CDEAC Transmission Task Force Draft Report 11-30-05

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EXECUTIVE SUMMARY

Developing the generation resources identified by the Clean and Diversified Energy Advisory Committee (CDEAC) recommendations will require the West to improve the use of the existing transmission system and expand the grid to deliver power from these largely remotely-sited resources to customers in load centers. This will require the collaborative effort of many parties. Western Governors can be an effective catalyst to initiate needed action.

The Transmission Task Force examined the transmission needed to move the postulated clean and diversified energy resources to consumers. There are many uncertainties in estimating what transmission additions are required. Looking out to 2015, the Task Force estimates that additional transmission needed in the WGA States in the Eastern Interconnection is in the range of $__ billion dollars, in the Electric Reliability Council of Texas (ERCOT) $___ billion, and the Western Interconnection $__ billion dollars. While relatively large, transmission costs are less than 10 percent of the cost of the power delivered to customers. Implementation of the recommendations of the Efficiency Task Force can lessen the need for some new transmission investment. The evaluation of transmission needs is not a one-time process. Changing circumstances require an on-going robust transmission planning process that continually reassesses the uncertainties inherent in long-term transmission planning.

To ensure adequate transmission for the region to tap its vast clean and diversified energy resources, Western Governors should adopt and take necessary steps to implement the following actions. The recommendations are grouped according to federal, regional, state, and local entities and industry that would implement the recommendations. Background and the full text of the recommendations are in Section II.

1. FERC's ongoing review of its open access transmission policy under Order 888 provides an excellent venue to urge the Federal Energy Regulatory Commission to make needed reforms. The Western Governor's should engage the Commission to make changes to its transmission policies to:
    a. Promote a conditional-firm and related new transmission tariff product (Recommendation #1);
    b. Encourage transparent review and assessment of available transfer capability (ATC) levels (Recommendation #2);
    c. Eliminate rate pancaking (i.e. access fees imposed on transmission customers contracting for service across multiple control areas) in the transmission system (Recommendation #3);
    d. Promote control area consolidation (Recommendation #4);
    e. Encourage congestion management systems that allow access to least-cost generation within reliability security constraints (Recommendation #5);
    f. Encourage common OASIS sites to facilitate transmission transactions (Recommendation #6);

   g. Clarify code of conduct rules for utilities to enable transmission staff and resource planners to participate in open public transmission planning forums (Recommendation #7e); and
   h. Request that FERC convene a technical conference to develop needed reforms of interconnection and transmission queuing processes (Recommendation #9).

2. The Western Governors should take an active leadership role to promote state and regional policies in collaboration with state legislatures to:
   a. Ensure resources to enable state participation in regional transmission planning (Recommendation #7a);
   b. Encourage the electric power industry to make the existing pro-active, transparent interconnection-wide and sub-regional transmission planning processes a priority (Recommendations #7a);
   c. Review, and if necessary, amend state laws to require PUCs and public power boards to consider regional transmission needs (Recommendation #7b);
   d. Support the goal of a regional planning capability that can yield critical information for stakeholders and regulators to allow rigorous evaluation of large long-term investments in transmission (Recommendation #7c);
   e. Bring together stakeholders and forge solutions to regional transmission needs, cost allocation, and siting where RTOs/ISOs do not exist and ensure state participation in such activities by existing RTOs/ISOs (Recommendation #8);
   f. Promote use of an open season process by project developers as a means of demonstrating demand for and value of new transmission projects, and expand project participation (Recommendation #10);
   g. Urge FERC and PUCs to form joint panels on transmission cost recovery that would explicitly consider risks and needs for incentives such as forms of pre-approval, higher rates of return on transmission investments, and quicker cost recovery of transmission investments (Recommendation #15);
   h. Urge transmission operators to develop workable agreements at seams between ISO and non-ISO systems to enable effective grid operations (Recommendation #17);
   i. Ensure that there are resources and political commitments to successfully implement the WGA Transmission Permitting Protocol and the Midwest Electric Transmission Protocol for new interstate transmission proposals (Recommendation #18a);
   j. Evaluate the option of forming an interstate compact for creation of a regional siting agency pursuant to Section 1221 of the Energy Policy Act of 2005, and encourage consistent siting processes within their state through use of standardized applications, joint data and studies, coordinated schedules and deadlines, and other mechanisms, where possible (Recommendation #18b, 18c).

3. The Western Governors should urge state public utility commissions to adopt policies, and promote legislation, if necessary, to:
    a. Establish tiered standards of review for prudency and application of transmission incentives for transmission expansion costs featuring a lower standard for screening studies and planning, a moderate standard for permitting and the acquisition of rights-of-way, and a higher standard for construction costs (Recommendation #11);
    b. For states with mandatory renewable portfolio standards, regulatory commissions should make public interest findings associated with cost effective transmission projects that will enable states to attain energy policy goals (Recommendation #12);
    c. Expand transmission in advance of generation to enable the modular development of location-constrained, clean and diversified resource areas to meet cost-effective RPS, IRP and state goals, similar to recent Texas and Minnesota legislation for new transmission and the renewable trunk line (Tehachapi) model for new transmission (Recommendation #13);
    d. Coordinate multi-state review of transmission projects by developing common principles for cost allocation and cost recovery, and adopt a common western procedural process that would identify and coordinate the applications, forms, analyses and deadlines (Recommendation #14);
    e. Promote cost-effective transmission expansion by accommodating both non-dispatchable and dispatchable resources.

4. Western Governors should collaborate with the appropriate federal agency to implement the Energy Policy Act provisions to designate energy corridors on federal lands by:
    a. Committing state agency resources to participate in the federal effort and to identify contiguous corridors on adjacent state lands (Recommendation #19);
    b. Urging Congress to fund federal land management agency corridor planning efforts (Recommendation #19);
    c. Fostering designation of corridors on lands not owned by the federal government or the states to ensure continuity in corridors. Designation and preservation of transmission corridors is important in rapidly urbanizing parts of the region (Recommendation #19).

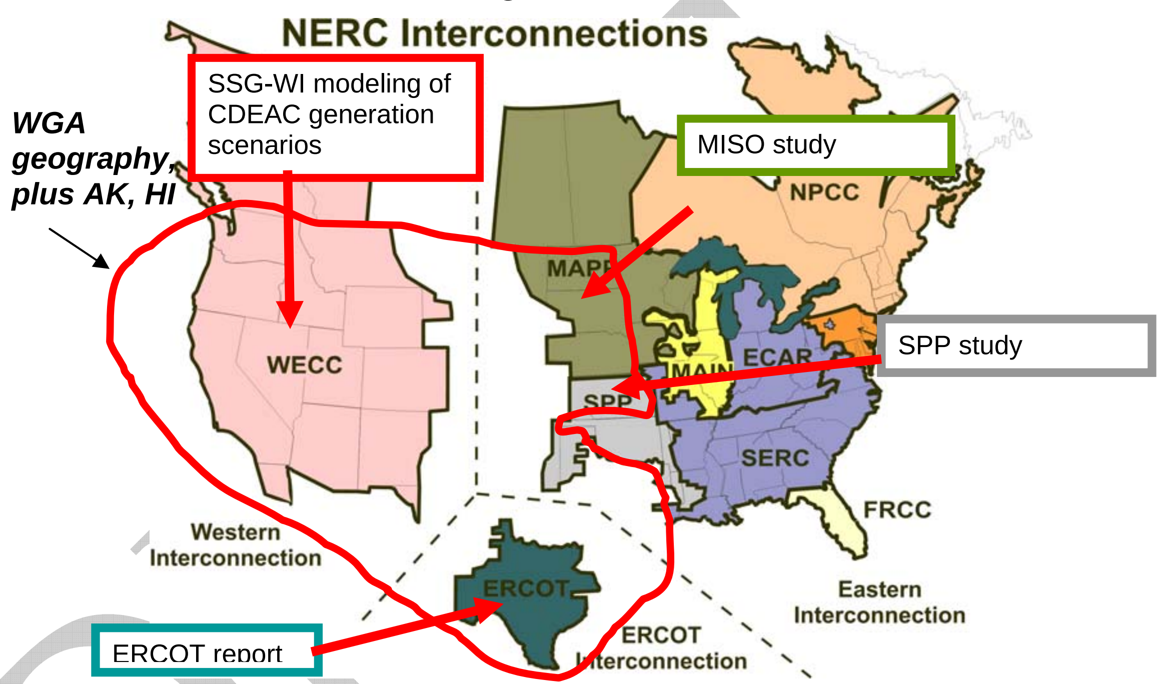
5. Western Governors should encourage the Western electric power industry to:
    a. Synchronize regional transmission planning efforts to resource acquisition plans of load serving entities (LSE) and plans of generators (Recommendation #7d);
    b. Support and collaborate with state infrastructure authorities that have been created to facilitate transmission expansion (Recommendation #16);
    c. Ensure institutional homes for regional transmission planning (Recommendation #7a)

Section I of this report examines transmission needed to move the clean and diversified resources identified by CDEAC to markets. Section II discusses important issues and policy recommendations for the efficient use and expansion of the transmission system.

I. TRANSMISSION OPPORTUNITIES TO SUPPORT CDEAC GENERATION

The Task Force finds that even with improvements in operation of existing transmission grids, new transmission will be needed to move CDEAC's postulated new clean and diversified generation to markets. The following map shows that the geography of the WGA region spans all three interconnections in North America, as well as Alaska and Hawaii.

Figure 1



To estimate the transmission requirements to move the postulated clean and diversified energy resources to market, the Task Force used existing studies by the Midwest Independent System Operator (MISO), the Southwest Power Pool (SPP), the Texas Legislature and the Electric Reliability Council of Texas (ERCOT) for the eastern part of the WGA region. In the Western Interconnection, the transmission needs associated with scenarios identified by the CDEAC Integration Subcommittee was modeled using a production cost model and compared with a reference case developed by the Seams Steering Group-Western Interconnection. No estimates of transmission needs were made for Alaska or Hawaii.

A. TRANSMISSION IN THE EASTERN INTERCONNECTION AND ERCOT

Based on existing studies by the Midwest Independent System Operator, the Southwest Power Pool and the Texas Legislature, the Task Force believes it is technologically feasible to expand the transmission system to support the levels of clean energy contemplated to be developed by the CDEAC fuel task forces.

MISO. The MISO Transmission Expansion Plan 2003 (MTEP-03)[1] evaluated transmission to support a high wind generation scenario of 8,640 MW and additional coal generation across nine Midwestern states, including 2,900 MW in North Dakota and 2,900 MW in South Dakota. The MTEP-03 analysis examined two plans that generally reduced constraints at key bottleneck locations in the region, and improved capacity utilization of wind and coal generators. The annual levelized cost of the two transmission plans ranged from $132 to $379 million. Benefits of reduced energy costs from new transmission and development of new wind generation of the high wind scenario were between $444 and $478 million under high natural gas price assumptions ($5.00/million Btu in $2001), and $303 to $316 million under a reference case gas price assumptions ($3.34/million Btu in $2001). An alternative high coal/balanced scenario yielded benefits between $1,166 million and $1,197 million under high natural gas price assumptions.

SPP. The SPP's Kansas/Panhandle Expansion Plan examined multiple transmission scenarios to export 2,500 MW of wind energy and 600 MW of coal energy out of the SPP system from Kansas and the Texas Panhandle.[2] Two alternative plans with several new 345 kV lines ranged from $458.7 million to $477 million. Annual production cost savings for the two plans were estimated at $60 and $72 million. Over ten years, the preferred plan yielded savings of $490.7 million.

ERCOT. A joint industry and ERCOT White Paper[3] evaluated the transmission needed to support significant increases of renewable energy across Texas. The Texas White Paper examined transmission to meet two goals: (1) 3,641 MW of new wind energy in West Texas; and (2) 8,641 MW of additional wind energy throughout Texas across both ERCOT and SPP regions. For the first goal, the White Paper proposed a plan to build a series of 345 kV upgrades in West Texas deliver 3,641 MW of wind energy at a cost of $1.0 billion for transmission expansion. For the second goal, two different options were evaluated to develop 8,641 MW of additional wind energy. One option contemplated a series of 345 kV upgrades in ERCOT, a new 345 kV loop in SPP, and a new DC tie or switchable facilities to connect ERCOT and the Panhandle region of SPP. Total cost for the first option is between $1.7 and $2.1 billion. The second transmission option entails a 765 kV line along with 345 kV additions that would cost from $2.5 to 3.0 billion.

[1] Midwest ISO Transmission Expansion Plan 2003, June 19, 2003, (**Error! Main Document Only.**).
[2] The SPP website provides information the Kansas/Panhandle Expansion Plan at http://www.spp.org/Objects/Engineer.cfm.
[3] Transmission Issues Associated with Renewable Energy in Texas, Informal White Paper for the Texas Legislature, 2005, March 28, 2005. http://www.ercot.com/AboutERCOT/TexasRenewableWhitePaper2005/RenewablesWhitePaper.htm

B. TRANSMISSION IN THE WESTERN INTERCONNECTION

To provide CDEAC with insights into the transmission system in the Western Interconnection to support potential generation, several scenarios were postulated:

- High efficiency scenario;
- High renewables scenario;
- High clean fossil scenario; and
- A mixed scenario of high efficiency, high renewables scenario with some advanced gasification and sequestration.

Postulated locations of wind, solar, geothermal, biomass, and advanced fossil facilities were provided by the CDEAC task forces.

Key findings of those studies are summarized below. TO BE ADDED FOLLOWING COMPLETION OF MODELING

C. LONG TERM OUTLOOK

1. Transmission Adequacy Beyond 2015

Determining the adequacy of transmission must be the product of an on-going process that regularly reassesses uncertainties such as the economics of alternative generation technologies, fuel costs, the preferred location for generation, changes in demand, and new transmission technologies. The further into the future one attempts to look, the greater these uncertainties. Thus, the Task Force recommends that the Governors encourage industry and regulators to maintain a robust on-going process for evaluating transmission needs that systematically reexamines these uncertainties. Most long-term transmission planning looks at most 10 years into the future because that provides sufficient time to construct needed transmission.

The Task Force observes that transmission investments typically continue to provide value even as conditions change. For example, transmission originally built to the site of a now obsolete power plant continues to be used since a new power plant is often constructed at the same location. The Task Force also believes it is important to identify and preserve transmission corridors in advance of urban development. Adding transmission in developed urban and suburban areas is extremely difficulty and costly. Similarly, preservation of corridors to energy rich geographic areas with location-constrained resources, such as areas with good wind or geothermal resources, is important to assuring future transmission adequacy. Finally, the Task Force observes that transmission costs are a small fraction (less than 10 percent) of power costs and thus costs of being wrong on transmission investments is small relative to costs of uneconomic generation investments.

2. Non-Wires Alternatives

Transmission is one type of input to the electrical system. Other inputs to the system include different types of generators, distribution facilities, and end-use products. New investments in certain types of inputs can function as a complement or substitute for new transmission. For example, development of new coal generation or wind generation located far from loads will require new transmission to deliver electricity to load centers. In contrast, the continued reliance of gas-fired generation located near loads would reduce the need for significant new transmission facilities. Similarly, investments in demand-side management and distributed generation provide alternatives to increase performance of the electrical system without a corresponding increase in demand for new transmission.

Demand side management refers to measures designed to change the amount (energy efficiency) or timing (demand response) of electricity consumption. Energy efficiency investments enable the consumer to utilize less electricity to attain the same level of services from such tasks as lighting the home or office, operating appliances, and running electrical equipment. Demand response investments decrease consumption of electricity during peak hours and shift consumption to off-peak periods to increase the use of baseload generation. Energy management control systems can be used to switch electrical equipment on or off to reduce peak loads. Some energy management control systems allow off-site control by local utilities to alter timing of air conditioning, heating and lighting loads to reduce peak loads. Leveling load and reducing peak demand levels reduces a utility's need to use higher cost peak generation resources and invest in new peak generation. Many demand side management investments provide rates of returns that are competitive with supply side investments. The CDEAC Energy Efficiency Task Force report provides more detail on potential energy savings and economic benefits of demand management systems in WGA states. Reducing future demand provides an alternative to building new power plants and their associated transmission lines.

