction.

- **Biennial Filings:** GEO supports the NOPR's intent to have interaction between the biennial transmission filings, CPCN proceedings, ERP, and the SB07-100 process.

- **Stakeholder Concerns:** GEO supports better transmission planning that can successfully integrate higher levels of renewable energy resources. GEO supports early identification of stakeholder concerns, with an opportunity to resolve such concerns before utilities file their CPCN applications.

- **Outreach to Stakeholders:** GEO supports a broader outreach to stakeholders through an evolution of the CCPG organizational structure, including a budget and executive director-level leadership.

- **Other Concerns:** Additional CCPG functions contemplated by the NOPR are encountering resistance from transmission owners at the CCPG. This resistance may place the state at risk of perpetuating an undersized, insular, and inadequate transmission system that may be unable to meet Colorado's long-term needs.

Comments of Western Resource Advocates

- **Transmission Planning:** WRA supports a balanced approach to transmission planning by incorporating the public interest policy goals of increasing the use of demand-side resources, distributed generation, and renewable resources with storage, while protecting natural and cultural resources.

- **Policy Objectives:** WRA supports the policy objectives of the commission in the NOPR overview, pending some described modifications.

- **Cost Analyses and Inclusion of Environmental Considerations:** WRA recommends that the term "best-cost" be defined to include not only capital costs of a project, but also environmental costs.

- **Significance of Renewable Resources to Colorado's Future:** For the 20-year plans, WRA recommends that the commission include more aggressive standards for energy efficiency and renewable resources, in excess of the RES.

- **CCPG:** WRA supports CCPG as the primary vehicle for long-term planning and coordination in the state, although WRA offers a different opinion than CCPG with respect to what should be in ten- and 20-year transmission plans.

- **Supports Economic Planning Studies:** WRA recommends that economic planning studies be conducted through CCPG. To allow CCPG to conduct such studies (since this is currently outside the CCPG charter), WRA recommends amendments to the CCPG charter through a commission approval process.

Comments of Wyoming-Colorado Intertie LLC

- Support of the Proposed Rules: WCI favors establishing a process that takes into account the needs of all stakeholders for a best-coordinated long-term solution.

- Regional Transmission Planning Focus: WCI recommends that the rules take into account regional transmission projects in order to provide additional benefits to Colorado through increased options for renewable resources, reliability, etc.

- Prioritization of Projects: WCI recommends that the rules identify how transmission projects are prioritized.

- Independent Transmission Operators: WCI supports opportunities for independent transmission operators by modifying the ten-year transmission plan to provide opportunities for these entities to sponsor transmission projects.

Just prior to the publication of this report, the PUC received comments from the parties in order to help determine how the Commission should craft the rules. The parties provided responses to the following questions posed by the PUC:

- Provide a definition of "economic study" for purposes of the proposed transmission planning rules, and whether this or a similar definition in the rules would address the definitional concerns expressed at the hearing and in the comments.
- If the commission were to grant a rebuttable presumption of need for an individual project, what information would be required to establish need and to demonstrate that the best alternative was selected?
- Provide comment on the option to have transmission plans filed only on an informational basis. Please describe what data should accompany transmission plans in this situation.
- In the context of transmission planning (before corridors are identified but the end points of transmission lines are selected) what level of outreach for stakeholder input is appropriate to county, municipal, and other regulatory agencies? Should outreach be conducted in a different manner depending on whether the transmission planning docket will be an informational docket or an adjudicatory docket?
- Senate Bill 07-100 reports are due on October 31 of odd-numbered years and the plans referenced in the draft NOPR are due on February 1 of even-numbered years. Comment on whether the two documents should be filed simultaneously and the reasons why they should (or should not) be filed simultaneously.
- Discuss the coordination of the transmission planning docket and the electric resource plans (ERPs) filed on October 31, every four years (2011 is the next required filing).

Conclusion

The PUC has indicated through its proposed rulemaking that transmission planning in Colorado needs to be more comprehensive, with a longer time horizon, increased coordination with generation planning, and greater stakeholder involvement. The PUC has held a series of workshops and has received written comments on draft rules to help the commission determine whether to initiate a formal rulemaking proceeding in 2011 to accomplish these goals.

Colorado will benefit if clarifying transmission rules are promulgated, as this will result in closer cooperation between utilities and stakeholders, featuring more diverse involvement in the planning process. It may be a challenge for utilities and policy decision makers to further professionalize the CCPG's subregional transmission planning processes in Colorado. However, the investment in this endeavor will increase the likelihood that Colorado will achieve the needed vision for strategic future priorities, such as minimizing environmental impacts, minimizing water consumption, adopting new technologies and practices in the electricity sector.

14. Integrating Renewable Energy into the Grid

REDI Review

As summarized in the REDI report, "Integrating higher penetrations of wind and solar resources into the system is another fundamental operational challenge, even after the basic challenge of transmission availability is addressed. As with transmission planning, the challenge of wind integration is somewhat less daunting when it can be addressed over a large, diverse geographic area. A 119-page wind integration report produced for PSCo in 2006, in response to a PUC requirement, provides detailed estimates of the additional ancillary costs to integrate wind at 10 percent, 15 percent, and 20 percent penetrations. NREL is at the forefront of efforts with industry partners to address the wind integration challenge."

Overview

As wind and solar are on a steady path of expanding their position in utilities' generation portfolios, utilities continue to look for new ways to efficiently and cost-effectively integrate these renewable resources into their systems. According to AWEA: "Utilities can typically add wind power to their portfolios without major adjustments in the planning, operations, or reliability of their systems, according to studies looking at experience or modeling wind integration scenarios, as well as experience in Europe where wind energy development is much more widespread. Integration adjustments are lowest when new wind power is being integrated into a broad region with modern, properly-crafted tariffs and a diverse mix of power sources, such as natural gas and hydropower."[249]

As renewable penetrations increase in the generation portfolio, operators continue to meet mandatory reliability criteria. These criteria are based on grid frequencies and require operators to maintain frequencies within certain levels across different time frames. As policymakers in legislatures, voters through initiatives, and regulators move to raise renewable energy standards, operators, who must maintain mandatory reliability standards, are challenged by increased renewable energy penetration. It is essential that changes are made to allow both reliability to be maintained and wind and solar to be added to generation portfolios to the maximum extent possible.

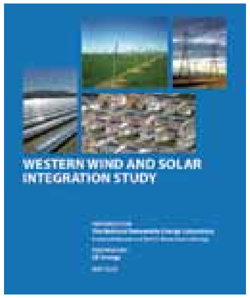
Nationally and internationally, power system engineers (with help from various research institutions, consultants, and stakeholders) have conducted studies that consider numerous solutions focused on successful integration of variable resources. From consolidating balancing authorities, faster scheduling, and adding more flexible thermal generation, to better forecasting, broader access to regulation markets, and new modeling and grid control techniques, a menu of "least cost" integration solutions are emerging across the United States, with successful results that provide opportunities for increasing renewable resources in the coming years.

Internationally, countries such as Denmark, Germany, Ireland, and Spain, all with high levels of renewable penetrations, have successfully changed their operations, regulations, and market structures to improve integration of their wind generators. Spain's wind penetration levels were nearing 10 percent as of 2007. The country has experienced relatively rapid capacity drops of up to 1,000 MW, since wind over speed conditions can cause wind turbines to shut down to protect themselves from conditions beyond their engineering tolerances. Renewable energy now contributes over 27 percent of Scotland's electricity consumption. Scotland recently raised its renewable energy target from 50 per cent to 80 per cent by 2020. A consortium of academic and industry representatives convened to establish regulations for wind generators, causing incidents (limited to those events in excess of 100 MW) to drop significantly in 2009 from the high levels seen in 2007. The Spanish experience with new approaches shows that cost-effective solutions can be found to the problems posed by high levels of renewable energy generation.[250]

On Dec. 15, 2010, the New England Independent System Operator said that wind could cover 24% of New England's power needs by 2020. However, integration of that magnitude would require major transmission upgrades, as well as increased operating reserves and regulation services. That level of wind would also require accurate intra-day and day-ahead wind power forecasts to ensure efficient unit commitment and market operation. Collectively the six states in the ISO-NE footprint have a goal of meeting 30% of New England's projected total electric energy demand through renewables and energy efficiency measures by 2020.

In the western United States, wind and solar integration is becoming increasingly important as renewable resources become a greater share of utilities' generation portfolios. Renewable Portfolio Standards in four of the five states in WestConnect require that 15 percent to30 percent of annual electricity sales be derived from renewable resources by between 2020 and 2025. Most of the states in the WECC have RPS requirements, and renewable energy growth in the western region has been significant.[251]

Western Wind and Solar Integration Study



One of the most in-depth studies concerning the operational impacts of integrating wind and solar into the Western region is the 536-page *Western Wind and Solar Integration Study (WWSIS)* [252], produced by NREL and GE Energy. The study examines grid operations for the year 2017 and the operational impact of up to 35 percent energy penetration of wind, PV, and CSP on the WestConnect system, which includes utilities in Arizona, Colorado, Nevada, New Mexico, and Wyoming. WestConnect also includes utilities in California, but this area was not included in the study because the state had already completed a renewable integration study. This area, as defined in the study, is referred to as "in footprint" or "footprint."