Distributed generation denotes small, modular electricity generators sited close to customer loads that are interconnected to the existing grid. Generator technologies for distributed generation systems include small scale wind, photovoltaic solar, biomass, gas microturbines, and heat and power systems. The Department of Energy's Distributed Energy Resource program has the long-term goal that distributed generation will achieve a 20% share of new electrical capacity additions by 2010. Strategically placed distributed resources can be used to defer or eliminate the need for new transmission and distribution line upgrades that would be needed for large centralized generation resources.

3. Technological Innovation for Transmission

Emerging technologies in the electrical system will increase the transfer capability of existing lines, enable more power to be delivered in existing rights-of-way, provide greater flexibility to site lines underground and in water, and improve overall power operations. Specific technologies that may lead to changes in transmission systems over the next twenty five years are described below.[4]

- High-Temperature Superconducting (HTS) cables have advantages of low resistance and capability to carry more current than standard wires of the same size. HTS cables would allow more power to flow on existing rights-of-way. The refrigeration system to reach superconductivity conditions, however, carries higher fixed and variable costs than conventional cable technology.

- Underground cables provide a transmission alternative in areas where overhead lines are physically impractical or publicly undesirable. Electric characteristics of underground cables limit AC lines to about 25 miles. Underground lines cost five to ten times the cost of overhead lines.

- Advanced transmission conductors with composite cores are lighter and have greater carrying capacity than current steel core conductors. These advanced composite conductors enable more power to flow across existing rights-of-way. A new core consisting of composite fiber materials has the potential of being stronger than steel core aluminum conductors, weigh 50% less, and reduce line sage by 250%.

- Compact transmission line configurations based on computer-optimized transmission line tower designs enable more power to flow over existing rights-of-ways.

- Increased phase transmission line configurations from three phases to six or twelve phases for AC high voltage power transmission enables greater power transfer in a given right-of-way. Expanded phase lines reduce electromagnetic fields from lines due to greater phase cancellation.

- Ultra high voltage lines would enable more power to be transmitted over paths that are currently carried over conventional transmission lines such as 230 kV, 345 kV and 500 kV. The highest transmission voltage line in North America is 765 kV. Ultra high voltage lines are technologically possible but would require larger rights-of-way, more reserves for reactive power, and generate stronger electromagnetic fields.

- High-Voltage Direct Current (HVDC) provides an economic alternative to long-distance AC transmission lines. HVDC lines can be used to link asynchronous systems, and applied to long distance transmission under ground and water. Disadvantages of DC lines are the additional costs of converting from AC to DC and then back to AC across the system and potential impacts on reliability

[4] Rocky Mountain Area Transmission Study, 2004, Appendix C.3.b; J. Hauer, T. Overbye, J. Dagle, and S. Widergren, Advanced Transmission Technologies, Issue Papers, 2002.

calculations in underlying AC transmission systems. To date, there are several thousand miles of HVDC transmission lines in North America.

- Flexible AC Transmission Systems (FACTS) devices use power electronics to improve power system control and thereby increase power transfer levels without new transmission lines. Current high cost of FACTS devices makes the application uneconomic for most transmission operators.

- Energy storage devices enable greater flexibility to utilize low cost energy generated during off-peak hours to meet consumption during peak hours and improve power system operations. Energy storage technologies for electrical systems include pumped hydro storage, compressed air energy, superconducting magnetic energy storage (SMES), flywheels, and batteries.

II. ENCOURAGING EFFICIENT USE AND EXPANSION OF WESTERN TRANSMISSION INFRASTRUCTURE: POLICY RECOMMENDATIONS

A. BACKGROUND

Development of clean and diversified generation resources for the West depends upon utilizing the existing transmission system more efficiently and expanding the transmission system. The existing transmission system is not the product of a master plan. It evolved as vertically integrated utilities historically constructed transmission to connect their new generation to loads, to share reserves and improve reliability, and to take advantage of generation and load diversity. In the past, utilities justified the economics of options to meet demand by examining the combined cost of the power plant and related transmission. Regulatory changes restructured electric utilities, functionally separating generation and transmission. Today, transmission system investment must be justified on its own. To ensure adequate transmission infrastructure is in place when it is needed, it is essential to anticipate the amount and location of future load growth and generation additions.

In the 1970s and 1980s the Western transmission system grew significantly to accommodate long distances between new coal generation and load centers. Individual companies invested to expand the grid to meet their increasing demand. In the mid-1990s, the federal government launched the era of open transmission access to enable a more competitive wholesale electric power market. The transmission system was now called upon to enable a competitive market. In the late 1990s and early 2000s, nearly all new generation in the West was fueled with natural gas. These plants were typically built near load centers, thus little new transmission was needed. With recent higher natural gas prices, the focus has shifted to other generating resources, many of which are located far from load centers and will require significant new transmission investment.

Over the past five years, numerous studies have examined transmission adequacy, potential obstacles to efficient use of the existing transmission system and construction of new transmission, and scenarios for future transmission expansion. See Table 1 below. Some entities developed policy recommendations to overcome barriers to transmission.[5]

[5] National Association of Regulatory Utility Commissioners (NARUC), NARUC'S National Electricity Policy, (http://www.naruc.org/displaycommon.cfm?an=1&subarticlenbr=29); American Public Power Association / Transmission Access Policy Study Group, APPA/TAPS Position Paper: Effective Incentives to Getting New Transmission Built, (http://www.tapsgroup.org/sitebuildercontent/sitebuilderfiles/030918finalincentives.pdf); Edison Electric Institute, EEI Principles on Transmission Investment, March 17, 2005 (EEI Principles) (http://www.eei.org/industry_issues/energy_infrastructure/transmission/eei_tranmission_principles_5_10.pdf?ObjectID=35619).

Table 1
TRANSMISSION STUDIES 2001-2005

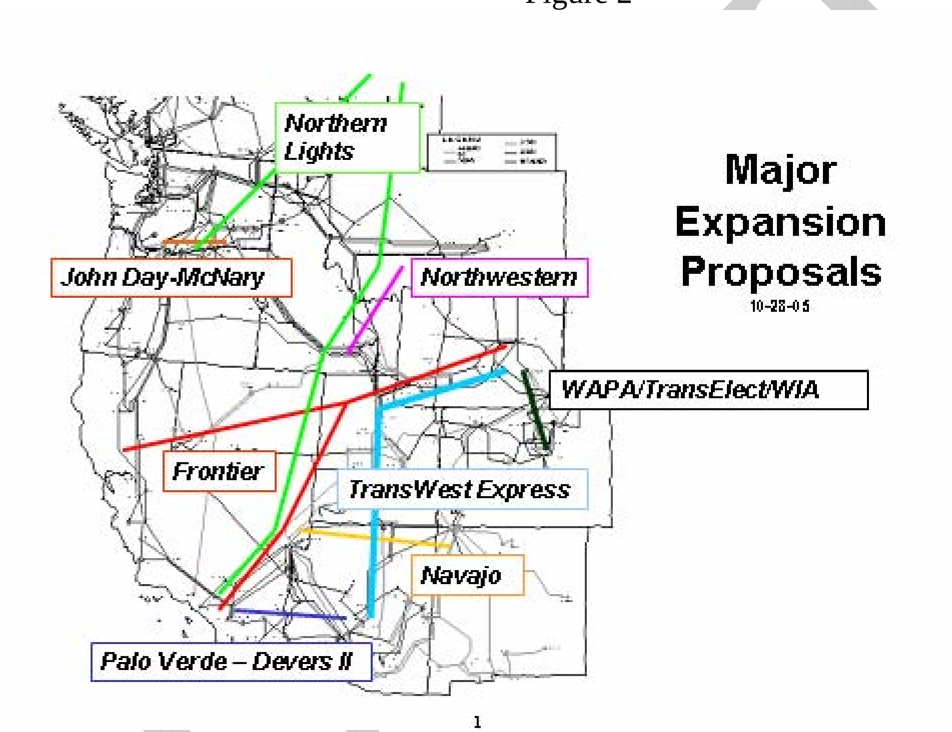
Western Governors' Association, *Conceptual Transmission Plans for Electricity Transmission in the West*, August 2001 (WGA 2001) (http://www.westgov.org/wga/initiatives/energy/transmission_rpt.pdf);
Federal Energy Regulatory Commission, *Electric Transmission Constraint Study*, 2001;
Western Governors' Association, *Financing Electricity Transmission Expansion in the West: A Report to the Western Governors*, February 2002 (WGA 2002) (http://www.westgov.org/wga/initiatives/energy/final_rpt.pdf);
U.S. Department of Energy, *National Transmission Grid Study*, May 2002, (http://www.eh.doe.gov/ntgs/gridstudy/main_print.pdf);
Seams Steering Group-Western Interconnection, *Western Interconnection Path Flow Study*, February 2003 (Path Flow Study) (http://www.ssgwi.com/documents/320-2002_Report___final_pdf.pdf);
Seams Steering Group-Western Interconnection, *Framework for Expansion of the Western Interconnection System*, October 2003 (SSG-WI 2003) (http://www.ssg-wi.com/documents/316-FERC_Filing___103103___FINAL_TransmissionReport.pdf);
Midwest ISO, *Transmission Expansion Plan 2003 (MTEP-03)*, June 19, 2003, (http://www.midwestiso.org/plan_inter/documents/expansion_planning/MTEP%202002-2007%20Board%20Approved%20061903.pdf).
Rocky Mountain Area Transmission Study, September 2004 (RMATS) (http://psc.state.wy.us/htdocs/subregional/Reports.htm);
Federal Energy Regulatory Commission, *Assessing the State of Wind Energy in Wholesale Electricity Markets: Staff Briefing Paper*, Docket No. AD04-13-000, November 2004 (FERC Wind Paper);
Midwest ISO, *Transmission Expansion Plan 2005* (METP 05), June 2005 (http://www.midwestiso.org/plan_inter/documents/expansion_planning/MTEP05_Report_061605.pdf);
Southwest Power Pool, *SPP RTO Expansion Plan 2005-2010*, Sept. 2005, (http://www.spp.org/Publications/Final_Exp_Plan_TWG_Approved_092605.pdf);
Electric Reliability Council Of Texas, *Transmission Issues Associated With Renewable Energy in Texas: Informal White Paper for the Texas Legislature*, 2005; March 28, 2005. (http://www.ercot.com/AboutERCOT/TexasRenewableWhitePaper2005/RenewablesTransmissionWhitePaperFINAL.pdf);
The Keystone Center, *Regional Transmission Projects: Finding Solutions*, June 2005 (Keystone) (http://www.keystone.org/FINALREPORT6_2005Regional_Transmission_Projects.pdf);
Edison Electric Institute, *Meeting U.S. Transmission Needs*, July 2005;

The Rocky Mountain Area Transmission Study was launched by the Governors of Wyoming and Utah in 2003 after they found:

> "For many years, utilities and other entities have been reluctant to make investments in needed electric transmission infrastructure. This has been due to a number of factors, including protracted uncertainties in the regulatory environment and nascent regional transmission organizations under development. As a consequence of this lack of transmission expansion, transmission congestion and bottlenecks are increasing. While this is a problem throughout the western interconnect, it is becoming an acute issue in areas of the Rocky Mountain sub region."

With the emergence of many active sub-regional planning processes in this decade, important progress has been made in evaluating opportunities for increased system utilization and enhancement. This is particularly the case in the southwest sub-areas of the west, where STEP and SWAT have been active. As a result of the subregional and utility planning processes, important new multi-state projects have been announced, including TOT 3 upgrade, TransWest Express, Frontier Line, Palo Verde-Devers II, and others. Independent transmission companies are also key players in new project development, including Transcanada (NorthernLights) project, National Grid and others. See Figure 2 below. Prospects are good for selected projects moving forward to permitting in 2006-7.

Figure 2



Continued access, utilization and enhancement of the western system will require a concerted effort of state, regional and federal entities. WECC and FERC are increasing their focus on transmission development issues. In April 2005, for example, FERC held a technical conference to explore potential impediments to transmission investment.[6] EPAct has directed DOE to undertake a study in transmission congestion and provide a report to Congress in August, 2006. WECC is proposing a significant budget increase in 2006 to begin undertaking expansion planning and modeling studies.

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[6] Technical Conference, Federal Energy Regulatory Commission, April 22, 2005, Washington, D.C. Docket Nos. AD05-05-000 and PL03-1-000.

This increased regional and federal activity can be supported by and will necessitate parallel increase in state attention on congestion, access, increased utilization and expansion planning/permitting. In the following sub-sections, policy options for improved state/regional federal activities are explored for two broad areas where continuing policy challenges exist:

- EFFICIENT USE OF EXISTING TRANSMISSION SYSTEM
  - Review of Historical Flows
  - Conditional Firm and Related Tariff Reform
  - Evaluation of ATC
  - Rate Pancaking
  - Control Area Consolidation
  - Economic Dispatch of Transmission
  - Common Oasis
- TRANSMISSION EXPANSION
  - Planning
  - Cost Allocation and Cost Recovery
  - Siting and Permitting

Specific issues reviewed with an eye to enhancing the use of the existing transmission system and enabling expansion of the grid include:

1. The lack of long-term firm available transfer capacity (ATC) over many key transmission paths despite operational data showing that many of these paths are congested for a small percentage of time over a year.[7]

2. Restrictive transmission service options under Order No. 888 *pro forma* tariff rules (long-term firm point-to-point and non-firm point-to-point transmission service) that inhibit greater utilization of the existing transmission grid outside of regions covered by Regional Transmission Organizations (RTOs) or Independent System Operators (ISOs).[8]

3. Rate pancaking practices require transmission customers to pay access fees to each transmission operator across paths linking points of generation to points of use.[9]

4. Fragmented transmission planning conducted on a project-specific basis that did not consider transmission expansion across the entire region or subregion prior to 2001, and lacked transparency in data and modeling efforts.[10]

[7] FERC Wind Paper, p. 20; SSG-WI Path Flow Study
[8] FERC Wind Paper, p. 20-23; RMATS, p. 5-14 – 5-16
[9] FERC Wind Paper, p. 24
[10] WGA 2001, p.11; National Wind Coordinating Committee, Wind Energy Interconnection Issue Brief, September 2003 (NWCC Interconnection 2003) (http://www.nationalwind.org/publications/transmission/transbriefs/Interconnection.pdf).

5. Clogged queues for generator interconnection under current rules of open access transmission service.[11]

6. Jurisdictional split in regulatory authority by federal, state, and local governments over all facets of electric transmission.[12]

7. Developer uncertainty about regulatory decisions regarding cost allocation and cost recovery, including concern about differences among state PUCs on interstate transmission projects and risks of not recovering costs, or not recovering costs in a timely way between state and federal regulators.[13]

8. Transmission investments entail large lumpy capital expenditures and long lead times requiring project developers to bear significant upfront costs prior to use of the project and a prudent investment determination.[14]

9. Uncertainty about effective ownership or use of transmission rights under FERC's open access transmission policy, interconnection requests by other generators, and loop flow problems.[15]

10. Uncertainty about the institutional structure of the electricity market and whether RTOs would form to perform key functions in specific regional markets.[16]

11. Difficulties in permitting and siting new transmission lines. Project sponsor concern about gaining approval in multiple governmental forums for interstate lines including states and county governments. Concern about justifying new transmission in the face of arguments that the existing transmission system is not being fully utilized.[17]

12. Concern about siting of transmission on federal lands in the West. This includes the challenge of securing timely regulatory approvals from multiple land management agencies (BLM, Forest Service, and Department of Defense) and facing extensive NEPA requirements over large land areas.[18]

[11] NWCC Interconnection 2003; FERC Technical Conference on the Queue for Interconnection Requests, Docket Nos. RM01-12-000, RM02-1-000, RM02-12-000, January 21, 2003 .
[12] Keystone, p. 2;
[13] WGA 2002, p.3, 14; RMATS, p. 4-1-3; EEI Principles; Eric Hirst, Expanding U.S. Transmission Capacity, August 2000, p. 14-16.
[14] RMATS, p. 4-1-4-3; EEI Principles; Hirst, p. 14-16.
[15] WGA 2002, p.14; RMATS, p. 4-2;
[16] WGA 2001, p. 1; WGA 2002, p.3; RMATS, p.4-1-4-3.
[17] WGA 2001, p.12-13; DOE 2001, p. 53-57; Keystone, p. 26-30.
[18] RMATS, p. 5-2; DOE 2001, p. 57-58.

B. CHALLENGES AND POLICY OPTIONS

The Transmission Task Force identified policy recommendations motivated by the principles of technological efficiency and economic efficiency. Technological efficiency refers to maximizing physical output for a given level of inputs. Economic efficiency defines the allocation of resources that maximizes net benefits for society, or the maximization of total benefits less total costs.[19]

1. Efficient Use of the Existing Transmission System

Background

FERC's Open Access Transmission Policies

Order 888. In 1996, the Federal Energy Regulatory Commission (FERC) issued Order No. 888 with the dual purpose of remedying undue discrimination in access to monopoly owned transmission system and promoting competition in wholesale electricity markets.[20] In combination with Order No. 889,[21] FERC required all transmission owners and operators to (1) file open access non-discriminatory transmission tariffs that contain terms and conditions of non-discriminatory service, (2) execute their own wholesale sales and purchases of electricity under the open access tariffs, (3) functionally separate transmission from generation marketing functions and communications, and (4) develop an open access same-time information system (OASIS) that provides all transmission market participants access to specified information about transmission services.

FERC's Order 888 *pro forma* Open Access Transmission Tariff (OATT) required transmission providers to file a single open access tariff that offers network and point-to-point transmission service. In the Western Interconnection, the most relevant type of transmission service is the point-to-point service.[22] The pro forma tariff specifies two types of point-to-point transmission service: firm and non-firm service. Firm service provides a nearly unconditional amount of transmission service to transmission customers for specified terms. Non-firm transmission service is reserved and scheduled on an as-available basis and can be curtailed and interrupted under certain conditions. Non-firm transmission service cannot be contracted for longer than one year.

[19] This definition of economic efficiency assumes that we can measure benefits and costs from output prices and input prices, respectively, inclusive of all externalities, and there is a fair initial distribution of income. The more general Pareto criterion defines economic efficiency as an allocation of resources where it is not possible to make one person better off without making another person worse off.
[20] Order 888, Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, 75 FERC 61,080 (April 24, 1996).
[21] Order 889, Open Access Same-Time Information System (formerly Real-Time Information Networks) and Standards of Conduct , 75 FERC 61,078 (April 24, 1996)
[22] Point-to-Point transmission service is defined as "the receipt of capacity and energy at designated Point(s) of Receipt and the transmission of such capacity and energy to designated Point(s) of Delivery." Order 888, Appendix D, p. 35.

Specific terms and conditions of point-to-point transmission service are set forth in the pro forma tariff in Appendix D of Order 888. Section 13.2 of the pro forma tariff specifies the reservation priority method for the types of point-to-point transmission service as follows:

- Long-term firm point-to-point transmission service shall be available on a first-come, first-served basis, i.e. in the chronological sequence in which each transmission customer has reserved service.

- Firm point-to-point transmission service will always have a reservation priority over non-firm point-to-point transmission service.

- The priority of short-term firm point-to-point transmission service will be conditional based upon the length of requested transaction. If the transmission system becomes oversubscribed, requests for longer term service may preempt requests for shorter term service up to specified deadlines in accordance with the term of service.

Under these rules, long-term firm point-to-point transmission service became the desired and only realistic tariff option for developers of new generator projects. Prospective developers have explained that in order to obtain financing for their projects, the lending community requires guarantees that generators will have access to transmission and be able to sell electrical output reliably over 20-year project terms. Non-firm transmission tariffs do not provide sufficient guarantees for renewal over time to justify the initial investment. As a result, long-term firm transmission service has been the only viable option for most new generation projects.

Under the *pro forma* tariff rules of Order 888, long-term firm point-to-point transmission service is allocated on a sequential first-come, first-served basis. Transmission providers have implemented this policy by creating a queue for transmission service. Transmission customers can make requests for transmission service. If there is insufficient transmission capacity, transmission service will be rationed according to the transmission service queue or the transmission customer will be given an opportunity to pay for the construction of new transmission.

Order 888 did not address the longer term problem of deciding how to process competing generator requests to interconnect with the grid. Issues related to generator interconnection procedures have become formalized in national standards in recent years with FERC issuance of new interconnection rules governing large and small generators.

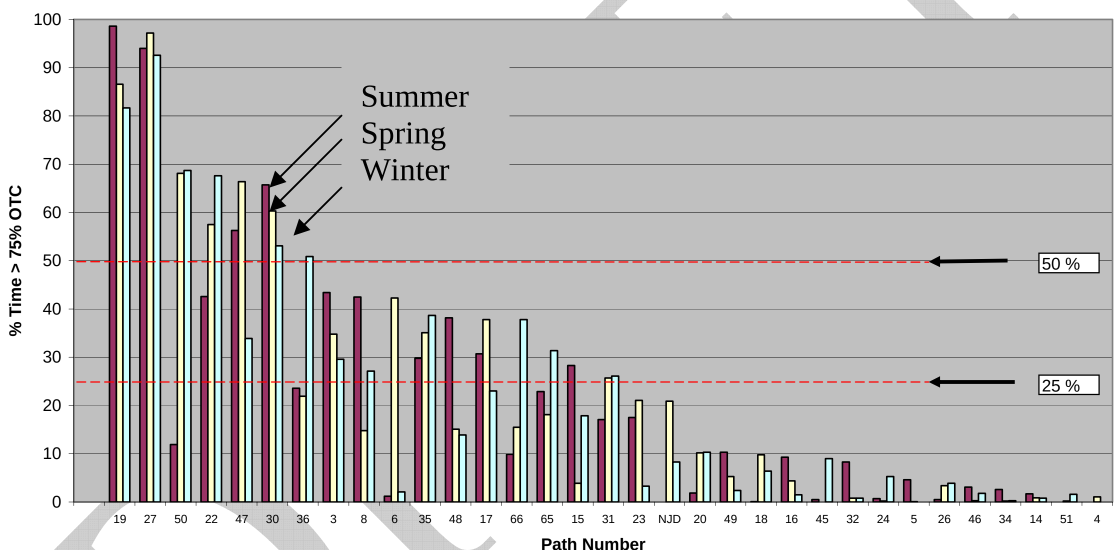
Emerging Issues Under Order 888

Historical Flows. Analyses of historic flows on major transmission paths in the Western Interconnection suggest the existing transmission system could be utilized more efficiently and provide transmission capacity for new clean and diversified resources.

The Seams Steering Group-Western Interconnection (SSG-WI) conducted an analysis of actual flows in the Western Interconnection for 1998-2002 using data from the Western Electricity Coordinating Council's Extra High Voltage data base. The graph below shows summary data from SSG-WI's 2003 report on actual flows. It shows the percentage of time major transmission paths reached at least 75 percent of the Operating Transfer Capacity (OTC) limit during the highest summer, spring, and winter season from 1998-2002. The data suggests many paths operate significantly below their physical capacity throughout most of the year.

Figure 3

Path Loading - % of Time > 75% of Path OTC during a Seasonal Period
Maximum Seasonal Loadings for each Path
Winter 98-99 thru Spring 2002



Source: *Western Interconnection Transmission Path Flow Study*, SSG-WI, February 2003

Tapping potential excess capacity on the existing transmission system is problematic under existing rules for transmission tariffs. For point to point service, a generator can obtain firm service for a period of more than one year provided there is sufficient available transfer capability (ATC). Alternatively, non-firm service can be obtained for time periods up to one year. When generators request firm transmission service, transmission operators must assess whether the requested path capacity is available for the entire period of the request. If a path is projected to be constrained for even a few hours during the period, firm service will not be offered, and generators must resort to obtaining non-firm service.

A number of new proposals described below could lead to a more efficient use of the existing transmission system.

Conditional Firm and Related Tariff Reform. The Federal Energy Regulatory Commission (FERC) held a workshop in Portland in March 2005 to explore possible conditional firm transmission products under consideration by the Bonneville Power Administration (BPA).[23] BPA's proposed conditional firm (CF) and commercial redispatch products would be offered only in cases where long-term capacity is not available to serve a transmission request during some months of the year. The proposed CF product would be a long-term transmission service that provides for as many months of firm service as possible during the year, combined with a specified number of hours over a set number of "conditional" months when firm transmission service may not be provided. This new form of service could allow transmission providers to offer more service and potentially serve new resources that would otherwise not be able to get on line.

A Commercial Redispatch product is called for in FERC's *pro forma* OATT, however, utilities have not yet offered it. This product would allow a transmission owner to offer more long term service when their system is constrained on one or more paths by arranging for dispatch of generation resources to relieve those constraints when the system is at peak usage.

The Western Area Power Administration (Western) offers a Priority Non-Firm product on a long term basis, which has a curtailment priority below "firm" service but higher than all other "non-firm" service. This may have limited potential to enable new projects to get financing, but may provide for more use of the existing grid.

ATC Evaluation. The North American Electric Reliability Council (NERC) released a final report by its Long-Term AFC/ATC Task Force that examined issues and made recommendations on coordination, calculation and consistency of ATC calculations.[24] FERC responded with a Notice of Inquiry about NERC's ATC report and information needed to promote greater transparency in electricity markets and reduce reporting burdens on industry.[25]

In the West, BPA recently reviewed its ATC methodology and estimates on numerous key transmission corridors. Based on this reevaluation, BPA revised ATC levels upward by more than two thousand aggregate MWs.[26] Other transmission providers could be encouraged to review their ATC calculations on lines as a means of improving utilization of the existing infrastructure. Over the past year, WestConnect

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[23] Federal Energy Regulatory Commission, Technical Workshop on Additional Wholesale Electric Transmission Services Under Order No. 888 Open Access Pro Forma Tariff, Docket Nos. RM05-7-000 and AD04-13-000, Portland, OR, March 16-17, 2005.
[24] Long-Term AFC/ATC Task Force Final Report, NERC, April 14, 2005 (www.nerc.com/pub/sys/all_updl/docs/pubs/LTATF_Final_Report_Revised.pdf)
[25] Federal Energy Regulatory Commission, Notice of Inquiry, Information Requirements for ATC, Docket # RM05-17-000, May 27, 2005.
[26] On June 22, 2005, BPA posted revised upward ATC calculations for the following lines by the following amounts: West of McNary (330 MW), West of Slatt (501 MW), North of Hanford (489 MW), North of Jday 776 MW), Allston-Keeler (304 MW), Monroe-Echolale (37 MW), Paul-Allston (106), and Raver-Paul (111 MW).

transmission providers[27] collaborated and developed common ATC definitions and methodology.[28] This effort helps ensure common standards and terminology for transmission services across this sub-regional area.

Rate Pancaking. Transmission customers outside of RTO/ISO systems can incur charges or access fees for contracting electric transmission on a path between the generator and the delivery point on the grid. The practice of imposing separate fees by multiple transmission owners is known as "rate pancaking." Charges by transmission owners can range between $3/MWh to $5/MWh even though the marginal cost of such transmission is less than these fees.[29] These charges can easily double the cost of power purchases involving long distance transmission.[30] Utilities can eliminate these multiple charges for transmission by forming RTO/ISO systems or collaborating on regional transmission pricing. One alternative to rate pancaking is for a regional transmission system to establish "postage stamp" rates which are a single, uniform, average rate across all utilities in the system. A second alternative is the "license plate" approach where by rates for service increase across zones in the transmission system. The license plate concept allows utilities to maintain its existing rate for transmission service within its zone and reduces cost shifting.[31]

Eliminating rate pancaking can produce significant savings for transmission customers. The California Independent System Operator (CAISO) is in a transition period with individual rates for the ten transmission owners to reach a single rate for the entire CAISO by 2010. The estimated annual transmission cost savings to some load serving entities in CAISO will be as high as $23.9 million per year. MISO eliminated rate pancaking by adopting a single regional tariff. As a result, the cost of transmitting 100 MWh of electricity from a coal plant in Indiana through three transmission systems to Detroit dropped from $1,718 to $464, for a savings of $1,254 in transmission costs for a single transaction.[32]

Control Area Consolidation. "Control areas," or "balancing authorities" as they are now called, are the entities responsible for performing power system operations over a given area in the grid. Control area operators make daily and hourly decisions about dispatching generators to ensure there is power to meet load, arrange for reserve generation, and coordinate with other control areas to ensure reliability of the entire system. In the Western Interconnection, there are 34 different control areas. MISO has

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[27] WestConnect parties include Arizona Public Service, El Paso Electric Company, Imperial Irrigation District, Public Service Company of Colorado, Public Service Company of New Mexico, Salt River Project, Southwest Transmission Cooperative, Tri-State Generation and Transmission Association, Tucson Electric Power Company, and Western Area Power Administration.

[28] WestConnect Transfer Capability Stakeholder Meetings, Phoenix, AZ, February 1, 2005 and Denver, CO, June 22, 2005.

[29] Statement of William L. Massey on Behalf of the American Wind Energy Association, Comments of the American Wind Energy Association, Docket No. RM05-25-000, Nov. 22, 2005, p.13.

[30] Comments of the American Wind Energy Association, Docket No. RM05-25-000, Nov. 22, 2005, p.10 (AWEA Comments 2005).

[31] FERC Wind Paper, p. 24.

[32] ISO/RTO Council, The Value of Independent Regional Grid Operators, November 2005, p. 21-22.

37 control areas. Control areas vary in size and typically have different portfolios of generation resources. Control areas that operate over larger areas with more generating resources can derive economies of scale. Generation resources and dispatchable load provide a control area with operating reserves. Control area operators utilize operating reserves to respond to unexpected contingencies and to track changes in demand. Control areas that operate over a large region have the benefit of sharing greater resources that enables the control area to use the most cost-effective units available to meet demand and standby needs. Large control areas also have a greater system capability to integrate greater amounts of intermittent resources such as wind and solar energy than smaller control areas.[33] Additionally, some observers point to small control areas as a factor that reduces system reliability because the grid becomes more fragmented and decentralized resulting in greater seams, and greater coordination and communication issues between adjacent system operators.[34]

Economic Dispatch of Transmission. Under current operating procedures in much of the WGA region, use of the existing transmission system during congested periods may not be economically efficient since higher value power transactions can be denied transmission access in favor of lower value power sales.[35]

In the Western Interconnection, parties are prohibited from scheduling power transfers on the transmission system if such schedules would exceed pre-calculated OTC capacity limits of the transmission path. The Western Interconnection has also adopted a loop flow mitigation procedure to help compensate for the fact that contract path transmission scheduling does not reflect the electric reality that power in an AC network will flow over the path of least resistance, which may not be the contract path. However, this loop flow mitigation procedure does not account for the economic value of different power sales when curtailing use of the transmission system.[36]

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[33] AWEA Comments 2005, p. 9-10.

[34] For reliability issues associated with small control areas, see United States-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations, April 2004, (http://www.electricity.doe.gov/resources/reports.cfm?section=resources&level2=reports) "Some observers believe that some U.S. regions have too many control areas performing one or more of the four critical reliability functions. In many cases, these entities exist to retain commercial advantages associated with some of these functions. The resulting institutional fragmentation and decentralization of control leads to a higher number of operating contacts and seams, complex coordination requirements, misalignments of control areas with other electrical boundaries and/or operating hierarchies, inconsistent practices and tools, and increased compliance monitoring requirements. These consequences hamper the efficiency and reliability of grid operations. . . . Moreover, it is not clear that small control areas are financially able to provide the facilities and services needed to perform control area functions at the level needed to maintain reliability." p. 146.