The *WWSIS* report was designed to answer the questions that utilities, PUCs, developers, and regional planning organizations have regarding operational impacts of renewable energy integration in the West. These questions are analyzed in the report and summarized in the section entitled "Key Changes," which follows. The study analyzed operating impacts of varying levels of integration of renewables ranging from 11 percent to 35 percent. For purposes of the NREL report, the 30 percent case (defined as 30 percent wind and 5 percent solar) were the only energy penetrations discussed. The following information is extracted from the *WWSIS* study.

Operations with 35 Percent Renewables—30 Percent Case

Power systems are designed with flexibility to respond to unexpected outages of equipment and the ever-changing systems condition, including changes in load, demand, and generation output. To manage the variability of power systems with wind and solar, the network power system must be able to handle variation in net load (load minus wind and solar), and this can be considerable during certain times of the year. Figure 111 shows the load, wind, solar, and net load (blue line) profiles for the 30 percent case during two selected weeks in July and April. Depending upon the month, the variations from wind and solar can be relatively easy to manage (July chart) or more difficult (April chart), even causing a few hours of negative net load during the week as wind dominates the net load during those hours.

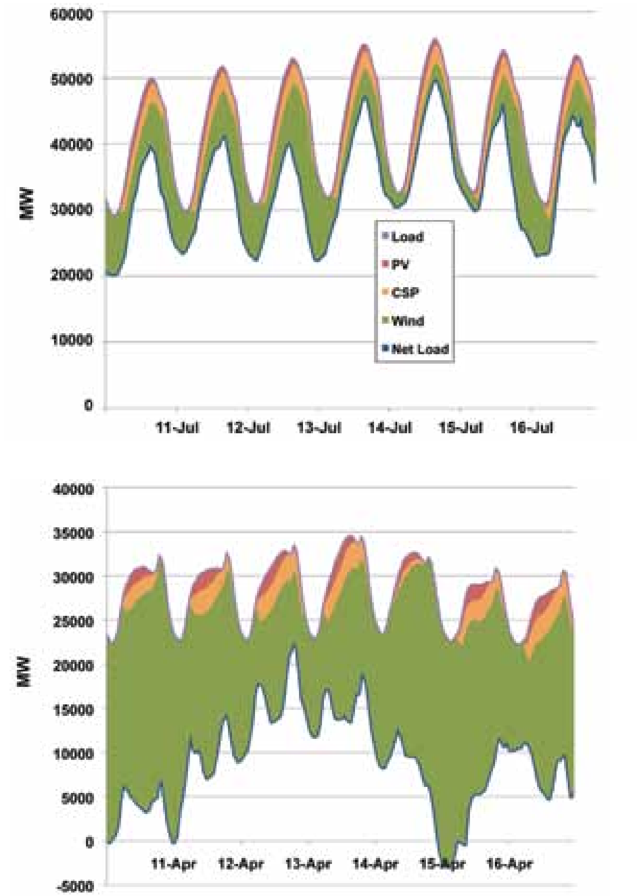


Figure 111: Balance of Generation Against Net Load

Source: NREL 2010, WWSIS[253]

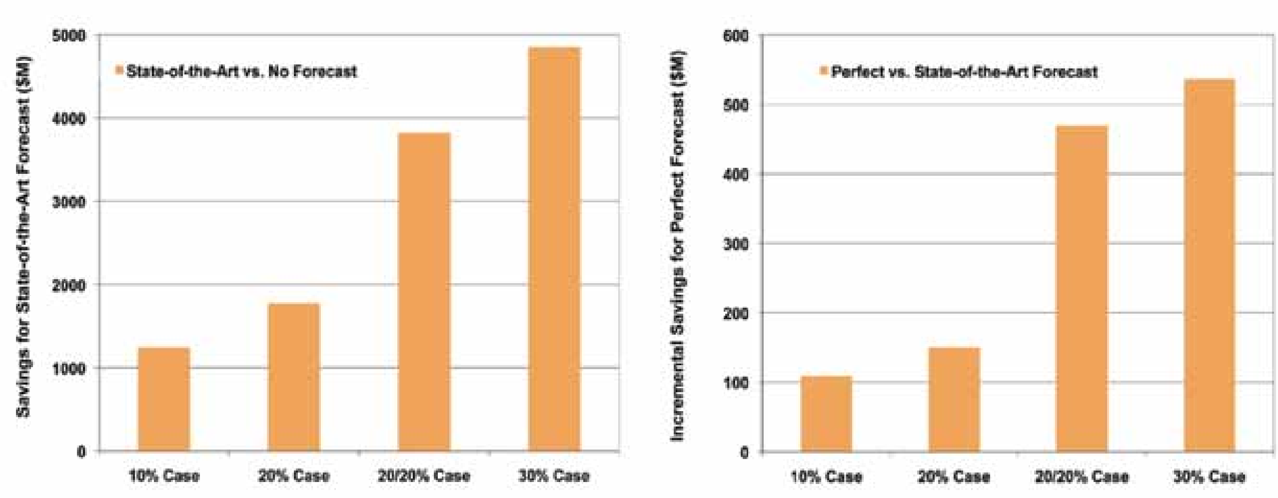


Figure 112: WECC Savings in Operating Costs for Forecasts

Source: NREL's WWSIS[254]

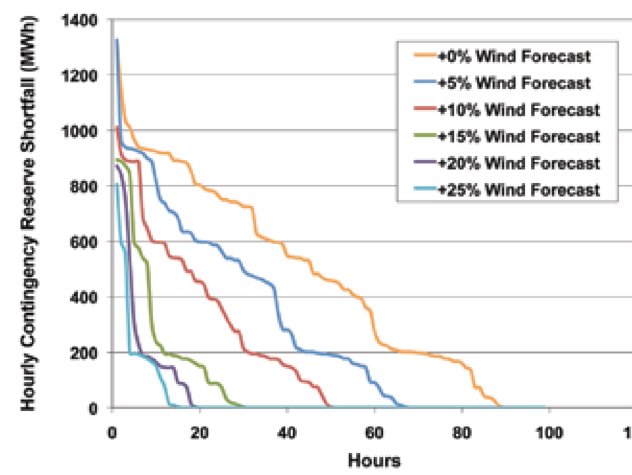


Figure 113: Hourly Contingency Reserve-Shortfall Duration Curves for In-Area 30 Percent Case

Source: NREL's WWSIS[255]

Key Changes Are Necessary to Achieve the 30 Percent Case

As shown in Figure 111, both variability and uncertainty of wind and solar generation affect grid operations. The technical analysis conducted in the *WWSIS* report demonstrates that it is operationally feasible to achieve the 30 percent case, provided significant changes are made to current operating practices. Key items of consideration, as described in the report, include the following.

- **Subhourly Scheduling:** In the *WWSIS* report, subhourly scheduling will be required to successfully operate the system at high penetration levels without significantly increased regulating reserves. The current practice of scheduling once each hour significantly affects the regulation duty. In the report, subhourly scheduling in the 30 percent case, for the footprint, was roughly equivalent to integrating 23 percent wind/solar (20 percent wind and 3 percent solar for the footprint) with hourly scheduling. This could improve plant efficiencies and reduce operation and maintenance costs, facilitating smoother system operation.

- **Forecasting—Uncertainty (Forecast Error):** The report states that, "Integrating state-of-the-art (SOA) wind and solar forecasts into the unit commitment process is essential to help mitigate the uncertainty of wind and solar generation." Such SOA forecasts for wind and solar may be imperfect, but incorporating day-ahead unit commitments is essential and would reduce annual WECC operating costs by up to 14 percent or $5 billion per year, a reduction of $12 MWh to $20/MWh of wind and solar generation. The left side of Figure 112 shows the WECC-wide operating cost savings for using SOA forecasts compared to ignoring wind in the day-ahead unit commitment. The right side shows the incremental cost savings for perfect wind and solar day-ahead forecasts, which would reduce WECC operating costs by another $500 million per year in the 30 percent case of wind and solar generation.

- **Contingency Reserve Shortfalls (Extreme Forecast Errors):** The report also states that, "On average, wind forecast error is not very large (8 percent mean absolute error across WestConnect), although there are hours when wind forecast errors can be extreme." Operating rules dictate that 3 percent of contingency reserves must be spinning reserves and, therefore, imperfect or overscheduled energy forecasts for wind and solar could lead to an under-commitment of resources, especially in the 30 percent case. The report describes how contingency reserves resulting from inaccurate forecasts come at a cost. As an alternative, the *WWSIS* report suggests using a load participation program or demand response program for the 89 hours of contingency reserve shortfalls rather than increasing spinning reserves for 8,760 hours of the year. This could result in savings of up to $600 million per year in operating costs versus committing additional spinning reserves (Figure 113).