[35] That is, high value power sales (that would lower overall variably electricity production costs) would be bumped off the system during times of transmission congestion in favor of lower value power sales that happen to own rights to use the transmission system at the time of congestion.

[36] In the Eastern Interconnection, schedules are generally allowed up to the thermal limit of the line. When reductions are required because moving all the scheduled power over a line would threaten reliability, a Transmission Loading Relief (TLR) order is issued and schedules are curtailed on a pro rata basis without regard to which transactions are of greater value.

Regional Transmission Organizations (RTOs) offer the opportunity to create a transmission congestion management system that allows access to least-cost generation within reliability security constraints. A least-cost congestion management system would generate a price on congestion in transmission, and thereby create a price signal mechanism to inform decisions involving construction of new transmission capacity, location of new central power plants, and use of distributed generation and load management programs in mitigating transmission congestion. However, RTOs have been difficult to form and often result in significant additional costs. As a result, FERC has refocused its attention toward revisions to Order 888,[37] as opposed to pressing for formation of RTOs.

Under most RTO congestion management systems, an RTO would distribute a transaction between two points on the transmission grid across "flow paths," or links in a simplified model of the RTO's transmission system. For the transaction to be accepted, the transmitting party would either demonstrate it held firm transmission rights (FTRs) between the point of injection and the point of withdrawal, or it would have to specify its willingness to pay congestion costs. The RTO would manage congestion by purchasing reverse transactions or an appropriate mixture of increments and decrements of generation and loads or both at various points around the grid. The value of FTRs would reflect the marginal congestion management costs between the specific pairs of nodes that they represent.

In this type of transmission congestion management system, higher value economic power sales would use the transmission system before lower value power sales. In the WGA states, there are four operating RTO-like organizations, the Midwest Independent System Operator (MISO), the California Independent System Operator (CAISO), the Southwest Power Pool (SPP), and the Electric Reliability Council of Texas (ERCOT). RTOs have been proposed in the Northwest (GridWest) and the Southwest (WestConnect) but they are years from implementing economic-based transmission congestion systems. In addition to reaching agreement on a transmission congestion management system, GridWest and WestConnect must resolve many other hurdles before becoming operational.

Section 1234 of the new federal Energy Policy Act of 2005 requires the Department of Energy (DOE) to produce studies on economic dispatch 90 days after enactment and yearly thereafter.[38] The study must examine procedures currently used by utilities to perform economic dispatch, identify opportunities to include nonutility generation resources for economic dispatch, and consider potential benefits of implementing expanded economic dispatch. Under Section 1298, FERC shall convene regional joint boards to study security constrained dispatch in various market regions and submit a report to Congress on recommendations by joint boards.

[37] Federal Energy Regulatory Commission, Notice of Inquiry, Preventing Undue Discrimination and Preference in Transmission Service, Docket # RM05-25-000, September 16, 2005.

[38] Energy Policy Act of 2005, Section 1234, Study on the Benefits of Economic Dispatch. EPAct defines "economic dispatch" as "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities."

Common Oasis. In the absence of widespread RTOs, formation of a common OASIS site such as WesTTrans helps improve efficiency of the existing transmission system. The WesTTrans OASIS site creates a single electronic location that facilitates transactions among customers and 23 transmission providers by the end of 2005.[39] Parties interested in transmission services can conduct multi-provider queries among participating transmission providers, post information to other transmission customers on a common bulletin board, facilitate execution of deals with multiple transmission providers, and post requests to buy or sell reserved capacity in a secondary market for transmission rights.

Recommendations: Efficient Use of the Existing Transmission System

Western Governors should urge FERC, NERC and WECC to act in the near-term to promote the efficient use of the transmission system that supports the dispatch of least-cost generation within reliability constraints. FERC has started a formal review of potential reforms to Order 888, OATT,[40] and ATC[41] which may provide the venue for implementing many of these recommendations.

> ***Recommendation 1: Conditional Firm.*** Governors and state regulators should encourage FERC to reform transmission tariff policy to make available conditional-firm, redispatch, and related tariff products. The development of a conditional firm product would improve the utilization of available capacity in the transmission system that would otherwise not be utilized. The conditional firm product would enable generators more flexibility to obtain transmission services on paths that are not available under firm transmission to use these paths a part of the year and more efficiently utilize the existing transmission system.[42]

> ***Recommendation 2: Reevaluate ATC.*** Governors, state regulators and FERC should adopt policies to encourage transmission providers to pursue transparent reviews and reasonable assessments ATC levels on their existing transmission paths. The review would also evaluate the adoption of a flow based ATC measure. Additional non-wires alternatives would potentially include (a) release or re-use of unused ATC, and (b) development and use of real-time line ratings. The latter would improve the odds of uncovering additional ATC because static line ratings are used on many paths. There is a need to study and identify, in a comprehensive way, grid locations that are favorable for near-term generation additions that require no or minimal grid upgrades.[43]

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[39] See http://www.westtrans.net/.
[40] Federal Energy Regulatory Commission, Notice of Inquiry, Preventing Undue Discrimination and Preference in Transmission Service, Docket # RM05-25-000, September 16, 2005.
[41] Federal Energy Regulatory Commission, Notice of Inquiry, Information Requirements for ATC, Docket RM05-17-000, May 27, 2005.
[42] CDEAC Wind Task Force Draft Report, Sept. 6, 2005 ("Wind Task Force"), p. 51.
[43] Wind Task Force, p. 51.

Recommendation 3: Rate Pancaking. Mechanisms should be developed to minimize or eliminate rate pancaking to facilitate intercontrol area transactions. New transmission service products should be developed that enable recovery of revenue requirements across as broad an area as possible. Such products should respect existing jurisdictional authority and promote utilization of the grid across temporal and geographic boundaries.

Recommendation 4: Control Area Consolidation. Control area consolidation should be widely adopted. In the absence of actual physical control area consolidation, techniques that provide some of the benefits of control area consolidation should be more widely adopted within and across subregions. This may include dynamic scheduling and metering of reserves and regulation resources, software enhancements to facilitate reserve sharing, and other technological advances that promote broad and efficient markets for clean and diversified resources.

Recommendation 5: Economic Dispatch of Transmission**.** Governors, state regulators and FERC should encourage formation of congestion management systems that allow access to least-cost generation within reliability and security constraints. A congestion management system would set transmission prices to reflect the cost of congestion on the system, and improve market signals for transmission expansion, generator location, and distributed generation resources.[44] This effort should explore potential applications in non-RTO systems and collaborate with future Department of Energy studies on economic dispatch as prescribed by Section 1234 of the Energy Policy Act of 2005. Governors should ensure that states participate actively in FERC organized joint boards that will study and make recommendations on constrained dispatch in regional markets.

Recommendation 6: Common OASIS**.** Governors and state regulators should encourage the formation of a common OASIS site to facilitate market transmission transactions in a regional geographic area. Common OASIS sites reduce administrative costs of communication, inquiries, and collaborating among potential customers and multiple transmission providers.

[44] Wind Task Force, p. 57.

2. Transmission Expansion

Even with more efficient use of the existing transmission system, achieving the goal of 30,000 MW of clean and diversified electricity generation will require expansion of the transmission system. A successful strategy to implement transmission expansion to reach clean and diversified generation requires a three prong effort to address issues (a) transmission planning; (b) cost allocation and cost recovery of new transmission investment; and (c) siting and permitting of transmission facilities.

a. Transmission Planning

Background

The existing transmission system is the product of historical discrete decisions by utilities. Individual utilities, and occasionally groups of utilities, built transmission on a project specific basis to link distant generating resources to loads or to interconnect with their neighbors to share reserves and exchange economy energy. There was no regional transmission plan. This system worked reasonably well prior to FERC orders to provide open transmission access and development of regional power markets.

Western Transmission Planning Efforts

During the Western electricity crisis of 2000-2001, Western Governors asked a roundtable of utilities, independent power producers and regulators what new transmission was needed. While past transmission planning efforts examined specific proposed projects, such plans were not of sufficient scope to answer the Governors' questions. As a result, Western Governors directed a short-term effort to develop a conceptual transmission plan for the Western Interconnection. A joint industry and state effort produced a transmission report to Western Governors in August 2001.[45] The Governors asked that this type of pro-active, interconnection-wide planning be institutionalized.[46]

Numerous transmission planning efforts have emerged since the 2001 report to Western Governors. In the Western Interconnection, transmission planning at the regional level occurs through the Seams Steering Group-Western Interconnection (SSG-WI) effort. At the sub-regional level, five organizations formed to address planning and potential expansion projects: Southwest Area Transmission (SWAT); Southwest Transmission Expansion Plan (STEP); Rocky Mountain Area Transmission Study (RMATS); Northwest Transmission Area Committee (NTAC); and Colorado Coordinated Planning Group (CCPG). These ad hoc efforts rely on voluntary contributions of resources and lack sustained reliable funding mechanisms. The SSG-WI interconnection planning

[45] Conceptual Plans for Electricity Transmission in the West, Report to the Western Governors' Association, August 2001, (http://www.westgov.org/wga/initiatives/energy/transmission_rpt.pdf).
[46] WGA Resolution 05-02, Regional Electricity Policy Making, June 14, 2005, http://www.westgov.org/wga/policy/05/regional-electricity.pdf.

effort will likely terminate in 2006. Future interconnection-wide planning is expected to be performed by the Western Electricity Coordinating Council (WECC). In the Eastern Interconnection and Texas, MISO, SPP and ERCOT perform regional transmission planning as part of the institutional function of these RTO/ISO entities.

The western transmission planning efforts have generally adopted the following principles and characteristics in the planning process:

- *Pro-active* – Planning process must be pro-active in evaluating future areas of congestion and identifying the areas where new transmission is needed in the future, rather than forming an analysis around a specific target project.
- *Open* – Planning processes should be open to all parties and is driven by the interests of load serving entities, generation developers, state policy makers, and interest groups, as well as transmission owners.
- *Transparent* – Planning should rely on transparent data and modeling tools that are available and verifiable by all parties.
- *Comprehensive* – Planning should have capabilities to evaluate impacts of demand-side and supply-side resources in evaluating need for transmission and it should consider new transmission technologies.

Pro-active, open, transparent comprehensive transmission planning processes provide the framework to develop consensus and facilitate new transmission. The planning process can generate information on who benefits from transmission expansions. This is particularly important in areas without RTOs, since absent an RTO there is no mechanism to force unwilling parties who would benefit from a project to pay for part of the project.

Open, pro-active, stakeholder-driven transmission planning supported by Western Governors (Resolution 03-19) has taken hold in most of the WGA region. However, often such planning is done on an ad hoc, voluntary basis without sustained financing or an institutional structure. While producing useful analysis, such ad hoc processes are inadequate to contribute to the other steps necessary to build transmission, such as financing, permitting and construction. Such ad hoc processes also limit development of new analytic tools that would do a better job of evaluating costs and benefits of new transmission and identifying beneficiaries of transmission expansion.

The transmission planning process can improve overall efficiency if properly timed and coordinated with resource acquisition plans of load serving entities (LSEs) and plans of generators in the system. Synchronized planning schedules would enable (1) regional transmission plans to reflect resource acquisition plans of load serving entities and (2) LSE resource acquisition plans to incorporate options that are created by significant transmission expansion that may be beyond the scope of any single LSE.

The value of pro-active transmission planning in developing projects can be undercut by the present FERC-mandated queuing requirements for transmission interconnection and transmission service requests. The current queue policy requires that requests be processed sequentially on a first-come, first-served basis. Despite the laudable intent, this policy imposes a restrictive criterion on transmission interconnection requests that may result in economic transmission expansion opportunities being overlooked and lower cost resources being unavailable. Planning processes can identify large scale transmission investments that would lower costs and allow more distant clean and diversified resources to be available to meet needs of load serving entities.

FERC Generator Interconnection Policies

Order 2003 and the Generator Interconnection Queue. In July 2003, FERC issued Order 2003 that set forth standardized procedures and agreement terms for large generators seeking interconnection to the transmission grid.[47] Large generators were defined as having a capacity of more than 20 MW. FERC developed a related interconnection policy for smaller generators defined as having a capacity equal to or less than 20 MW.[48] According to FERC, the purpose of standardizing interconnection procedures was to (1) limit opportunities for transmission providers to favor their own generators, (2) facilitate market entry of generators and promote competition, and (3) encourage generation and transmission investments.[49]

Under Order 2003, procedures and rules governing the interconnection of large generators are provided in Appendix C, Standard Large Generator Interconnection Procedures (LGIP). Key steps to enable a generator to interconnect are summarized below.

- The generator initially submits an interconnection request to the transmission provider. Requests must include preliminary site documentation, expected in-service date, and a $10,000 deposit.

- After receiving a complete interconnection request, the transmission provider puts the request in its interconnection queue and assigns it a queue position. Queue positions are based on the date and time of receipt of requests. Queue positions determine the (i) order that the transmission provider performs interconnection studies and (ii) cost assignment responsibility for installing facilities to make interconnections.

- A scoping meeting is held between the transmission provider and generator to discuss potential points of interconnection and technical information.

[47] Order No. 2003, Standardization of Generator Interconnection Agreements and Procedures, 104 FERC 61,103, (July 24, 2003). Subsequent related orders include: Order No. 2003-A, 106 FERC 61,220 (March 5, 2004); Order No. 2003-B, 109 FERC 61,287 (December 20, 2004); Order No. 2003-C, 111 FERC 61,401 (June 16, 2005).
[48] Order No. 2006, Standardization of Small Generator Interconnection Agreements and Procedures, (May 12, 2005).
[49] Order 2003, p. 4.

- The generator enters into agreements with the transmission provider to perform a series of interconnection studies[50] to be performed by the transmission provider in sequential order.

Section 4 of the LGIP provides rules governing the interconnection queue. The general principles for a sequential first come, first served approach are specified in section 4.1. The queue position for an interconnection request is determined by the date and time of filing the request relative to other applicants. The queue position determines the order of performing the interconnection studies and the cost responsibility for facilities needed for the interconnection.

Section 4.2 provides an exception to first come, first served principle. The clustering option allows transmission providers discretion to study and pursue multiple requests in a common group. If a transmission provider elects to study requests in a cluster, it may take all requests over a period up to 180 calendar days (the "Queue Cluster Window") and study them together without regard to the underlying interconnection service. Transmission providers have additional discretion to set deadlines for interconnection studies as provided for in rules governing affected systems in section 7.4.

FERC envisioned clustering as a flexible alternative to facilitate coordinating interconnection requests with transmission planning. In discussing comments about clustering in Order 2003, FERC issued the following statement:

> Clustering is strongly encouraged in queue management and the Interconnection Study process for all Transmission Providers. We vigorously support the use of queue windows to manage the Interconnection Study process. . . Clustering (by queue position and electrical location) ensures that the regional expansion plan considers all uses of the Transmission System and enables

[50] (1) Interconnection Feasibility Study. A preliminary evaluation of the feasibility of the proposed interconnection. The generator must submit a $10,000 deposit for this study. The transmission provider must complete the study within 45 calendar days after signing the interconnection feasibility study agreement.

(2) Interconnection System Impact Study. A comprehensive analysis of the impact of the proposed interconnection on the reliability on the transmission provider's system and affected systems. The generator must provide the transmission provider with a $50,000 deposit. The transmission provider has 60 calendar days to complete the study after signing the agreement to perform the study.

(3) Interconnection Facilities Study. This study identifies facilities necessary to complete the interconnection, costs of those facilities, and the time necessary to interconnect the generator. The generator must submit a $100,000 deposit or monthly payments to the transmission provider.

(4) Optional Interconnection Study. This study or sensitivity analysis examines assumptions specified by the generator to identify possible network upgrades that may be required to transmission service. The generator must provide the transmission provider with a $10,000 deposit.

> expansion of the system to be accomplished in the most efficient manner reasonably achievable.[51]

Section 4.3 imposes restrictive constraints on the transferability of queue positions. A generator with a queue position may transfer its queue position to another party only if that party acquires the specific generating facility linked to the interconnection request and the point of interconnection does not change.