- **Wind Curtailment and Forecasting:** In the 30 percent case, wind curtailment is estimated to be 1 percent or less of the total wind energy.
- **Variable or Load-Following Reserves:** In addition to contingency reserves, utilities are required to hold variability or load-following reserves to cover ten-minute load variability 95 percent of the time. While the need for variability reserves doubles in the 30 percent wind case, the study showed that backing down conventional generating units result in more available up-reserves (Figure 114). Therefore, commitment of additional reserves is not needed to cover the increased variability.
- **Additional Long-Distance Transmission:** In the report, up to 20 percent renewable penetration could be achieved with little or no new long-distance, interstate transmission additions, assuming full use of existing transmission capacity. Additional costs for 30 percent integration were increased, depending upon the particular transmission investments.
- **Additional Storage:** The report examined the benefits of storage, including price arbitrage (charging when spot prices are low and discharging when prices are high), reliability, and ancillary services. In particular, the report considered pumped storage hydro (PSH), solar thermal storage, and PHEVs, but focused on PSH. The report evaluated only price arbitrage for PSH and found it less than sufficient to economically justify additional storage facilities.
- **System Flexibility**: The report states that, "System flexibility is the key to accommodating increased renewable generation." *WWSIS* finds that, at higher (30 percent case) penetration levels, decreased flexibility of either the coal or hydro facilities made operation of those facilities more difficult and increased the costs of integrating renewable generation.
- **Hydro Generation:** Capable of quick start-and-stop cycling, hydro generation is a good partner for renewable energy. The report conducted sensitivity analyses to examine the effect of hydro constraints on operating costs (Figure 115).

Therefore, at higher penetrations of wind and solar, hydro generation (if normally committed and dispatched to serve daily peak net-load periods, and respecting

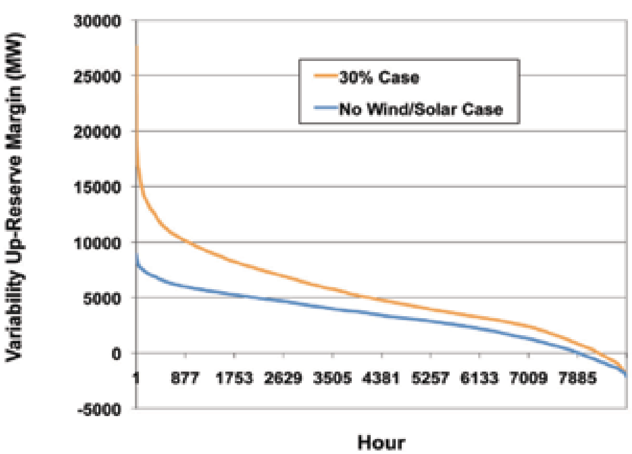


Figure 114: Variability Up-reserve Margin

Source: NREL's WWSIS[256]

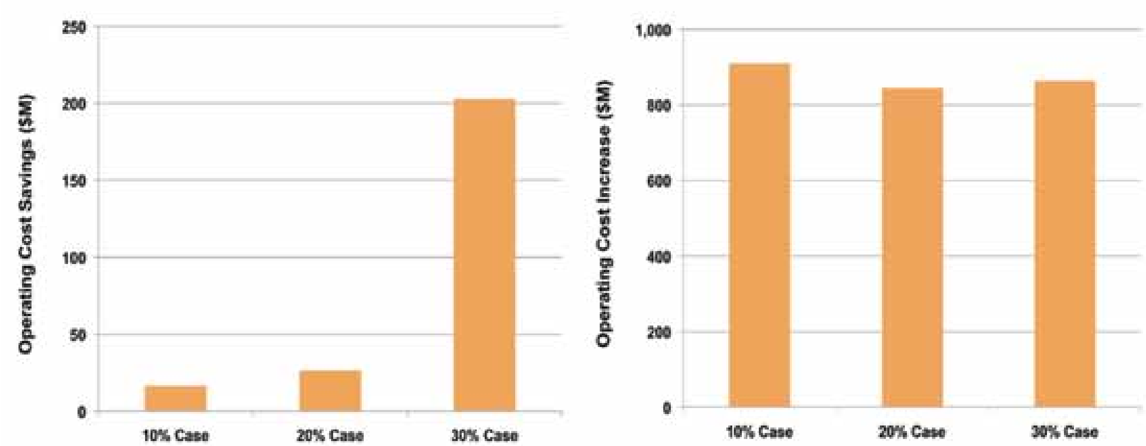


Figure 115: Hydro Output and Potential Cost Savings

Source: NREL's WWSIS[257]

the minimum operating points of the units) can reduce WECC operating costs by up to $200 million per year in the 30 percent case. This increases the value of wind and solar energy by about $1/MWh. If hydro operation is constrained, then WECC operating costs could increase by up to $1 billion per year in the 30 percent case.

- **Constraints on Coal Plants:** The WWSIS report states, "Coal plants were assumed to be able to operate down to minimum generation levels of 40% of nameplate capacity. WWSIS finds that higher minimum generation levels resulted in increased operating costs."

- **Renewables as Capacity Resources:** In the study, wind was found to have capacity values of 10 percent to 15 percent; PV was 25 percent to 30 percent; and CSP with six hours of thermal energy storage was 90 percent to 95 percent (Figure 116).

Summary of Other Recent Studies Evaluating Wind and Solar Integration Issues

Several other studies have either recently been conducted or are in process regarding integrating wind and solar, or either, into a utility's control or other study area's system.

NREL Reports

The DOE's 2008 *20% Wind Energy by 2030* report states: "Until recently, concerns had been prevalent in the electric utility sector about the difficulty and cost of dealing with the variability and uncertainty of energy production from wind plants and other weather-driven renewable technologies. But utility engineers in some parts of the United States now have extensive experience with wind plant impacts, and their analyses of these impacts have helped to reduce these concerns. Wind's variability is being accommodated, and given optimistic assumptions, studies suggest the cost impact could be as little as the current level—10% or less of the value of the wind energy generated."

The Transmission and Grid Integration Group at NREL released the following reports on the topic of renewable energy integration.

- *Market Characteristics for Efficient Integration of Variable Generation in the Western Interconnection, August 2010*[258] Authors: Michael Milligan and Brendan Kirby

Report summary: According to NREL, "WECC convened the Variable Generation Subcommittee (VGS) in 2009. The VGS was commissioned to address all issues related to the predicted increasing penetration of variable generation on reliability, both in the operating and planning time frames. The VGS was split into four Work Groups: Operations, Planning, Markets, and Technology. The Markets Workgroup was tasked with developing a white paper to address the role of electricity markets to help manage variable generation (VG). As part of the white paper effort, prior NREL work was used to provide evidence of how markets help with reliable power system operation, both with and without VG. This report, adapted from prior reports and research by the authors and others, was used in the development of the VGS Market White Paper, still in draft form at the time of this writing."

TABLE 4 – CAPACITY VALUES FOR 2004-2006.

CASE	WIND ONLY	PV ONLY	CSP ONLY	WIND+PV+CSP
10%	13.5%	35.0%	94.5%	18.2%
20%	12.8%	29.3%	94.8%	19.7%
30%	12.3%	27.7%	95.3%	19.8%

Figure 116: Capacity Values

Source: NREL's WWSIS[259]

"One primary conclusion from this survey of studies from different parts of the country is that this study lays to rest one of the major concerns often expressed about wind power: that a wind plant would need to be backed up with an equal amount of dispatchable generation."

- *Utilizing Load Response for Wind and Solar Integration and Power System Reliability, July 2010*[260]
  Authors: Michael Milligan and Brendan Kirby

Report summary: According to NREL, "Demand response is a proven set of technologies that have been used by utilities to improve reliability for decades. Improvements in communications and controls now make it practical to obtain regulation and contingency reserves as well as peak reduction from responsive loads. Real-time price response is also technically feasible, though regulatory barriers exist. FERC has assessed the current state of demand response in the United States and concluded that significantly greater capability exists. Increasing the pool of responsive resources is beneficial for wind and solar since they add variability and uncertainty to the power system at the same time that they displace generation that itself can provide response. Both voluntary price response and command and control are useful. Variable generation up-ramps are typically not a reliability concern since wind or solar can be spilled. Up-ramps are an economic concern that load response can help with. Down-ramps can be a reliability concern and are certainly an economic concern. Here too, load response can help. Wind and solar ramps are slower than conventional contingencies. Responding to large ramps will require price responsive load and may require a new reserve that is similar to supplemental operating reserve. Renewable generation advocates should work to remove barriers to demand response."

- *Advancing Wind Integration Study Methodologies: Implications of Higher Levels of Wind, July 2010*[261]
  Authors: Michael Milligan, Erik Ela, Debra Lew, Dave Corbus, and Yih-huei Wan

Report summary: According to NREL, "Wind integration studies are now routinely undertaken by utilities and system operators to investigate the operational impacts of the variability and uncertainty of wind power on the grid. There are widely adopted techniques and assumptions that are used to model system operation, examine impacts on the regulation, load following, and unit commitment timeframes, and quantify costs. As wind penetration levels increase, some of the assumptions and methodologies are no longer valid and new methodologies have been devised. Based on involvement in conducting studies, reviewing studies, and/or developing datasets for studies in WECC, the Eastern Interconnect, Hawaii, and other regions, the authors report on the evolution of techniques to better model high penetrations (generally, 20% or more energy penetration) of wind energy."

- *The Role of Energy Storage with Renewable Electricity Generation*[262]
  Authors: Paul Denholm, Erik Ela, Brendan Kirby, and Michael Milligan

Report summary: According the NREL Report, "NREL explores the role of energy storage in the electricity grid, focusing on the effects of large-scale deployment of variable renewable sources (primarily wind and solar energy). The paper begins by discussing the existing grid and the current role that energy storage has in meeting the constantly varying demand for electricity, as well as the need for operating reserves to achieve reliable service. The impact of variable renewables on the grid is then discussed, including how these energy sources will require a variety of enabling techniques and technologies to reach their full potential. Finally, the report evaluates the potential role of several forms of enabling technologies, including energy storage."

Utility Wind Integration Group Study

- *Wind Integration State of the Art*[263]

This publication, produced by the Utility Wind Integration Group (UWIG), was endorsed by the EEI, the American Public Power Association (APPA), and the National Rural Electric Cooperative Association (NRECA). UWIG's report is summarized as follows:

"Wind resources have impacts that can be managed through proper plant interconnection, integration, transmission planning and system and market operations. System operating cost increases arising from wind variability and uncertainty amounted to only about 10% or less of the wholesale value of the wind energy. A variety of means—such as commercially available wind forecasting—can be employed to reduce these costs. In many cases, customer payments for electricity can be decreased when wind is added to the system, because the operating-cost increases are offset by savings from displacing fossil fuel generation. One primary conclusion from this survey

> "We have added hundreds of megawatts of wind generation, and our overall emissions have declined."
> – Frank Prager, Environmental Policy Vice President, Xcel Energy

of studies from different parts of the country is that this study lays to rest one of the major concerns often expressed about wind power: that a wind plant would need to be backed up with an equal amount of dispatchable generation."

Xcel Energy and Wind Forecasting Success

Xcel Energy has partnered with the National Center for Atmospheric Research (NCAR) to use better tools for forecasting wind. NCAR feeds data from satellites, weather stations, and aircraft into supercomputers to determine when Xcel can ramp down coal-burning plants and use wind energy from various projects located in the Colorado Front Range. With better forecasting, system operators can dispatch power more accurately, creating a more efficient system and potentially reducing the need for coal and gas resources.[264]

Bentek Energy's Contention Regaring Wind and Air Pollution

Bentek Energy prepared a report in April 2010, commissioned by the Independent Petroleum Association of the Mountain States, *How Less Became More: Wind, Power and Unintended Consequences in the Colorado Energy Market*.[265] The report reviewed power plant records in Colorado and Texas and concluded that, despite huge investments, wind-generated electricity "has had minimal, if any, impact on carbon dioxide" emissions. Bentek found that, thanks to the cycling of Colorado's coal-fired plants in 2009 to integrate wind power, at least 94,000 more pounds of carbon dioxide were generated because of the repeated cycling. In Texas, Bentek estimated that the cycling of power plants due to increased use of wind energy resulted in a slight savings of carbon dioxide (about 600 tons) in 2008 and a slight increase (of about 1,000 tons) in 2009. The report says: "Wind energy promises a clean, renewable resource that uses no fossil fuel and generates zero emissions. Careful examination of the data suggests that the numbers do not add up as expected. The 'must take' provisions of Colorado's Renewable Portfolio Standard require that other sources of generation, such as coal plants, must be 'cycled' to accommodate wind power. This cycling makes coal generating units operate much less efficiently…so inefficiently, that these units produce significantly greater emissions. This study reviews the data that supports this conclusion, outlines mitigation measures which can be used to realize the full potential of wind generation, and provides recommendations for policy makers."

PSCo dismissed the IPAMS study. Frank Prager, Xcel's Environmental Policy Vice President, said: "Wind is not perfect. Wind turbines generate electricity only when wind blows," and continued to describe how utilities manage wind's variability. "Generally, we prefer to ramp gas-fired plants. If we ramp coal-fired units, the plant's efficiency may decline, causing its emission rate to increase for short periods. The Bentek study implies that small, short-term emission increases associated with ramping result in significant increases in the total emissions. This is simply wrong. Since 2007, we have added hundreds of megawatts of wind generation, and our overall emissions have declined."

AWEA's CEO Denise Bode stated that "the DOE has concluded that achieving 20 percent wind in 2030 would cut electric sector emissions by 25%. Denmark has cut their CO_2 emissions nearly in half since 1991 in large part because 20% of their electricity now comes from wind. Any claim that adding wind energy to the electricity grid would not reduce carbon dioxide emissions violates the laws of physics."

Conclusion

Studies are showing that it is feasible for wind and solar resources to be integrated at higher penetration levels with some changes to traditional practices.[266]To effectively accommodate the variability of these resources, key considerations must be addressed, including:

- Virtual or physical consolidation of balancing areas
- Subhourly scheduling
- Integration of new forecasting methods for proper reserve sharing responsibilities by utilities and control areas
- Additional long-distance transmission
- Additional storage
- System flexibility

Colorado transmission-owning utilities should expand their work with regional and national stakeholders regarding renewable energy integration, and report their findings to the legislature and the PUC.

15. Transmission Permitting Challenges

REDI Review

In the 2009 REDI report, the issue of transmission siting and permitting is raised as a substantial impediment to progress in the upcoming infrastructure build-out. For context, siting transmission lines has proven to be significantly more difficult than siting wind farms in recent history. The problem has become such a considerable consideration that it deserves to be investigated in greater depth. The REDI report recited many of the issues that require further analysis.

Overview

The intersection of renewable energy and transmission infrastructure with land-use issues deserves special attention. Planning and permitting new transmission lines is a complicated and time-consuming process. Construction of the lines moves relatively quickly, compared to the planning and permitting process. Because Colorado's transmission siting process is marked by strong local control and regulation, analysis of the county transmission permitting processes deserve attention.

After a utility files an application for a permit to build a transmission line, the utility will interact with local governments that have the discretion of proposing conditions, such as roposing conditions on portions of the line to be buried or requiring more costly routing to accommodate land-use concerns.

Because regional transmission projects often traverse several municipalities and counties, a transmission developer must follow multiple permitting processes within each jurisdiction through which the project passes. In some high-profile cases in Colorado, utilities have encountered permitting delays or denials because local governments have imposed conditions on the utility's application. Given the necessity of building out the transmission infrastructure to deliver renewable resource generation to the loads, and the need for greater reliability, concerns have been expressed about whether Colorado's relatively unique local approach to transmission siting decision making may be a serious enough impediment that it warrants reviewing the potential for reforming the process. Figure 117 illustrates some interlocking parts in Colorado's siting process.

As analyzed by WorleyParsons in the REDI report, in Colorado, utilities are required to obtain land-use permits from local governments before constructing a new transmission project. The permitting process in Colorado is often not consistent from one local jurisdiction to the next in regard to how permit applications for new transmission and generation are reviewed and processed. The requirements of different cities and counties vary. Some jurisdictions have no land-use regulations pertaining to energy facilities. Others have regulations that are ambiguous and difficult to navigate. Still others adopt regulations quickly after new facilities are proposed.

There is growing interest in considering streamlining Colorado's transmission planning and permitting processes. If carefully and effectively carried out, streamlining the approval process (what some call "one-stop permitting") may allow renewable energy and transmission development to occur in a more timely manner. Although many admit a problem exists, there is no consensus on an appropriate solution. A December 2010 joint letter from Colorado Counties, Inc. and the Colorado Municipal League to the PUC indicated an interest in increasing their participation in the transmission planning process. The letter states: "By conducting outreach and partnering with local governments earlier in the transmission planning process (either regionally or on a one-on-one basis), energy providers and utilities can hopefully facilitate more buy-in from the communities in question and improve their long-term chances of success in the eventual siting process. Many local governments invite meetings with the development community prior to the submission of a formal development application in order to informally discuss proposed development plans in the hopes that such discussions will lead to a better, more thought-out product that meets the needs of the developer and community at large. These meetings

Figure 117: Transmission Siting Process

Source: Public Service Company of Colorado[267]

PROJECT APPROVALS

JURISDICTION	PERMIT/DECISION/ACTION
Federal	
U.S. Department of Agriculture, Rural Utilities Service	NEPA: Title 7 Code of Federal Regulations (CFR) Part 1794 National Historic Preservation Act (NHPA) Section 106
Federal Aviation Administration	Title 14 CFR Part 77, Objects Affecting Navigable Airspace
U.S. Army Corps of Engineers	Clean Water Act, Section 404/Nationwide Permit 12, Jurisdictional Water of the U.S.
U.S. Fish and Wildlife Service	Endangered Species Act, Section 7 Consultation
State	
Colorado Public Utilities Commission	Certificate of Public Convenience and Necessity (CPCN)
Colorado Department of Public Health and Environment	Construction General Stormwater Permit and Stormwater Pollution Prevention Plan (SWPPP) Section 401 Water Quality Certification
Colorado Department of Transportation	Access Permits if necessary
Colorado State Historic Preservation Office	Determination of Compliance with NHPA Section 106
Local	
Municipalities and counties	Land use, construction and crossing permits

Figure 118: Project Approvals

Source: Public Service Company of Colorado[268]

occur before the relationship takes on a formal, quasi-judicial tone, and there is an opportunity for a candid conversation about the project in question while it is still in the conceptual stage."