FERC apparently decided against structuring the queue position with property right qualities that would have permitted parties to buy and sell their queue positions in market transactions. FERC sided with commentators who worried that queue trading would unnecessarily increase the complexity of analyzing interconnection requests because of changing assumptions and the potential for adverse gaming opportunities.[52]

Section 4.4 provides conditions under which the generator may obtain modifications to the interconnection request without loosing its queue position. These provisions attempt to strike a balance between allowing minor modifications to not bump requests out of the queue, but not burdening transmission providers with significant changes that could lead to expensive revisions in preparing interconnection studies.

Small Generator Interconnection. In May 2005, FERC issued Order No. 2006 which provides new standardized interconnection procedures for small generators. Small generators are defined as having a capacity of 20 MW or less. Small generator interconnection requests generally impose a smaller burden on transmission providers and can often be completed in a shorter time period than larger generators. Representatives from small generator groups had urged FERC to adopt a separate interconnection queue for small generators and large generators. Small generators hoped to avoid the entanglement of longer study times associated with requests by large generators. FERC rejected this approach on grounds that a two queue approach would delay and complicate the process for transmission providers and that small generator requests may still move through the study process at a faster speed once the study process begins.[53]

Codes of Conduct. FERC issued Order No. 2004 to establish uniform standards of conduct to prevent transmission providers from giving undue preferences to their energy affiliates and ensure transmission is provided on a non-discriminatory basis.[54] The standards of conduct in Order 2004 are consistent with FERC's desire to functionally separate transmission services from other aspects of integrated utilities and also tightened earlier standards of conduct created in Order 889.

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[51] Order 2003, p. 37-38.
[52] Order 2003, p. 38-39.
[53] Order No. 2006, p. 52-53.
[54] Order No. 2004, Standards of Conduct for Transmission Providers, 105 FERC 61,248 (November 25, 2003).

Under Order 2004, an integrated utility must create tighter firewalls between employees in the transmission division and employees in other divisions and with energy affiliates. In particular, Section 358.5 requires that transmission providers limit access of information and communications to other employees to information that is available on the OASIS system.

While the objective is to limit the danger of undue preferences and discrimination, there is a corollary loss of communication and coordination that might otherwise occur between transmission employees and other employees. This restriction raises potential coordination complications between employees in the resources planning division and experts in transmission planning belonging to a common integrated utility.

<u>Interaction of Transmission Planning and Generator Interconnection Rules</u>

Over the past five years, three important initiatives have been influencing the future direction of electricity markets in the Western Interconnection. First, transmission planning efforts have developed at the both the interconnection-wide level and the sub-regional planning level. Second, state policy makers have supported greater use of renewable energy and enacted renewable portfolio standards (RPS) in several states. Third, Western utilities have been engaged in a new wave of resource planning and increasingly identifying economical clean and diversified resources. These three drivers would suggest a future path that increases the use of clean and diversified energy and develops new transmission expansion in a coordinated fashion with new generation additions.

Current queuing policies designed to promote open access transmission, however, may inadvertently slow down or possibly short-circuit these policy and planning efforts in the West. The rigidity of queuing rules could interfere with the implementation of the best made plans and policies.

Western Governors and others have been pressing for open, pro-active, interconnection-wide transmission planning. The largest uncertainty in transmission expansion planning is the location of new generation. Load growth and the transmission topology can change over the planning period. However, these uncertainties are smaller than uncertainties associated with the location, size and type of new generation that may be constructed. The ability to develop a plan that coordinates new generation with optimizing transmission expansion requires modeling the entire system. Practical experience in these planning efforts also indicates that there is an iterative process between transmission and generation decisions in finding optimal solutions.

An important lesson from these transmission planning efforts is the need to coordinate new transmission development with the LSE acquisition of least cost portfolios of generation resources. Certain resources like wind, geothermal and coal are very dependent upon future transmission expansion. Planned transmission expansion to targeted resource rich regions is important in developing least cost regional solutions to meeting western demand for electricity.

Open Season. An open season process can be a complement or an alternative to the sequential queue process. The open season has been used for years in the natural gas industry to identify the demand for new pipeline capacity. FERC policy embraces the use of the open season method in the natural gas industry.[55] The open season process entails more than what current FERC rules provide in clustering of interconnection requests. Clustering gives transmission providers discretion to study a group of interconnection requests submitted over a 180 day period. Individual requests are grouped and evaluated in a common batch. Clustering does not include, however, other important features of an open season process such as the transmission provider plans for a specific transmission project and solicitation of bids for rights to transmission services. The open season process encourages pro-active planning to anticipate demand for transmission services and provides a mechanism to test market demand for such services before transmission providers are financially committed to pursue projects.

EPACT Congestion Study. The Energy Policy Act of 2005 requires that DOE conduct a study of electric transmission congestion one year after enactment and every there years thereafter.[56] Congress instructed DOE to consult with states and any appropriate regional entity in developing congestion studies. After reviewing congestion studies, DOE has authority to designate national interest electric transmission corridors. In such designations DOE may consider whether—

> "(A) the economic vitality and development of the corridor, or the end markets served by the corridor, may be constrained by lack of adequate or reasonably priced electricity;
> (B)(i) economic growth in the corridor, or the end markets served by the corridor, may be jeopardized by reliance on limited sources of energy; and
> (ii) a diversification of supply is warranted;
> (C) the energy independence of the United States would be served by the designation;
> (D) the designation would be in the interest of national energy policy; and
> (E) the designation would enhance national defense and homeland security."[57]

In the Western Interconnection, a collaborative effort by the Western Electricity Coordinating Council (WECC), the Committee on Regional Electric Cooperation

[55] The application of an open season process for transmission would involve the following steps. A transmission provider announces that it will be holding an open season where potential customers would indicate their interest in obtaining transmission services. At some point in the process, the transmission provider would provide detailed plans for a proposed expansion and solicit bids for reserving future transmission rights. Potential customers would then respond by submitting bids backed by financial commitments. The resulting bid response for the proposed project would give the transmission provider certainty about the level of demand for the project and a pool of funds to proceed with the project. In effect, the open season process provides a pseudo-market mechanism to reveal the demand for transmission services to the transmission provider in an open and non-discriminatory manner.
[56] Energy Policy Act of 2005, Section 1221.
[57] Energy Policy Act of 2005, Section 1221.

(CREPC), and SSG-WI has proposed to offer DOE results of existing and current transmission planning studies as a package to meet statutory requirements to study congestion in the West. Specific components of the Western Interconnection package would include analysis of historic congestion on major transmission paths, SSG-WI modeling analysis of future congestion in 2015 under a reference case and assumptions of the WGA Clean and Diversified Energy initiative, and other sub-regional studies of transmission congestion.

The Transmission Task Force identified the following recommendations to improve and enhance future transmission planning efforts, an essential first step to expanding the grid.

Recommendations: Transmission Planning

Recommendation 7: Governors and state regulators should support a regional approach to transmission planning[58] with the following specific actions:

7(a): Resources and Institutions. Governors should (i) ensure resources to enable state participation in regional transmission planning, and (ii) urge the industry and FERC to strengthen and make sustainable the existing pro-active, transparent interconnection-wide and sub-regional transmission planning processes.

7(b): Acknowledge Regional Impacts. Governors and state legislatures should review, and if necessary, amend state laws to require PUCs and public power boards to consider regional transmission needs.[59] In addition to studies by project proponents, PUCs should consider whether projects are consistent with regional transmission expansion planning studies and complement state energy policy.

7(c): Planning and Regulatory Findings. Governors and state regulators should support goals of a regional planning capability that can yield critical information for stakeholders and regulators to allow rigorous evaluation of large long-term investments in transmission including: (i) identification of regional

[58] Consistent with a policy adopted by the National Association of Regulatory Utility Commissioners, this report envisions a regional transmission planning process to perform the following functions: (a) take into account fuel diversity including renewables resources; (b) recognize the need for new investment in generation and transmission facilities that provides adequate reserve margins; (c) assure that reliability is not compromised by resource imbalances; (d) reduce any decisional role for entities with unreasonable generation or transmission market power; (e) include broad public participation and collaboration among market participants and third party participation in offering competitive alternatives such as demand-side and distributed generation options; and (f) use transmission planning to address reliability and operational consistency. NARUC's National Electricity Policy (http://www.naruc.org/displaycommon.cfm?an=1&subarticler=29)

[59] The authority of PUCS and its institutional relationship with the Governors varies among states. For example, some PUC commissioners are elected officials and their responsibilities are specified in the state constitution. (e.g., Arizona, Montana and New Mexico). In other states, PUC commissioners are appointed by the governor and operate within the executive authority.

beneficiaries of potential projects; (ii) identification of economically efficient investment projects as the basis to support a regulatory determination that a project is in the public interest and a prudent investment; (iii) ex ante evaluation of investment prudence to provide greater certainty about cost recovery, and thereby reduce the risk exposure for project developers and investors.[60]

7(d): Synchronize Planning. Governors and state regulators should encourage synchronizing regional transmission planning efforts to resource acquisition plans of load serving entities (LSE) and plans of generators. LSE resource planning efforts within an area need to be coordinated to the same schedule so that generating options that require significant new transmission will be considered in LSE resource plans.[61]

7(e): Communication Codes of Conduct Flexibility. FERC should clarify code of conduct rules that would allow transmission and resource planning functions of vertically integrated utilities to discuss transmission needs associated with new generation being considered to serve the utility's load provided that such communication is transparent to outside parties and part of a state-approved resource planning and acquisition process.

Recommendation 8: States Role. Governors should take a leadership role in bringing together stakeholders and forging solutions to regional transmission needs, cost allocation, and siting where RTOs/ISOs do not exist. Where RTOs/ISOs do exist, states should be actively involved in regional planning, in order to build a common understanding of the range and impacts of possible solutions. To enable effective state participation, adequate funding should be provided for staff time.[62]

Recommendation 9: Queue Reform. Governors should request that FERC convene a technical conference with Western state PUCs, LSEs, generation developers, and transmission owners to develop needed reforms of interconnection and transmission queuing processes to acknowledge outcomes of regional transmission planning studies and complement state energy policy.

Recommendation 10: Open Season. Governors and state regulators should encourage the use of an open season process by project developers as a means of demonstrating demand for and value of new transmission projects, and encourage expanded project participation. Recent open season proposals by NorthWestern Energy, BPA, SWAT, and Western demonstrate how open season processes can be adapted and applied to proposed transmission projects.[63]

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[60] Wind Task Force, p. 64.
[61] Wind Task Force, p. 60.
[62] Keystone, p. 4.
[63] Wind Task Force, p. 65.; PPIW.

b. Cost Allocation and Cost Recovery for Transmission Investment

Background

The federal government and state governments regulate different areas of the electric industry. The Federal Energy Regulatory Commission (FERC) regulates interstate electric wholesale transactions and sets wholesale transmission tariffs. State regulatory commissions (PUCs) have exclusive jurisdiction over bundled retail rates within their respective states. FERC and states have limited jurisdiction over public power utilities (rural cooperatives, municipalities, generation and transmission cooperatives, federal power marketing administrations).

Many states require investor owned utilities (IOUs) to plan for resource acquisitions and transmission expansion through an integrated resource plan (IRP) process. States generally require that the transmission project sponsor obtain a certificate of public convenience and necessity (CPCN) by demonstrating the need and public interest of their proposed projects. States allow jurisdictional transmission owners to recover the portion of prudent transmission costs used to provide retail service through the retail price of electricity set by the PUC and paid by electricity customers. The balance of transmission cost recovery is through wholesale transmission rates, or tariffs, set by FERC.

Prior to 1992, most electric utilities operated as vertically-integrated monopolies and were responsible for coordinating all generation, transmission and distribution functions within their respective service territories. After passage of the Energy Policy Act of 1992 and Order 888/889 in 1996, IOUs (and some public power entities) became functionally separated between generation and transmission, and faced competition in the generation sector. FERC encouraged the formation of RTOs/ISOs to manage regional electrical networks and to plan and coordinate transmission investments. With the exception of portions of western states covered by the CAISO, the MISO, ERCOT, and SPP, the movement towards RTOs in the rest of the West has stalled for now. Absent cost recovery mechanisms defined by broad regional transmission organizations in the West, state PUCs, and governing bodies of public power entities, continue to have decision-making responsibility about cost recovery for projects in their respective states.

FERC Policy. New transmission that connects generators to the grid are called generation tie-lines i.e., lines from the generator to the first point of interconnection with the grid. FERC generator interconnection rules provide that interconnecting generators bear the full cost of the generation tie-lines.[64] Network upgrades are defined as the additions, modifications, and upgrades to the transmission system at or beyond the point of connection to the grid to accommodate generators to the system. The full cost of network upgrades for generator interconnection is borne by and rolled into transmission rates of transmission owners. Transmission owners, however, may require interconnecting generators to provide upfront funding for network upgrades and then

[64] Standardization of Generator Interconnection Agreements and Procedures, 104 FERC ¶ 61,103 (2003) ("Order 2003").

credit the funds, with interest, back to generators over time following commercial operation of generators. This type of cost allocation is known as "participant funding". This funding and credit back policy places the developmental risk on the interconnecting generator rather than the transmission owner or its customers. FERC interconnection policy does not draw a distinction between new transmission required for reliability reasons and transmission developed for economic reasons. Critics of participant funding argue that this cost allocation mechanism creates more uncertainty for potential investors, encourages "freeriders" to wait until others fund needed upgrades and thereby encourages delays.[65]

State Policies. For transmission developed outside of a request for interconnection from generators, cost allocation is handled differently in different regions. Western states generally allocate transmission costs based on principles of cost causation, beneficiary pays, and relative use. Cost causers are parties that cause transmission costs to be incurred. Beneficiaries are those parties deriving direct benefits from transmission projects. Costs of new transmission would be allocated to identified cost causers or beneficiaries, or both based on their relative use of the total benefits created by a project. Customers in a local area that benefit the most from a new facility would pay more than customers in another region that derive little or no benefits from a project. This approach provides price signals promoting the efficient level of new transmission investments relative to other potential investments in the system.

In contrast, other regions such as New England[66] and Texas[67] have adopted cost allocation policies that share equally or socialize costs for transmission projects with regional purposes or where beneficiaries can not be clearly identified. Transmission costs are socialized in these regions by rolling costs into general rates faced by all users. Proponents of socializing transmission costs point out that it is very difficult to accurately identify current beneficiaries of transmission investments. Over time, the level and distribution of benefits from transmission becomes even more diffuse since incremental transmission investments improve overall reliability to the system, and interactions of

[65] American Public Power Association / Transmission Access Policy Study Group, APPA/TAPS Position Paper: Effective Incentives to Getting New Transmission Built, (http://www.tapsgroup.org/sitebuildercontent/sitebuilderfiles/030918finalincentives.pdf).

[66] Order on Complaint and the Proposed Amendments to the NEPOOL Tariff and the Restated NEPOOL Agreement, 105 FERC ¶ 61,300 (2003) (Docket No. ER03-1141-03) The New England Power Pool (NEPOOL) and the New England ISO adopted a default cost allocation mechanism that socializes transmission costs where beneficiaries could not be clearly identified and upgrades produce regional benefits. Transmission facilities rated 115kV and higher are eligible for regional cost support and this covers approximately 95% of the existing pool of transmission facilities in New England. The New England policy calls for participant funding for elective upgrades, upgrades for generator interconnections, merchant transmission facilities, and local upgrades.

[67] See Texas Public Utility Regulation Act, §35.004 (Texas statute on the socialization of transmission costs in ERCOT) (www.puc.state.tx.us/rules/statutes/Para03.pdf); and Texas PUC Substantive Rule 25.195(c), which is a generation interconnection rule with cost allocation based on a highway/driveway model. (Generators are responsible for facility costs from the generator to the interconnection (driveway). Transmission owners are responsible for all other costs for upgrades necessary to accommodate the requested transmission service (highway)) (www.puc.state.tx.us/rules/subrules/electric/25.195/25.195.pdf)

additions of new generation and other transmission projects alter the flow of electricity over the grid in complex and unanticipated ways.