A range of options is available for policymakers to consider, should the decision be made to reform Colorado transmission siting and permitting.

Western Resource Advocates' *Smart Lines*[269] report states that, "Proper planning for siting new transmission lines is critically important to direct both renewable energy development and supporting transmission to the least environmentally sensitive areas in the West." The report recommends a four-step approach to balancing the goals of reliable power and environmental protection: 1) pursue energy efficiency first, 2) maximize use of the existing grid and rights-of-ways by upgrading voltage capabilities and improving efficiency, 3) connect clean and renewable energy resources, and 4) ensure long-lasting protection for public lands and wildlife resources.[270]

The current process is complicated, often requiring permits from several counties for a single project, with little or no consistency. In several instances, antiquated codes exist that certainly were not designed for today's energy markets or RPS goals and the need for carbon reduction. Some have accurately described the process as fragmented, where decision making rests with volunteer boards faced with reviewing technical projects that have benefits and impacts that go beyond their jurisdiction. The impacts include risks of height limitations, setback requirements, and undergrounding and a county level concern with any of these or other issues raises the seripous potential for major schedule delays which then in turn affect the aility to finance or complete the project, with the implication of major schedule delays that affect financing. Figure 118 illustrates several project approvals that may be needed, given certain conditions, including whether the project crosses federal land or involves federal financing.

Current processes are not tailored to successfully review complex, highly technical interconnected networks—especially linear networks that traverse multiple jurisdictions.

In short, current processes are not tailored to successfully review complex, highly technical interconnected networks—especially linear networks that traverse multiple jurisdictions. The issues referenced above are not unique to Colorado, but are intensified here because the state does, in fact, have a unique approach to transmission siting. The chart on the following page, prepared by PSCo, compares siting/permitting authorities in certain states with Colorado.

Ecological and Other Concerns

The WorleyParsons report indicates that only a few areas within Colorado's GDAs present major siting challenges so substantial that they may actually preclude renewable energy project developments. Portions of the GDA footprints encompass environmentally cautionary areas. Although development is not prohibited, it must be carefully carried out, and, in some specific areas within the GDAs, it may require transmission line rerouting and/or modification of renewable generation facilities to accommodate the constraints in other ways.

State	Does State Have Siting/ Permitting Authority?	State Agency Responsible for Siting/Permitting Review	Is State Siting Review Separate from, or Combined with, Need Certification?
Arizona	Yes	Arizona Corporation Commission	Separate
California	Yes	California Public Utilities Commission	Combined
Colorado	No	N/A	N/A
Idaho	Yes	Idaho Public Utilities Commission	Separate
Iowa	Yes	Iowa Utilities Board	Combined
Kansas	Yes	Kansas Corporation Commission	Separate
Michigan	Yes	Michigan Public Service Commission	Combined
Minnesota	Yes	Minnesota Public Utilities Commission	Separate
Montana	Yes	Montana Department of Environmental Quality	Combined
Nevada	Yes	Public Utilities Commission of Nevada	Combined
New Mexico	Yes	New Mexico Public Regulation Commission	Separate
North Dakota	Yes	North Dakota Public Service Commission	Separate
Oklahoma	No	N/A	N/A
Oregon	Yes	Oregon Energy Facility Siting Counsel	Separate
South Dakota	Yes	South Dakota Public Utilities Commission	Combined
Texas	Yes	Public Utility Commission of Texas	Combined
Utah	No	N/A	N/A
Washington	Yes	Energy Facility Site Evaluation Council	Combined
Wisconsin	Yes	Public Service Commission of Wisconsin	Combined
Wyoming	Yes	Wyoming Public Service Commission	

Source: Edison Electric Institute

Figure 119, produced for the REDI report, shows the GDAs overlaid with sensitive conservation areas that must retain their original landscape integrities because native species, communities, and ecosystems are located within it. The map demonstrates that a portion of all the GDAs contain, or are adjacent to, at least one conservation area. The map identifies low to very high conservation ratings and the locations of irreplaceable species. These ratings illustrate the probability of encountering sensitive or rare species and communities, and it indicates the potential for high, moderate, and low constraints that developers may encounter when siting generation and transmission facilities. The map also identifies areas of environmental concerns—those locations that are likely

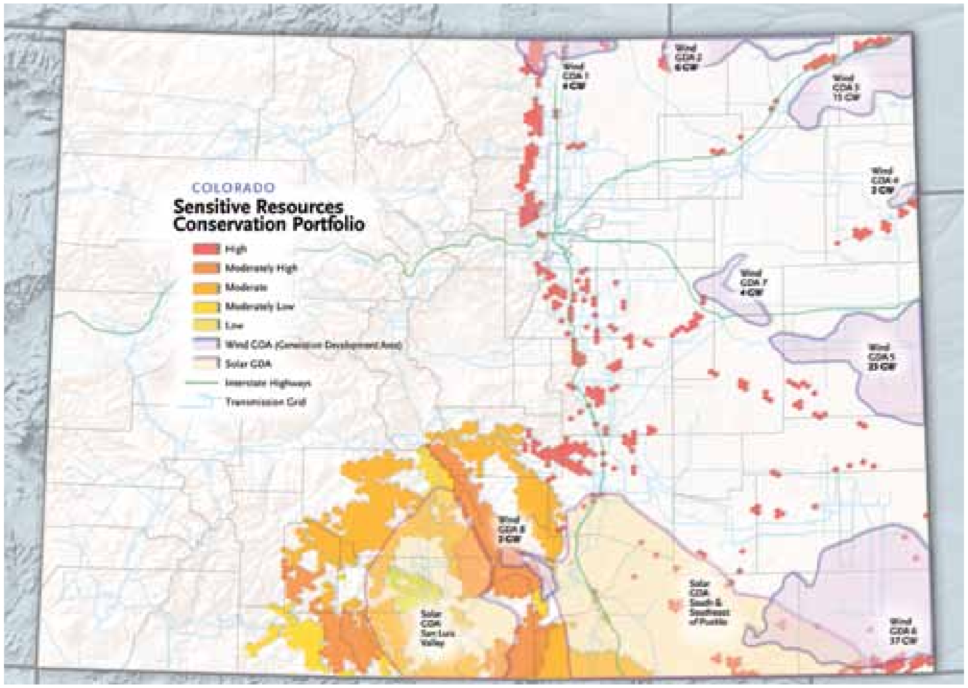


Figure 119: Sensitive Resources Conservation Portfolio Map

Source: Colorado Governor's Energy Office, REDI report[271]

to contain threatened, endangered, or globally imperiled species. In addition, it identifies communities with a high avoidance designation.

Developers recognize the need to carefully site their power plants and transmission lines. This is particularly true in areas that contain irreplaceable species or environmentally sensitive attributes. The federal National Environmental Policy Act (NEPA) requires biological and other assessments if there is a federal nexus (oversight by a federal agency, or involving federal funding). While the map could be used as an initial guide for planning, site-specific surveys are required to understand whether a facility will affect such resources. If disturbances are likely, measures must be determined to avoid or minimize such effects.

Federal Permitting

Section 368 of the Energy Policy Act of 2005 directs the secretaries of agriculture, commerce, defense, energy, and the interior to designate, under their respective authorities, corridors on federal land in 11 western states (including Colorado) for oil, gas, and hydrogen pipelines and electricity transmission and distribution facilities (energy corridors). The law requires that these departments conduct any necessary environmental reviews to complete the designation of Section 368 energy corridors. Various federal agencies have different requirements and processes, and it is possible that a project may require coordination with one or more federal agencies.

State and Local Government Permitting

The law firm of Holland and Hart's report, *Transmission Siting in the Western United States: Overview and Recommendations Prepared as Information to the Western Interstate Energy Board*,[272] summarizes Colorado siting requirements as follows: "The siting and approval of a major transmission project in Colorado by a public utility is within the regulatory purview of the Colorado Public Utilities Commission." Colorado courts have held that the key factor in the definition of "public utility" is whether the facility supplies utility services "to the public," and that such a certificate is not required if the entity provides utility services to only a limited group of customers. In addition, a certificate is not required for construction, operation, or extension of a facility "in the ordinary course of business." A major transmission project that is constructed in Colorado and contains interconnections to other transmission or distribution systems that serve load in Colorado would likely need a certificate from the Colorado PUC.

Along with supplying the required technical information and design details, an applicant for a certificate of public convenience and necessity (CPCN) for construction or extension of transmission facilities is required to describe how it will achieve "prudent avoidance" or strike "a reasonable balance between the potential health effects of exposure to magnetic fields and the cost and impacts of mitigation of such exposure. The scope of public interest or need is generally left to the discretion of the PUC."[273] The PUC recently revised its CPCN rules to require utilities to meet certain noise level and magnetic field level targets.

Local Governments

A county or city typically will approve a transmission line by issuing a special or conditional use permit (a "use permit"). If denied, an applicant (the utility) may appeal the decision if 1) the applicant has applied to the PUC for a CPCN; 2) such a certificate is not required; or 3) the PUC has issued an order that conflicts with the local government's action. In considering an appeal from a local decision, the PUC is required to consider the demonstrated need for the facility, the extent that it is inconsistent with local land-use plans and ordinances, and whether it would "exacerbate" a natural hazard. [274]

1041 Regulations

Colorado cities and counties are authorized to regulate by permit activities within certain areas of state interest. These permits are commonly referred to as "1041 permits" because the statute was enacted in 1974 as HB 1041. The 1041 process is applicable to "major facilities of a public utility," defined to include transmission lines and substations.[275]

County permitting processes vary within the areas of Colorado that are in a GDA, or would be served by a transmission to connect a GDA. In general, county permitting procedures for power plants (renewable and nonrenewable), transmission lines, and substations use a 1041 permit, a use by special review permit, a conditional use permit, or a land-use permit. The permitting requirements are fairly similar, although the 1041 permit application typically is more comprehensive.[276]

"The FERC oversees and approves interstate gas pipeline land use, with preemptive powers over private property. The FERC, however, has not exercised similar jurisdiction when it comes to electric transmission. Changes to this double standard warrant serious consideration."

Environmental Impact Assessments

Transmission developers can be required to consult with the Colorado Department of Wildlife (CDOW) before submitting siting permit applications to local government authorities. CDOW could then begin conducting an environmental impact assessment (EIA) of the proposed transmission project earlier in the process. EIAs can be a major component of the permitting process, since they are required by some counties and encouraged by others. An EIA study often includes an avian and bat study for wind farm developments, which may take between eight and 12 months to complete. Although an EIA is not always required for a new transmission project, many local jurisdictions require, or at least recommend, an EIA as a condition of receiving the necessary permits. Some counties formally request that CDOW comment on permit applications, leading the department to require an EIA. Completing an EIA is often the most time-consuming part of the application process. Requiring transmission developers to initiate an EIA via consultation with CDOW may increase costs if jurisdictions where a line is proposed do not require an EIA for permit approval. However, if an EIA is required, early consultation speeds the process.[277]

Acquiring Rights on Private Lands

The Western Area Power Administration's guidance document, *Working with Landowners*,[278] describes the process for acquiring permission to use private lands for transmission. The document details how companies building transmission facilities obtain easements and how utilities identify a transmission line corridor, including proposed sites for transmission towers and transmission tower designs. If the negotiation process breaks down, easements can be acquired through eminent domain (condemnation) proceedings. A large amount of land in Eastern Colorado is privately owned, so negotiations with private landowners are required to build most of the anticipated new renewable generation and transmission in the state.

Opportunities on the Colorado State Board Land Commissions' Property

HB 07-1145 was signed by Governor Ritter on April 26, 2007. The law encourages the Board of Land Commissioners to identify state-owned land for development of renewable energy resources. It encourages the board to collaborate with the GEO and other state and federal agencies to promote use of state land for renewable energy development, but to minimize impact to the land. The Board of Land Commissioners issues renewable energy production leases and planning leases.[279]

Federal Activities

In addition to the many energy and environment policy changes under way, the federal context is particularly important to Colorado, given that more than 36 percent of the state's land is under federal control. The Department of the Interior has several initiatives under way, including an order that sets aside 676,000 acres of federal land for study and environmental reviews as potential sites for deploying renewable energy. A detailed description of these and other federal initiatives is contained in the REDI report.

The FERC oversees and approves interstate gas pipeline land use, with preemptive powers over private property. The FERC, however, has not exercised similar jurisdiction when it comes to electric transmission. Changes to this double standard warrant serious consideration.

Proposals under Consideration to Streamline the Permitting Process

One suggestion under consideration to streamline the transmission permitting process in Colorado is to establish a statewide task force on transmission siting and permitting to make findings and recommendations to the governor and the General Assembly. The task force would hear testimony on a range of topics that might include: 1) the advantages and disadvantages of a state-level transmission permitting framework for transmission and generation facilities; 2) an inventory and evaluation of Colorado's current permitting structure—considering benefits and shortcomings; 3) research examples of how other states approach siting approvals for transmission and generation development; and 4) identification of possible models for improving Colorado's existing permitting processes. The task force might consider public comments received during the public hearing process, as well as written comments from affected counties, cities, electric providers and customers, environmental groups, and other interested stakeholders.

Holland and Hart's report summarizes best practices for siting and permitting: "In our review of the foregoing state regulatory requirements for siting a major transmission facility in the West, we identified a number of 'best practices' that could serve as integral elements of a regional siting regime. These 'best practices' include:

- State siting agency preemption of conflicting local decisions, at the same time using a process to ensure that local community concerns are considered and that a local decision is overridden only if the broader public interest is compelling.
- A centralized siting agency with jurisdiction over transmission projects proposed by any entity, whether or not the proponent is a regulated public utility.
- A definition of 'need' that recognizes the critical public interest in the reliable and efficient transmission of electricity from a diverse portfolio of generation sources in one part of the region to growing load centers in another, even if neither the generator nor the loads to be served are located within the state.
- Mechanisms to facilitate participation in regional and national transmission planning regimes to ensure coordination and the most efficient use of resources in the construction of new transmission facilities.
- Regular, periodic planning to assess strategic needs for transmission infrastructure and to ensure that proposals are consistent with those needs.
- Timelines that are long enough to ensure thorough review of a proposal but short enough to ensure that a decision is issued within a reasonable period of time.
- Accelerated reviews for projects in designated corridors, including NIETCs designated under the Energy Policy Act of 2005 and other corridors designated pursuant to state, regional, and federal plans.
- A level regulatory playing field that does not favor investor–owned utilities or any other entities at the expense of other transmission developers."

Approving the site for lateral transmission lines, including a determination whether there is a "need" for a line and authorization for public utilities to use eminent domain under state law, is a traditional state role. States already regulate most transmission-related revenues, and in many states merchant transmission providers do not qualify as public utilities. In 2005, Congress gave FERC limited "backstop" siting authority if projects were proposed in certain corridors. However, this backstop siting authority has not been exercised. The challenge is to determine whether the interstate nature of the modern bulk power market and new RES policies suggest a stronger role for federal siting or regional compacts.

Conclusion

The issue of siting and permitting for new transmission is viewed by many as being as difficult as transmission planning and financing. There is a growing understanding that Colorado's transmission permitting system may need to be more streamlined and better coordinated. Effective transmission siting and permitting addresses protection of many interests, including concerns of property owners, environmental considerations, and local governments. Input from these concerns should be addressed in a more timely fashion to ensure that progress occurs; protracted litigation has proven that it can stymie expansion of the state's high-voltage transmission infrastructure.

Colorado policy-makers should consider whether the current structure for permitting transmission places the state at risk of slowing the transition to a clean energy and more reliable electricity sector. If the risk is determined to be substantial, appropriate legislative solutions should be crafted.

16. The Potential for Independent Transmission Companies

REDI Review

Independent transmission companies (ITCs) are a relatively new class of transmission owners and operators. Precluded by a 1999 FERC policy from participating in power markets, ITCs focus solely on transmission, sometimes competing with, and other times assisting, traditional utilities to promote transmission options to meet reliability and delivery requirements. One general theme of FERC's efforts in transmission policy includes eliminating barriers to entry of independent and other nontraditional utility investment.

Transmission competition is limited in Colorado because no provisions exist for ITCs in Colorado statute, or within PUC regulations. Colorado would benefit by determining whether its utility statute or should be amended to craft terms and conditions for the entry of ITCs in the state transmission market.

Overview

Transmission expansion historically has been driven primarily by load growth and the need for greater system reliability. Well-established and well-defined processes for transmission planning are based upon clear criteria, such as reliability performance standards and commonly accepted formulas for evaluation. Increasingly, however, transmission projects also are screened against a broadening set of criteria, such as relieving congestion and increasing the penetration of renewable energy on the grid.

As the drivers for transmission development have evolved and expanded, so, too, have the types of developers, owners, and operators. Historically, virtually all high-voltage transmission built in the United States was planned, financed, designed, and constructed by electric utilities and federal hydro marketing authorities such as the Western Area Power Administration. A relatively new arrival in the market is the ITC. Although at this juncture comparatively few transmission lines have been built by ITCs,[280] such projects are growing in strength and number, and have helped to solve certain critical issues, including:

- Relieving congestion, and thereby lowering prices paid by electric customers
- Improving reliability
- Providing access to new capital
- Supporting renewable objectives and RPS requirements

The Wyoming-Colorado Intertie Project

The Wyoming-Colorado Intertie Project (WCIP) is a proposed new 345-kV transmission project that is envisioned to stretch approximately 180 miles between the Laramie River Station substation located near Wheatland, Wyoming, and the Pawnee substation located near Brush, Colorado. As envisioned, the project would provide 850 MW of firm transmission service across the TOT3 constraint located at the Wyoming-Colorado border.