Texas and Minnesota have recently enacted legislation to provide legal and regulatory incentives to build transmission in support of and prior to building of renewable generation. In Texas, SB. 20[68] authorized the public utility commission to require electric utilities to construct or enlarge transmission facilities to meet Texas RPS goals. The Texas public utility commission must designate renewable energy zones and develop a plan to construct transmission to those zones. SB 20 requires the public utility commission to issue a final order within 181 days of the filing of an application for certificate of public convenience and necessity to build transmission to meet RPS goals. Applications are automatically approved if the commission fails to act after 181 days. Additionally, SB 20 provides cost recovery incentives. Transmission projects supporting RPS goals shall be deemed used and useful, and prudent and includable in the rate base, regardless of the utility's actual use of the facilities.

In Minnesota, SF 1368[69] contains transmission provisions to support renewable energy development and to meet the Minnesota RPS goal. SF 1368 requires utilities to identify future transmission inadequacies in the transmission system, identify alternative means to address such inadequacies and submit transmission reports to the public utility commission. Utilities must determine necessary transmission upgrades to support development of renewable energy to meet the RPS conditions. Transmission projects determined to be necessary to support a utility's plan to meet RPS requirements would be deemed a priority electric transmission project and serve to satisfy a certificate of need. SF 1368 grants public utility commission authority to approve transmission cost adjustments for new transmission facilities deemed a priority transmission project. Such transmission tariffs would allow utilities to recover costs on a timely basis, allow a return on investment at a level most recently approved or another rate consistent with the public interest, and for a current return on construction work in progress.

Renewable Trunk-line. FERC's current policy is problematic for transmission expansion designed to develop location constrained resources such as wind and geothermal energy. Large transmission projects are needed to support many individual decentralized energy projects. One innovative approach to resolve this problem is a renewable trunk line concept as proposed by Southern California Edison (SCE) for its Tehachapi/Antelope transmission project. This proposal envisioned transmission expansion in advance of generator requests based on predictable growth of many independent wind generation projects in a designated concentrated area. The proposal avoids the pitfall of inefficient piecemeal studies required under current interconnection rules. Specific elements of the SCE proposal are summarized below:

[68] Texas Legislature SB 20, Legislative Session 79(1), signed by Governor Rick Perry on August 2, 2005, and effective on Sept. 1, 2005. Section 3 of SB 20 raised the Texas RPS goal to 5,880 MW of cumulative installed renewable capacity by 2015, and a target of 10,000 MW by 2025 (http://www.capitol.state.tx.us/).
[69] Minnesota State Legislature, SF 1388, Legislative Session 84, signed by Governor Tim Pawlently on May 25, 2005 (http://www.leg.state.mn.us/leg/legis.asp).

- Rolled-in rate treatment for high-voltage (220kV or higher) trunk-line transmission project costs necessary to integrate large concentrations of renewable generation resources located a reasonable distance from the existing grid. To be eligible for this treatment, large concentrations of renewable resources should be located in a limited geographic area.
- Permit rolled-in rate treatment and cost recovery for prudent costs for transmission facilities described above regardless of whether the full increment of forecast generation that would justify the upgrades commences commercial operations.
- Grant 100% cost recovery for prudent costs even if the transmission project is cancelled or abandoned either because there is insufficient generation development in the region or necessary regulatory approvals for project construction are not granted. Under current policy, FERC limits recovery from ratepayers to only 50% of the utility's prudently-incurred investment in abandoned or cancelled FERC-jurisdictional plant (facilities not completed and placed into operation).[70]

On July 1, 2005, FERC issued a split decision that rejected the renewable trunk-line features of the SCE proposal but accepted cost recovery features of 2 of the 3 proposed transmission system upgrades. The majority rejected the trunk-line feature on grounds that it was contrary to FERC policy on generation interconnection policies and that SCE did not establish system-wide benefits to all consumers of the transmission system.

Infrastructure Authorities. In 2004, Wyoming created the Wyoming Infrastructure Authority (WIA), a new hybrid quasi-state entity designed to facilitate the planning, financing, and permitting of new transmission facilities. The WIA has authority to own, operate and maintain high-voltage interstate transmission facilities. Within Wyoming, the WIA also has condemnation power to facilitate transmission expansion planning and siting. The WIA has authority to issue revenue bonds to raise capital to build transmission infrastructure it would own. The WIA is a new institution that will become involved in transmission planning and expansion. This creates opportunities to collaborate on transmission investments, to pursue partnerships with public and private entities, to begin to address siting and rights-of-way issues, and to explore creative financing and contracting.[71] Following the Wyoming example, Kansas[72]

Wind Task Force, p. 65-66.

[70] Rocky Mountain Area Transmission Study (RMATS), September 2004, p. 4-11. There is no statutory limit on this bonding authority for projects the WIA might own. The WIA also has the capability, within an outstanding bond cap of $1 billion,**}** to issue bonds to build transmission facilities owned by other entities. All WIA-issued bonds would be exempt from state taxation. Tax-exempt bond financing may reduce the cost of transmission projects compared to private-sector equity and debt financing. The WIA is constitutionally barred from issuing revenue bonds backed by the faith and credit of the State of Wyoming. This means for any WIA bond issuance to be successfully received by the financial community, the bonds will likely need to be secured by an expected revenue stream from the transmission investment. This security could take the form of subscription-type contracts with entities expected to use the transmission, a lease agreement with one or more utilities agreeing to take transmission capacity, or other means.

[72] In 2005, the Kansas Legislature enacted House Bill No. 2263 which created the Kansas Electric Transmission Authority. The legislation vested the Kansas Electric Transmission Authority with powers to

and South Dakota[73] adopted similar infrastructure authorities. New Mexico and Montana legislatures have considered infrastructure authorities in the last session.

Western Area Power Administration. Western, acting at the direction of the Secretary of Energy, provided facilitation services that resulted in the upgrade of the critical Path 15 transmission constraint in California. During the period 2001-02, transmission bottlenecks in Path 15 enabled some parties to exercise market power that contributed to the meltdown of the state's power market. Western partnered with the state, Trans Elect, and transmission owners to plan, finance, and construct the long-needed Path 15 upgrade, which was dedicated by Governor Schwartzenneger in December, 2004. Western has also agreed to facilitate the Tot 3 upgrade between Cheyenne and Denver in an MOU with the Wyoming Infrastructure Authority and Trans Elect. Western has the power of eminent domain for transmission routes throughout its service territory, which covers most of the WGA western region.

EPAct 2005 Incentives. The Energy Policy Act of 2005 included numerous provisions designed to provide incentives for new transmission facilities. Section 1241 instructs FERC to adopt new rules within one year that provide incentive-based rates for transmission of electricity, a rate of return on equity to attract new investment in transmission facilities, encourages deployment of transmission technologies to increase capacity and efficiency, and allows for recovery of costs associated with reliability provisions and siting of new facilities. Section 1242 authorizes FERC to approve a participant funding plan that allocates costs related to transmission upgrades or new generator interconnections subject to specified conditions. Two additional provisions provide tax benefits for transmission owners. Section 1308 establishes a 15-year recovery period and class life of 30 years or more for transmission lines (67 KV or more) put into use after April 11, 2005. Section 1311 allows transmission owners to utilize a net operating loss carryover for five years on expenditures attributable to electric transmission property.

The proposals described below provide opportunities to address the critical problem of coordinating transmission investments with generators of clean and renewable energy. These proposals assume that no new RTOs will be adopted in the foreseeable future.

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plan, finance, construct, develop, acquire, own, and dispose of transmission facilities. Additional financial powers include the ability to enter contracts with the Kansas Development Finance Authority to issue bonds and provide financing for construction, upgrades of transmission facilities and acquisition of rights-of-way.

[73] The South Dakota Legislature adopted HB No. 1260 during its 2005 Session to create the South Dakota Energy Infrastructure Authority. The South Dakota Energy Infrastructure Authority has powers to finance, construct, develop, maintain and operate new or upgraded transmission facilities. It may own, lease, or enter into partnerships for such facilities. The South Dakota Energy Infrastructure Authority may issue bonds to finance transmission facilities up to one billion dollars, however, the state legislature must approve the issuance of such bonds.

Recommendation: Cost Allocation and Cost Recovery

Recommendation 11: Presumption of Prudence. Governors should urge State regulators to adopt policies, and promote legislation if necessary, to establish a tiered standard of review for prudency and application of transmission incentives for transmission expansion costs featuring a lower standard for screening studies and planning, a moderate standard for permitting and the acquisition of rights-of-way, and a higher standard for construction costs. This tiered standard for review of prudent costs and use of financial incentives will reduce the risk to transmission developers associated with recovering the cost of scoping and planning of potential transmission expansion projects. This will encourage transmission developers to evaluate and plan potential expansion which are, relative to generation costs, low cost investments. States should work together to develop common standards for review of prudent costs and use of incentives.

Recommendation 12: Public Interest and Regulatory Incentives. Many western states have adopted renewable portfolio standards (RPS) to stimulate greater use of renewable resources. States that have adopted mandatory RPS goals have expressed a general public interest in expanding the use of clean renewable energy. Regulatory commissions should acknowledge these public interest benefits as system-wide benefits, and make corollary public interest findings for cost effective transmission projects that will enable states or the region to meet its energy policy goals. These public interest findings would provide a factor for consideration of:

- A certificate of public convenience and necessity for construction of transmission projects necessary to meet state energy goals and other necessary rulings to ensure efficient siting of new transmission and generation facilities;
- Rolled-in rate treatment for transmission projects deemed necessary to meet state energy goals;
- Expedited and streamlined recovery of construction expenses for transmission projects deemed necessary to meet state energy goals.
- Modification of FERC queue rules to permit flexibility and coordination of multiple generation and transmission projects that are necessary to meet state energy goals.[74]

Recommendation 13: Transmission in Advance of Clean and Diversified Generation. Urge Governors, state regulators, state legislatures, and FERC to expand transmission in advance of generation to enable the modular development of location-constrained, clean and diversified resource areas to meet cost effective RPS, IRP and state goals. Such actions should build upon recent Texas and Minnesota legislation for new transmission to major renewable resource areas and the renewable trunk line (Tehachapi) model for new transmission to major renewable resource areas.

[74] Wind Task Force, p. 65.

Recommendation 14: Coordinated Cost Allocation Guidelines. States, stakeholders, and RTOs/ISOs should develop a region-wide set of guidelines on cost allocation for new transmission facilities that limits case-by-case review of allocation decisions.[75]

a. ***Coordination of State Regulatory Commissions.*** States should take steps to coordinate their respective regulatory reviews of multi-state transmission projects in a manner that builds upon existing regulatory principles and respects the public interest of individual states. Governors can improve regulatory coordination by the following actions.
   - Organize a convention of western state regulatory commissions that would develop common principles for cost allocation and recovery for multi-state transmission projects. This convention would establish a process that would lead to a memorandum of understanding or regional protocol among western states. Potential role models for this multi-state coordination effort include the Western Governors' Transmission Siting Protocol, the Midwest Governors' Regional Electric Transmission Protocol, and the Multi-state Protocol by states in the PacifiCorp service area.
   - Adopt a common western procedural process that coordinates regulatory commission reviews of multi-state projects. This process would identify and coordinate applications, forms, factual records, analyses and deadlines that a project sponsor encounters in seeking regulatory approvals for a multi-state transmission project.[76]

b. ***Develop Multi-State Pricing Principles.*** States in a region, through their regulatory commissions and after hearings, enter into a memorandum of agreement (MOA) adopting pricing principles, and jointly file such an MOA at FERC and request the Commission's endorsement. These principles would then be used as criteria for decision-making for any applications for transmission cost recovery received by regulatory commissions within the region, thus providing a degree of clarity and consistency in regulatory treatment. These principles could also be included in tariff filings made by FERC-jurisdictional utilities.

Recommendation 15: Transmission Incentives. Governors and state legislatures should explore and consider transmission incentive mechanisms in collaboration with federal efforts to implement Section 1241 of the Energy Policy Act of 2005.

[75] Keystone, p. 6.
[76] Wind Task Force, p. 64.

The Governors should urge FERC and state PUCs to form joint State and FERC panels to adopt appropriate mechanisms that will enable cost recovery of transmission investments. These panels could drive agreements between state and federal regulators, transmission developers and their investors that would provide cost recovery assurances sufficient to induce development of needed infrastructure. The panels should also explicitly consider the risks and need for financing incentives such as the following[77]:

a. Forms of pre-approval, higher rates of return on transmission investments, and quicker cost recovery of transmission investments.[78]
b. Transmission pricing policies that (a) allow for cost recovery of fixed and variable costs and a reasonable return on transmission investment, (b) ensure, to the extent practicable, that cost responsibility follows cost causation, (c) minimize the potential for cost shifting, (d) permit the recovery of all prudently incurred transition costs, and (e) promote efficient siting of new transmission and generation facilities.[79]
c. Avoid conflicting federal and state regulatory policies that can result in unrecoverable, trapped costs. FERC and states must ensure that necessary regulatory mechanisms are in place to allow for full and timely recovery of all prudently incurred costs and avoidance of trapped costs.[80]
d. Coordinate state policies with FERC to allow full recovery of all prudently incurred costs to design, study, pre-certify, and permit transmission facilities. FERC should amend its rules to allow full recovery of the prudently-incurred costs of abandoned transmission projects.[81]
e. Currently, most jurisdictions do not allow utility rates to include a return on construction funds invested in projects until the project goes into operation. Instead, these costs are carried by the utility and added to its rate-base, along with the carrying costs incurred during construction, when the project is put in service. FERC should allow utilities to include construction work in progress in rate base (in lieu of Allowance for Funds Used During Construction (AFUDC)) as this will encourage transmission construction through improved cash flow and greater rate stability.[82]

[77] Western Governors' Association, Financing Electricity Transmission Expansion in the West: A Report to the Western Governors, February 2002, p. 4 (http://www.westgov.org/wga/initiatives/energy/final_rpt.pdf).
[78] RMATS, p. 4-10.
[79] Edison Electric Institute, EEI Principles on Transmission Investment, March 17, 2005 (EEI Principles) (http://www.eei.org/industry_issues/energy_infrastructure/transmission/eei_tranmission_principles_5_10.pdf?ObjectID=35619).
[80] EEI Principles.
[81] EEI Principles.
[82] EEI Principles.

Recommendation 16: Engage the Infrastructure Authorities and Western. Governors, state regulators and stakeholders should support and collaborate with state infrastructure authorities that have been created to facilitate transmission expansion, and with Western, which brings a proven track record of transmission upgrades. These entities provide new opportunities for transmission expansion using broad powers to facilitate, finance, plan, site, build and commission new transmission.[83]

Recommendation 17: Seams Between Contract and Tariff-Based Transmission Systems: The institutional ownership and operations of the transmission grid are currently divided between systems based on the contract model and systems based on the tariff model (i.e. RTO/ISO system). These two models utilize different and sometimes inconsistent methods to expand and operate the transmission system. In the West, these inconsistent methods can paralyze efforts to meet the need for transmission services. Each model has advantages and disadvantages. For example, the contract model enables transmission users to buy a portion of new line and derive benefits of ownership that include an improved balance sheet and a greater ability to borrow funds for construction of new transmission. An open season approach can help determine the market demand for new lines. Proponents of the tariff model claim benefits associated with operational efficiency and comprehensive planning over the entire system. Since it is unlikely that one model will emerge in the near term, the Governors urge all parties to develop workable agreements at the seams between these different models. The Governors:

a) Request that WECC provide a forum for sharing information on successful agreements to resolve issues at the seams between the different models;
b) Urge FERC to provide flexibility to ISOs/RTOs to reach workable agreements with entities operating under the contract model to avoid problems at the seams; and
c) Where such agreements cannot be reached, the Governors urge all parties to utilize WECC's arbitration process.

c. Transmission Siting and Permitting

Background

The siting and permitting of new transmission can be a very contentious process. The siting of interstate transmission lines may be particularly challenging in cases where states along the route do not derive benefits from the project. States have generally exercised siting and permitting authority over electric transmission lines. Congress recently enacted new provisions to pre-empt states siting of transmission under certain

[83] RMATS, p. 4-11.

conditions. Depending upon the implementation of the new federal policies, future siting of transmission may well be determined by FERC rather than state agencies.