National Trends for Independent Transmission Companies

On Feb. 19, 2009, the FERC issued an order authorizing two independent transmission developers, Chinook Power Transmission LLC and Zephyr Power Transmission LLC, to deliver power from wind generation in Montana and Wyoming to electric customers in the Southwest.[281] The developers sold transmission rights at negotiated rates without allocating 100 percent of the initial transmission capacity through an open season process. This FERC order marks an evolution in the commission's policy because it allows independent transmission developers, for the first time, to subscribe transmission capacity to an "anchor" customer before the open season process. Also of note is the fact that, in evaluating the requests of Chinook and Zephyr for negotiated rate authority, the commission adopted a new streamlined four-factor analysis.

In the past, the FERC, citing fairness and transparency concerns, had required independent transmission owners to allocate 100 percent of initial capacity through a preconstruction open season. Now, in light of commercial realities and recognition of the fact that the financial commitments made by anchor customers before an open season provide crucial and early support and certainty to independent transmission developers, the commission will entertain proposals to allocate all or a portion of initial capacity outside an open season on a case-by-case basis. It also will allow anchor customer allocations, provided that the commission is satisfied that the transmission developer has not acted in an unduly discriminatory manner in allocating capacity. FERC previously evaluated requests by independent transmission developers for negotiated rate authority using a ten-factor analysis.

In the future, the commission will use the following more adaptable four-factor analysis to review requests for negotiated rate authority based on the following criteria.

- **Just and Reasonable Rates:** The commission will consider whether the transmission developer has assumed the full market risk of the development or whether it is developing the project in an area where it has captive customers.
- **Undue Discrimination:** The commission will continue to rely on the post open season report and complaint process to ensure fairness in initial capacity allocations. As discussed, FERC no longer will require that all initial capacity be allocated through an open season. Transmission developers will be required to create firm, tradable secondary transmission rights and to create and maintain an open-access, same-time information system (OASIS) for customers to purchase and sell these rights.
- **Undue Preference and Affiliate Concerns:** The commission will apply a higher level of scrutiny where a transmission developer allocates initial capacity—either through a presubscription or through the open season process—to customers affiliated with the transmission developer.
- **Regional Reliability and Operating Efficiency:** The commission encourages independent transmission developers to turn over operational control of their facilities to RTOs or ISOs, where available, and in all cases will require compliance with all applicable NERC standards and those of any regional reliability council.

Statements by commissioners suggest that the FERC also may have viewed use of these projects to connect renewable resources to markets as a key consideration.

Several New Entrants are Filling the Need for More Transmission

Although many projects have been announced, to date, independent transmission has had modest success. In the PJM Interconnection, for example, 77 independent transmission lines have been proposed since 2001; 60 percent of them have been withdrawn, and only nine projects (12 percent) are now in service.[282] See Figure 120. Financing an independent power line is difficult, and many banks have shied away from doing so, especially during the recent credit crisis. Thus, part of the independent transmission story is the lack of deals. However, nonconventional sources of capital such as private equity, infrastructure funds, and hedge funds now are targeting independent transmission line projects.

Independent transmission appears to have an important and growing role in expanding and modernizing the nation's transmission infrastructure; the full potential has yet to be realized, however. Experience shows that regulatory hurdles and financing challenges are the primary obstacles to independent transmission projects. As these issues are addressed, independent transmission and related infrastructure could obtain the necessary critical expansion and upgrades.

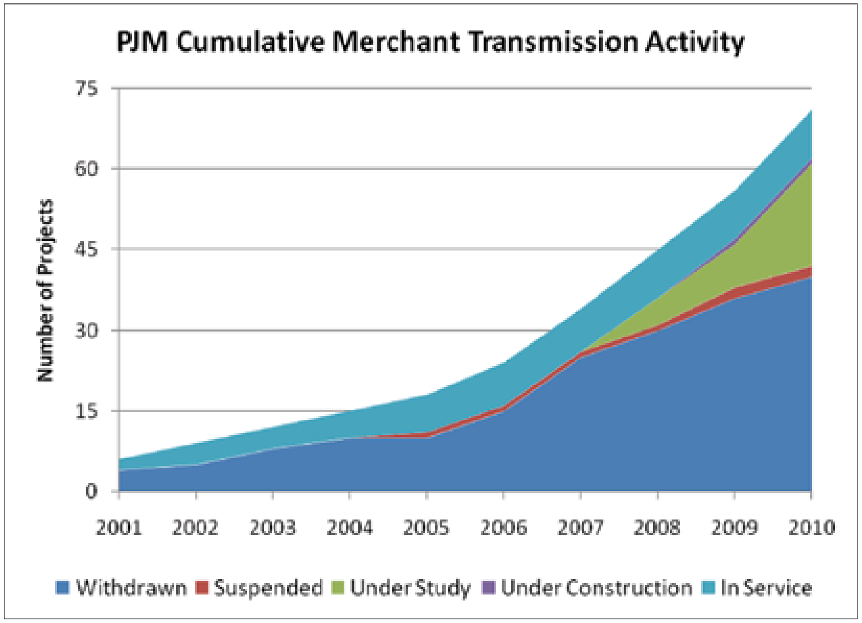


Figure 120: PJM Cumulative Merchant Transmission Activity

Source: ION Consulting analysis of PJM[283]

Texas and Competitive Renewable Energy Zones

The Texas Legislature passed Senate Bill 7 in 1999, which restructured a significant portion of the state's electric industry and allowed transmission service providers (TSPs) to offer services to other utilities throughout the portion of the Texas electric grid operated by ERCOT.

In 2005, Senate Bill 20 established the Texas renewable energy program and directed the PUC to identify Competitive Renewable Energy Zones (CREZs).[284] A CREZ is a geographic area with optimal conditions for the economic development of wind power generation facilities. In response to this legislative action, the PUC issued a final order in 2008, establishing five Competitive Renewable Energy Zones in Texas and designating a number of transmission projects to be constructed to transmit wind power from the CREZs to the highly populated metropolitan areas of the state.[285] The completed CREZ transmission projects will eventually add 2,400 miles of 345-kV transmission to the ERCOT grid, capable of transmitting approximately 18, 500 MW of wind power.

A number of transmission lines designated as priority CREZ projects also will provide transmission infrastructure necessary to meet the long-term needs of the growing area west of the I-35 corridor between San Antonio and Killeen. In addition, more wind energy will be brought to customers, which will displace some need for sources of electrical generation that cause carbon and other emissions, such as coal and natural gas, and will further diversify the fuel portfolio of Texas generation resources.

Three categories of CREZ projects were identified in Docket No. 33672.

- Default projects are those that refit, rebuild, or enhance existing transmission infrastructure. The CREZ default projects were awarded to the TSPs that owned the existing infrastructure. A number of the CREZ default projects have been completed, and others are in various stages of completion.
- Priority projects are those that were identified as necessary to alleviate current or projected transmission congestion issues and were determined to have the highest priority for completion. The CREZ priority projects were awarded to two incumbent utilities, Oncor Electric Delivery LLC (Oncor) and LCRA Transmission Services Corporation (LCRA TSC).
- Subsequent CREZ projects consist of the remaining CREZ transmission projects not identified as either default or priority.

Despite significant landowner agitation, only once CREZ line– a 95 mile segment between the Newton and Gillespie substations– appears unlikely to be built. The Texas PUC rejected LCRA's application for that line because of concerns over route adequacy, and ERCOT subsequently announced that the line could be excluded from the CREA plan if existing 138 kV lines in the vicinity were significantly upgraded. [286] [287]

Ten designated TSPs are seeking to construct, operate, and maintain the CREZ-related transmission projects. For most projects (excluding most, if not all, of the default projects) the TSPs must complete a certificate of convenience and necessity (CCN) application and obtain approval through a public process. Three of the ten designated TSPs are ITCs; a fourth previously served only a 10-square-mile transmission service territory; and a fifth is a joint venture of a longtime TSP and MidAmerican. The ten TSPs are listed below and shown in Figure 121.