Western states have different approaches to siting and permitting transmission facilities. State public utility commissions generally must issue a certificate of public convenience and necessity (CPCN) prior to construction. Siting authority may reside among state agencies or county governments. For example in Montana, transmission siting is centralized in the Department of Environmental Quality rather than the Montana Public Service Commission. In Colorado, Utah and Idaho, there is no single state agency responsible for siting transmission facilities; primary siting authority exists in county governments. In Wyoming, the Public Service Commission must certify transmission lines built by public utilities.

Western Governors created a Transmission Permitting Protocol to enable federal, state and provincial permitting agencies to collaborate in the review of proposed interstate transmission lines. The WGA Transmission Permitting Protocol has been signed by 12 governors (AK, AZ, CA, CO, ID, MT, NV, NM, OR, UT, WA, WY) the Premier of Alberta, and four federal agencies (DOE, DOI, USDA, CEQ). The Protocol has not yet been tested, as no new interstate transmission lines have been proposed. The Midwest Governors' Electric Transmission Protocol provides a similar framework to address coordination of siting and permitting efforts in the Midwest states and Manitoba. Successful implementation of the Protocol will require political commitment and adequate resources to state agencies to enable them to participate in project review teams that would be created when the Protocol is triggered for a specific interstate transmission project.

Historically, one of the major challenges to siting new transmission in many parts of the West has been securing the necessary permits to cross federal lands. The federal government is the largest land owner in the West and almost every long distance transmission line in the Western Interconnection and in Alaska will cross federal lands.

The Energy Policy Act of 2005 establishes new federal authority to preempt state permitting processes applicable to interstate transmission lines. Section 1221 authorizes the Department of Energy to designate congested transmission areas as national interest electric transmission corridors. If a state takes longer than one year to approve an application for construction or modification of a transmission line in a national interest electric transmission corridor, the applicant can apply to FERC and obtain a federal permit for construction that preempts state permits. FERC can also preempt if the state imposes conditions on the project that make the project not economically feasible or if the conditions imposed undermines the project's ability to significantly reduce congestion. If the state or another entity does not have authority to approve siting of transmission facilities[84] or consider the interstate benefits of the transmission facility, then FERC has authority to issue a permit. Applicants that obtain federal permits for

[84] For example, if state law allows the granting of eminent domain to incumbent utilities only, any other party seeking to build transmission in a "national interest transmission corridor" can bypass the state and apply directly to FERC for eminent domain.

transmission will also gain authority to utilize eminent domain powers to obtain right-of-way across private land. Section 1221 designates the Department of Energy as the lead agency to coordinate all federal permits, certificates, opinions and other matters related to the proposed transmission project.

Section 1221 allows states to counter the expanded FERC authority by forming an interstate compact of three or more contiguous states to establish a regional transmission siting agency. The regional siting agency would have power to review, certify and permit siting of transmission facilities. FERC would not have authority to issue permits in states that are members of a regional siting agency compact so long as compact members are in agreement on a project.

The Energy Policy Act of 2005 also contains provisions to facilitate transmission across federal lands. Section 368 requires multiple federal departments (DOI, USDA, DOE, DOC, DOD) to designate corridors on western federal lands for pipelines (oil, gas, hydrogen) and electric transmission and carry out environmental reviews for such corridors in two years. Section 372 calls upon the Secretaries of Energy, Interior, Agriculture and Defense to enter into a memorandum of understanding to coordinate federal authorizations and environmental reviews for utility facilities, a term defined to include electric transmission facilities. The memorandum of understanding should lead to a unified right-of-way application form, a standard administrative procedure for processing right-of-way applications, and preparation of a single environmental review document.

While the designation of corridors will be useful, such designations must not preclude the expeditious processing of right-of-way applications across federal lands that fall outside corridors. It is very difficult to accurately anticipate the location of load growth and the sites of new generation decades in advance, which is what corridor designation seeks to achieve. It would be helpful if generation developers provide information to federal land management agencies and regional transmission planning processes on the location of potential generation sites and potential markets as soon as possible and not wait until a formal project application is submitted.

Recommendations: Siting and Permitting

Recommendation 18: The Governors have a critical opportunity to shape and influence transmission siting and permitting policy at the state, interstate, and federal level as described below.

18(a): Implementing the Transmission Permitting Protocol. Governors should ensure that there are resources and political commitment to successfully implement the WGA Transmission Permitting Protocol and the Midwest Electric Transmission Protocol for new interstate transmission proposals.[85]

[85] Wind Task Force, p. 68; PPIW.

18(b): Interstate Compact for Siting. Governors should consider and evaluate the option of forming an interstate compact for the creation of a regional siting agency pursuant to Section 1221 of the Energy Policy Act of 2005. An interstate compact would ensure that states joining the compact would retain authority to review and permit new interstate transmission facilities without the threat of federal preemption.

18(c): State Coordination of Siting. Governors should encourage consistent siting processes within their state through the use of standardized applications, joint data and studies, coordinated schedules and deadlines, and other mechanisms, where possible.

Recommendation 19: Federal Land Coordination. Governors should encourage Congress to provide resources to federal land management agencies to meet the requirements of Section 368 of the Energy Policy Act of 2005, and to: (1) adequately catalogue existing rights-of-way and corridors across federal land, including any opportunities to expand transmission capabilities within existing rights-of-way and corridors; (2) manage existing rights-of-way to prevent unintended consequences of land use decisions that would limit expansion of transmission capacity; (3) evaluate and designate transmission corridors; and (4) expeditiously decide on right-of-way applications that may fall outside of designated corridors. The Governors should direct state agencies to participate in the Section 368 process of designating energy corridors on federal lands, and collaborate on designation of corridors on state lands and encourage development of contiguous corridors on other lands.

APPENDIX A

Analysis of Transmission Needed in the Western Interconnection

In the Western Interconnection a different approach to evaluating the need for new transmission was used. The Seams Steering Committee-Western Interconnection[86] offered to model CDEAC generation scenarios as an initial screening of what new transmission would be needed to support the generation resulting from the CDEAC recommendations.

TO BE ADDED: DETAILED DESCRIPTION OF SCENARIOS, PROCESS USED TO IDENTIFY AND EVALUATE TRANSMISSION TO SUPPORT THE SCENARIOS AND A COMPARISON OF THE OPERATING AND CAPITAL COSTS AND BENEFITS OF THE SCENARIOS WITH THE REFERENCE CASE.

[86] The Seams Steering Group-Western Interconnection (SSG-WI) is comprised of the filing utilities for the proposed GridWest and WestConnect RTOs and the California ISO. SSG-WI's interconnection-wide transmission planning effort is an open planning process open to all parties. It uses a public data base and ABB's GridView production cost model. SSG-WI produced its first interconnection-wide transmission study in 2003. In the fall of 2005, SSG-WI developed an updated reference case. In addition, SSG-WI contracted with ABB to run the CDEAC scenarios and compare those scenarios with the reference case.

APPENDIX B

Analysis of the Transmission Needed in the Eastern Interconnection and ERCOT

MISO Transmission Expansion

Two WGA states, North Dakota and South Dakota, are part of the Eastern Interconnection within the Midwest ISO (MISO). The CDEAC Transmission Task Force draws upon studies by MISO to assess the transmission required to accommodate new generation recommended by the CDEAC fuel task forces (wind, solar, biomass, geothermal and coal).

The Wind Task Force identified significant wind resources in North Dakota and South Dakota that would require new transmission facilities. The Wind Task Force postulated three scenarios of wind development. In the medium case (Scenario 2), new wind energy development would be 500 MW in North Dakota and 750 MW in South Dakota by 2015. Under the high case (Scenario 3), wind energy generation rises to 2,250 MW in North Dakota and 2,250 in South Dakota by 2015.[87] The Biomass Task Force assumed that future biomass generation would be through distributed generation sources or located close to the grid and therefore would not need significant changes to the transmission system. The Geothermal and Solar Task Forces did not identify significant geothermal and solar resources in North Dakota and South Dakota that would require new transmission. The Coal Task Force has not produced a recommendation for future coal generation. Given the CDEAC task force recommendations, the Transmission Task Force draws upon MISO's analysis of future transmission expansion to tap as much as 2,250 MW in North Dakota and 2,250 MW in South Dakota.

The MISO Transmission Expansion Plan 2003 (MTEP-03)[88] analyzed a base case and three alternative scenarios: high gas scenario (including wind and minimal wind sub-scenarios), high coal/balanced scenario, and high wind scenario. The base case postulated 282,679 MW of generation and a base transmission configuration reflecting planned and proposed projects by transmission owners. The high gas scenario added 41,500 MW (84.4% gas, 7.8% coal, and 7.8% wind) of new generation to the base case. The high coal/balanced scenario added nearly the same amount of new generation (38,069 MW) as the high gas scenario but with a larger portion from coal (73.7% gas, 26.3% coal and 0% wind). The high coal balanced scenario replaced 6,000 MW of gas generation with 6,019 MW of coal generation. MTEP-03 evaluated the high gas and high coal/balanced scenarios with base case transmission assumptions.

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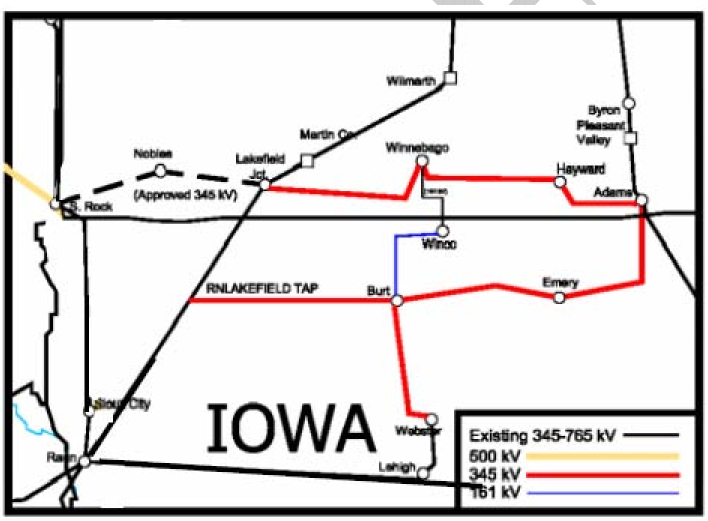
[87] Since the release of the Wind Task Force Draft Report 9-06-05, staff review of the ND and SD wind energy MW forecasts will be revised upward to 2900 MW for ND and SD in Scenario 3 based on the MTEP-03 findings at p. 297.

[88] Midwest ISO Transmission Expansion Plan 2003, June 19, 2003, (http://www.midwestiso.org/plan_inter/mtep3_archive.shtmlhttp://www.midwestiso.org/plan_inter/documents/expansion_planning/MTEP%202002-2007%20Board%20Approved%20061903.pdf).

The MISO high wind scenario postulated 8,640 MW of wind generation across nine Midwestern states, including 2,900 MW in North Dakota and 2,900 MW in South Dakota. The MTEP-03 analysis showed that the base case transmission assumptions could not accommodate the high wind scenario along with an anticipated coal plant located in Emery, Iowa. MISO developed two transmission expansion plans for the high wind scenario as part of its Northwest Area Exploratory Plans: (1) #3 Iowa and S. Minn. 345 kV and Dakotas 500 kV; and (2) #4 Northwest 345 kV Expansion and Dakotas 500 kV.

The Iowa and S. Minn. 345 kV and Dakotas 500 kV plan included a 500 kV line upgraded from 345 kV from Antelope (ND coal fields) to Broadland (Huron, SD), and a new connecting 500 kV segment to Split Rock (Sioux Falls, SD). New and upgraded 345 kV lines would continue east from Split Rock across southern Minnesota through Nobles, Lakefield Junction, Winnebago, Hayward and Adams. The 345 kV line would turn south and proceed through northern Iowa. A map of a portion of the #3 Iowa and S. Minn. 345 kV and Dakotas 500 kV plan is shown below.



#3 Iowa and S. Minn. 345 kV and Dakotas 500 kV Plan, MTEP-03

The second transmission plan, (2) #4 Northwest 345 kV Expansion and Dakotas 500 kV, builds upon the Iowa and S. Minn. 345 kV and Dakotas 500 kV plan and added additional 345 kV lines. Three 345 kV lines traverse across the Dakotas into Minnesota and funnel energy into the Minneapolis load center.

#4 Northwest 345 kV Expansion and Dakotas 500 kV, MTEP-03

The MTEP-03 analysis found that adding new transmission under both plans generally reduced constraints at key bottleneck locations in the region, provides small gains with lower congestion costs, and improved the capacity utilization of wind and coal generators. The two plans did not completely resolve congestion problems, especially in the west and northwest of this region where large wind energy development was postulated. Further refinements of the plans apparently would improve the results but were not undertaken for MTEP-03.

MTEP-03 evaluated economic benefits of the two transmission plans relative to a base case under different assumptions for natural gas prices ($3.34/mm Btu reference case and $5.00 high gas case assuming $2001), and three generation scenarios (high gas, high coal/balanced, and the high wind). The annual levelized cost of the two transmission plans are $132 million for the Iowa-Southern Minnesota plan and $379 million for the Northwest 345 kV & Dakotas 500 kV plan.

The MTEP-03 analysis calculates the benefits of reduced energy costs from new transmission and development of new wind and coal generation. As shown below, the combined benefits of the high wind scenario with high gas prices rise to $444 million for the Iowa-Southern Minnesota plan and $478 million for the Northwest 345 kV & Dakotas 500 kV plan. The corresponding benefits under the reference case gas prices were $303 million and 316 million, respectively. The high coal/balanced case yielded larger cost savings of $1,166 million for the Iowa-Southern Minnesota plan and $1,197 million for the Northwest 345 kV & Dakotas 500 kV plan under high gas prices. Under reference gas prices, the Iowa-Southern Minnesota plan yielded $605 million in cost savings.