- **Cross Texas:** Cross Texas Transmission will construct, operate, and maintain more than 200 miles of double circuit 345-kV transmission lines and associated equipment generally located in the Texas Panhandle.
- **ETT:** Electric Transmission Texas LLC is a joint venture between subsidiaries of American Electric Power and MidAmerican Energy Holdings Company. ETT acquires constructs, owns, and operates transmission facilities within ERCOT, primarily in and around the AEP Texas Central Company (TCC) and AEP Texas North Company (TNC) service territories.
- **LCRA TSC:** LCRA TSC is an existing ERCOT transmission utility that began operations in 2002 as a successor in interest to the transmission business unit of the Lower Colorado River Authority (LCRA). LCRA owned and operated its transmission system

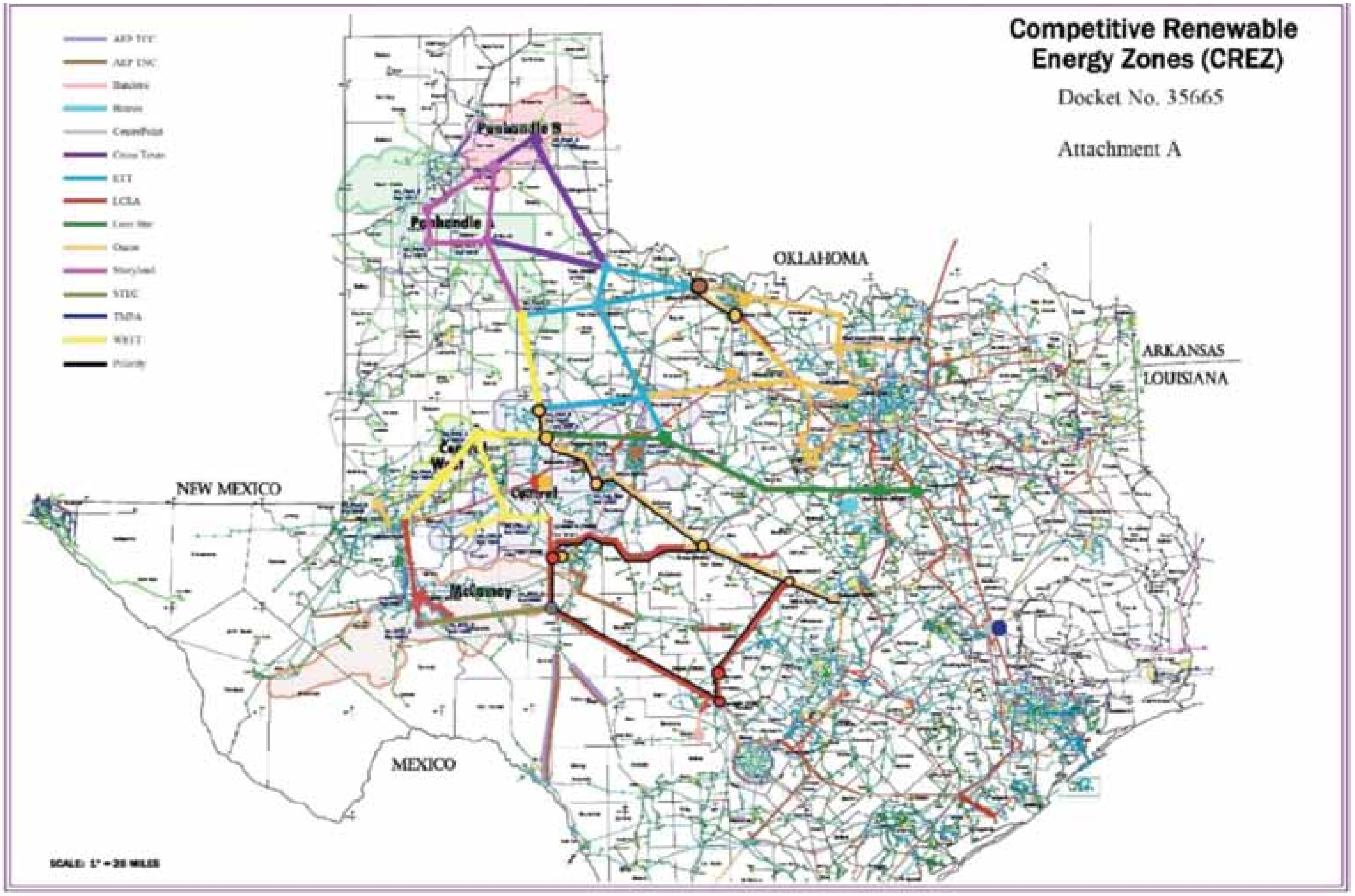


Figure 121: Texas CREZs
Source: Public Utilities Commission of Texas

for more than 60 years, receiving its certificate of convenience and necessity (CCN No. 30110) from the Public Utility Commission of Texas (PUCT) in 1978. In 2001, the PUCT authorized transfer of the LCRA transmission system and its CCN to LCRA TSC.

- **Lone Star:** Lone Star Transmission is a new entrant and a subsidiary of NextEra Energy Inc.; it will construct, own, and operate more than 300 miles of CREZ transmission facilities within Texas.

- **Sharyland:** Sharyland Utilities LP is a Texas-based public transmission and distribution electric utility. Its current service territory is located along the Rio Grande border in the South Texas cities of Mission and McAllen. Sharyland Utilities is privately owned and managed by Hunter L. Hunt and other members of the family of Ray L. Hunt.

- **Brazos:** Brazos Electric is a 3,000 MW generation and transmission cooperative. Its members' service territory extends across 68 counties from the Texas Panhandle to Houston. Brazos has no active CREZ projects at this time. It is the largest generation and transmission cooperative in the state. Brazos Electric is the wholesale power supplier for its 16 member-owner distribution cooperatives and one municipal system.

- **Bandera:** Bandera Electric Cooperative Inc., member-owned since 1938, serves the Texas counties of Bandera, Bexar, Kendall, Kerr, Medina, Real, and Uvalde. Bandera has no active CREZ projects at this time.
- **STEC:** South Texas Electric Cooperative (STEC) was formed in 1944 to provide wholesale electric power to member cooperatives. The STEC presently serves eight distribution cooperatives. These cooperatives provide service to more than 170,000 members in 65 South Texas counties. STEC has three named CREZ projects at this time.
- **WETT:** Texas-based Wind Energy Transmission Texas LLC (WETT) is a new entrant and joint venture between Brookfield Asset Management and Isolux Corsan Concesiones SA.
- **Oncor:** Oncor Electric Delivery Company LLC (Oncor) is a regulated electricity distribution and transmission business. Oncor operates the largest distribution and transmission system in Texas, delivering power to more than 3 million homes and businesses and operating approximately 117,000 miles of transmission and distribution lines in the state. Oncor is owned by a limited number of investors, including majority owner Energy Future Holdings Corp.

ITC Projects in Other States

A number of other projects have successfully addressed local transmission problems in other states, including the following.

- **Cross-Sound Cable (CSC):** The first independent transmission project to come online in the United States, Cross-Sound Cable was developed by TransEnergie, a subsidiary of Hydro-Quebec. The HVDC transmission project moves 330 MW of power from Connecticut to Long Island via a 24-mile-long submarine cable buried in Long Island Sound. It was completed in June 2004. The CSC provided direct access to low-cost power from PJM Interconnection and New England and significantly improved reliability.
- **Montana Alberta Tie Line (MATL):** A 214-mile, 230-kV transmission line that will interconnect the electricity markets of Alberta and Montana, the Montana Alberta Tie Line will allow much-needed energy flow in both directions, ensuring more reliable supplies of electricity. In addition to making both regions less vulnerable to power outages, the line also will enable development of new wind-energy projects by interconnecting new wind developments in the area. MATL is fully permitted, and construction is expected to be completed in mid-2011.
- **Neptune Project:** A 65-mile undersea and underground HVDC transmission line, the Neptune Project extends underwater and underground from New Jersey to Long Island. Neptune provides up to 660 MW of power to Long Island electricity customers and supplies more than 20 percent of Long Island's typical electricity demand. Neptune began construction in June 2005 and was completed in June 2007. It operates under a long-term agreement with the Long Island Power Authority (LIPA), which selected Neptune RTS to build and operate the project in a competitive solicitation in 2004.
- **Juan de Fuca Cable Project (JDF Cable)**: A 550-MW HVDC submarine electric transmission line, JDF Cable will connect the Greater Victoria area of British Columbia with Port Angeles, Washington. The JDF Cable will be a 30-mile bidirectional line that connects and strengthens the westerly endpoints of both the British Columbia and Washington transmission grids. Because Port Angeles and Victoria each are at the ends of radial transmission lines, they are more vulnerable to electrical outages. The JDF Cable will provide additional reliability and stability for both Vancouver Island and the Olympic Peninsula. The project has been under development since 2003 and is fully permitted. It is now in the last phase of project development, and negotiations for system benefits and the reservation of transmission capacity on the line are under way.

Conclusion

By many accounts and for a variety of reasons, questions are raised about whether transmission infrastructure is developing at a pace that will meet Colorado's opportunities.

As stated in the REDI report, transmission competition is limited in Colorado because no provisions exist for ITCs in Colorado statute, and within PUC statutes. One suggested potential public policy option would amend Colorado's utility statute (Title 40) to allow ITC entry, providing the ITCs with a more open opportunity to compete in the Colorado electric power marketplace.

Some potential opportunities for ITCs could arise, as they may have a greater threshold for risk. The ITCs might be more inclined to install higher voltages, which are a significant need in Colorado to reinforce the eastern end of the Western Interconnection, and to be a partial pathway for eventual export of renewables aligned with the objectives of the High Plains Express. ITCs also might be willing to accept greater risks if certain state regulatory risks could be resolved. It has been reported that billions of dollars of equity are available nationally to provide the capital to help build transmission assets. A certain risk exists that, if changes to the status of ITCs in Colorado do not take place, independent transmission developers may continue to concentrate on developing opportunities in states where regulations and policies are more receptive to their business model.

Entry of ITCs will not resolve the majority of the many transmission challenges. However, opening the transmission enterprise to competition warrants investigation. The most significant risk that concerns ITCs is the state regulatory environment. Further discussions should be explored to determine the rules and regulations under which ITCs should operate. This could potentially be accomplished by amending Colorado's utilities statutes or amending certain PUC regulations.

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