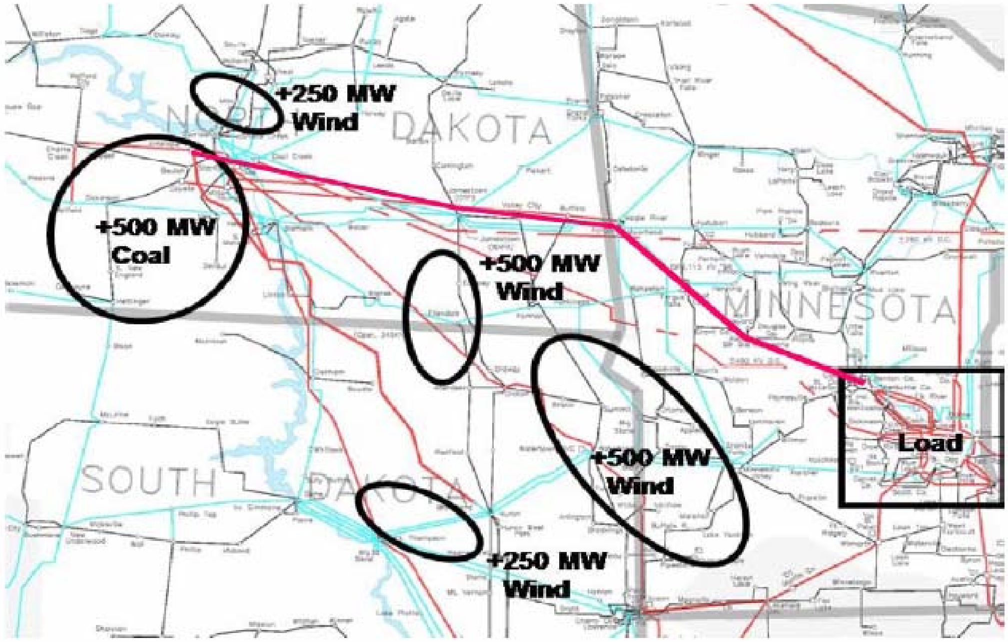
Combined Benefits
Annual Marginal Cost of Wholesale Energy ($M)
MISO and Surrounding

Transmission	High Gas (Min Wind) Reference Case		Balanced		High Wind	
	Ref Gas Prices	High Gas Prices	Ref Gas Prices	High Gas Prices	Ref Gas Prices	High Gas Prices
Base	50,059	57,838				
Iowa-Southern Minnesota			-605	-1,166	-303	-444
Northwest 345 kV & Dakotas 500 kV				-1,197	-316	-478

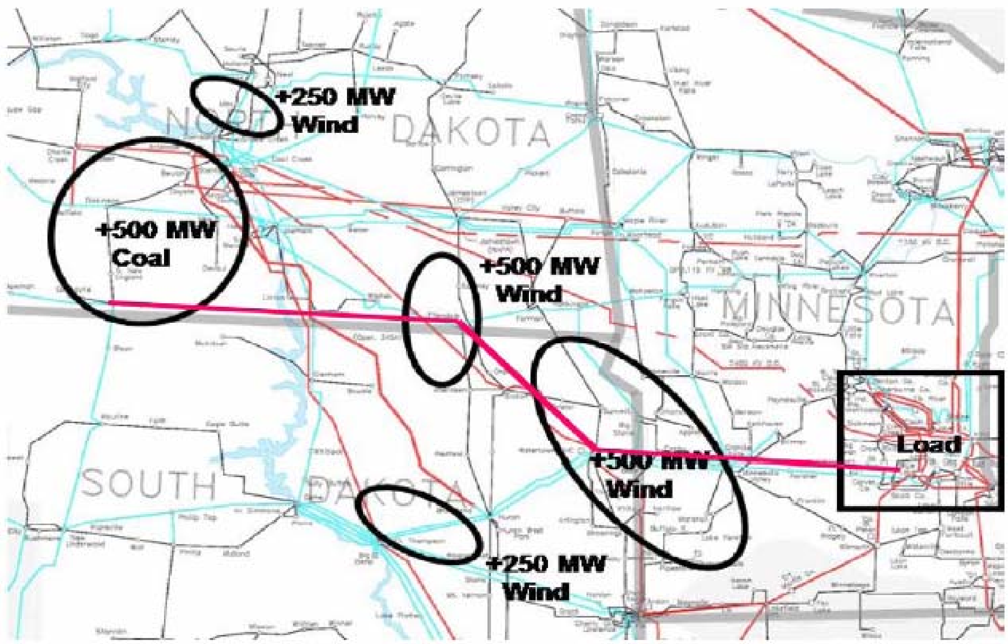
The subsequent Midwest ISO Transmission Expansion Plan 2005 (METP 05)[89] reported on the continuing efforts of the Northwest Area Exploratory Plan to evaluate transmission options linking potential new generation in the Dakotas to Minneapolis. This analysis considered five generation options (wind and coal) and seven transmission options. The generation options included 750 MW of wind in North Dakota, 750 MW of wind in South Dakota, and 500 MW of coal in Belfield, North Dakota. The wind generation assumptions in MTEP 05 are more closely aligned with the Wind Task Force medium case (Scenario 2) which envisioned 500 MW of wind in North Dakota and 750 MW of wind in South Dakota.

The initial round of analysis of the five generation options and the seven transmission options prompted further study of transmission options 1, 2 and 7. Based on insights from the analysis, transmission parameters were modified to generation options 1 and 3. For MTEP05, three transmission options (Options 1, 2 and 2K) were identified for further study as shown below.

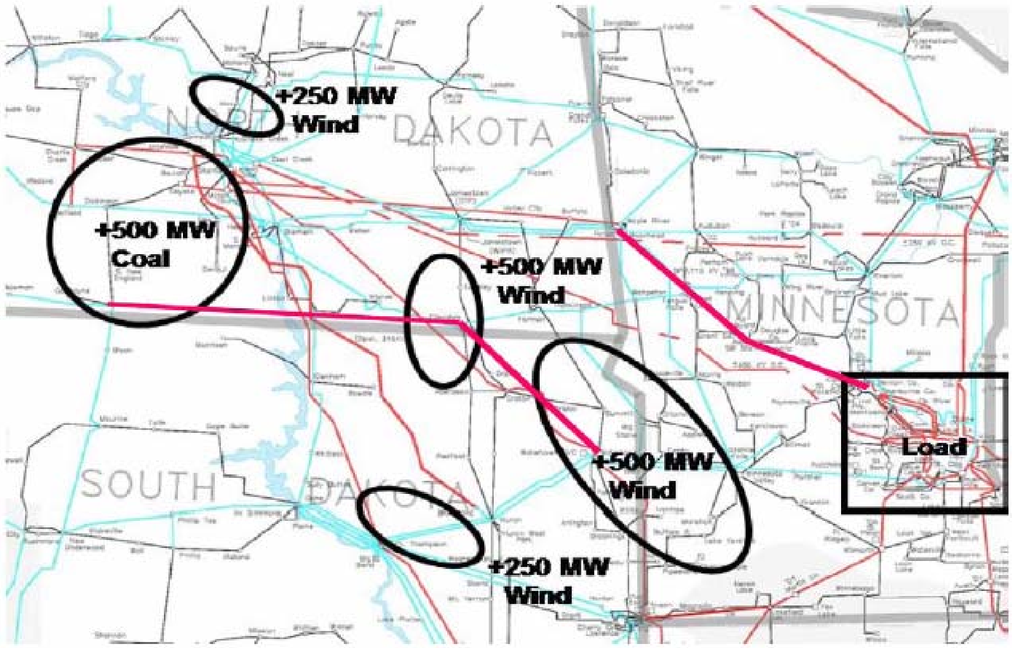
[89] Midwest ISO Transmission Expansion Plan 2005 (METP 05), June 2005 (http://www.midwestiso.org/plan_inter/expansion.shtml).



NW Transmission Option 1



NW Transmission Option 2



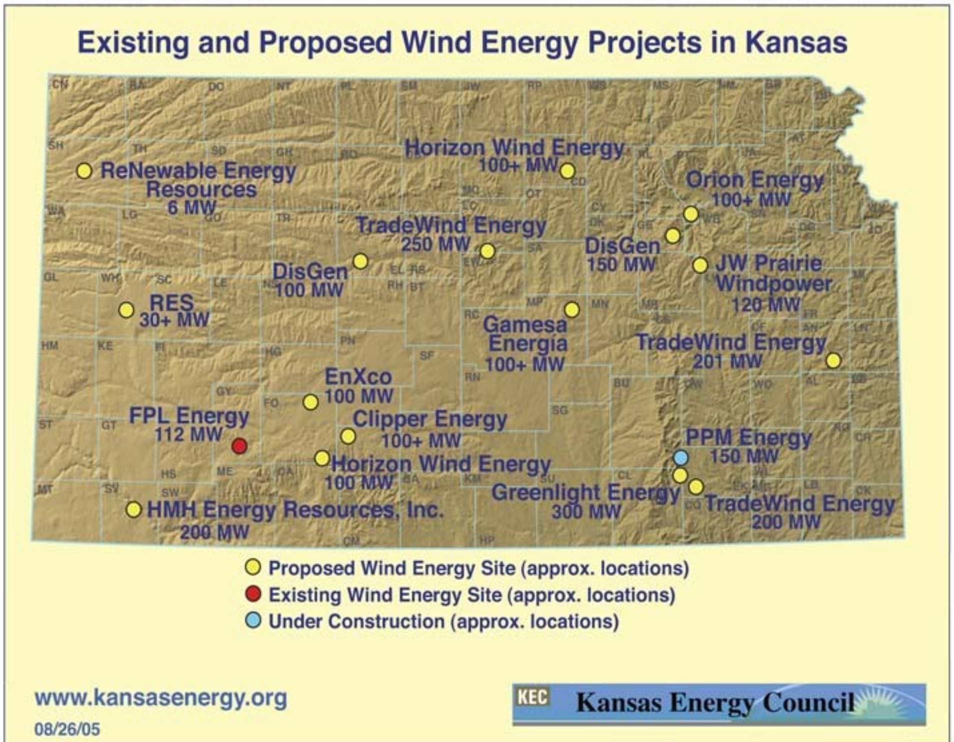
NW Transmission Option 2k

SPP Transmission Expansion

The Southwest Power Pool (SPP) covers one entire WGA state, Kansas, and portions of two other WGA states, New Mexico and Texas. Significant wind resources exist in western Kansas, eastern New Mexico, and western Texas. SPP has been studying transmission expansion opportunities in this region known as the Kansas/Panhandle Expansion Plan.[90]

The Wind Task Force projected that Kansas wind energy development would be 2,500 MW by 2015 based an analysis by the Kansas Energy Council. See the map below showing the Kansas wind projects. The high case scenario of wind energy development in the states of New Mexico and Texas are 6,000 MW and 8,640 MW, respectively. The SPP region overlaps a portion of Texas wind resources and the eastern part of New Mexico's wind resources. The Biomass Task Force identified biomass resources in this region but assumes the biomass energy would be delivered without additional new transmission. The Geothermal and Solar Task Forces did not identify significant geothermal or solar resources in Kansas or the relevant regions in New Mexico or Texas. The Coal Task Force has not produced a recommendation for future coal generation.

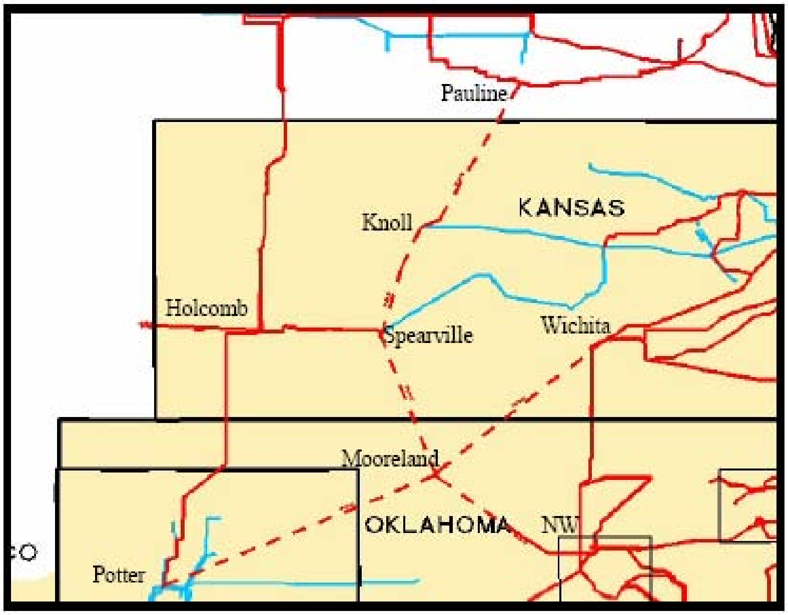
[90] The SPP website provides information the Kansas/Panhandle Expansion Plan at http://www.spp.org/Objects/Engineer.cfm.



Wind Task Force Assumptions of Wind Energy in Kansas

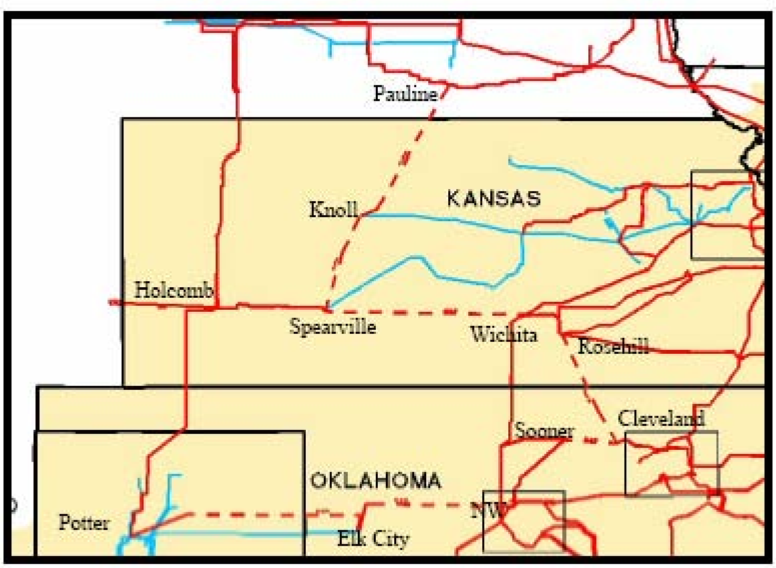
SPP's Kansas/Panhandle Expansion Plan examined multiple transmission scenarios to export 2,500 MW of wind energy and 600 MW of coal energy out of the SPP system. The June 2005 version of the Kansas/Panhandle Expansion Plan specified four wind generation sites: Holcomb, KS (500 MW); Potter, TX (1000 MW); Nichols, TX (500 MW); and Tolk, TX (500 MW). SPP's assumption of 500 MW of wind generation in Kansas and 2000 MW of wind generation in Texas does not completely line up with the CDEAC-Wind Task Force assumption of 2500 MW in Kansas.

The SPP's Kansas/Panhandle Expansion Plan focused on two transmission options, Plan A and Plan B. As shown below, Plan A consists two new 345 kV lines that would cross Mooreland, OK and extend north to Pauline, NE, northeast to Wichita, KS, southeast to Northwest, OK, and southwest to Potter, TX.



Plan A – Kansas Panhandle Expansion Plan

Plan B would construct three segments of new 345 kV lines including: Pauline, NE to Spearville, KS and Wichita, KS; a second segment from Rose Hill, KS, Cleveland, OK, and Sooner, OK; and a third segment from Potter, TX to Elk City, OK and Northwest, OK.



Plan B – Kansas Panhandle Expansion Plan

The projected cost of the 345 kV upgrades under Plan A was $419 million compared to Plan B's $410 million. When common upgrades and additional upgrades are factored into a total cost comparison, Plan A has a lower total cost at $458.7 million relative to Plan B at $477 million. SPP's Phase I analysis recommended Plan A over Plan B based on a transfer analysis and installed transmission costs. The Phase II analysis utilized wind profiles and compared production cost savings under different seasons. The annual production cost savings assuming new wind development and Sand Sage coal plant for Plan A equaled about $72 million and for Plan B just over $60 million. Over ten years, Plan A provided savings of $490.7 million that exceeded the project cost of $458.7 million. SPP's Phase II analysis recommended Plan A over Plan B.

SPP continues to analyze new variations of the Kansas/Panhandle Expansion Plan. Staff is currently analyzing transmission assuming a greater amount of wind (3,146 MW) and revised locations.[91]

In addition to SPP's studies, MISO examined transmission expansion in the SPP region as part of an MTEP 2003 scenario (SPP 345 kV Expansion). This scenario examined the impact of adding several 345 kV lines in western and central Kansas, Oklahoma, and part of southwestern Nebraska.[92]

SPP 345 kV Expansion – MTEP03

[91] Telephone conversation with Bruce Walkup of SPP, October 20, 2005. (501-614-3200).
[92] Midwest ISO Transmission Expansion Plan 2003, p. 242-247.

The MISO analysis of the SPP 345 kV Expansion showed that the transmission additions relieved 5 constraint bottlenecks identified in the MISO system. The SPP scenario direct costs were estimated to be $530 million and about $106 million in annualized carrying costs. The analysis of the benefits from reduced costs of wholesale energy was greater than the annual cost of transmission to resolve the constraints under both the high gas price and reference gas price scenarios.

ERCOT Transmission Expansion

The Energy Reliability Council of Texas (ERCOT) region covers 75% of the Texas land area and 85% of the load. The Texas Panhandle region is connected to SPP. The El Paso area is part of the Western Electricity Coordinating Council (WECC). Two sections of East Texas are in the Southeastern Electric Reliability Council (SERC) and SPP.

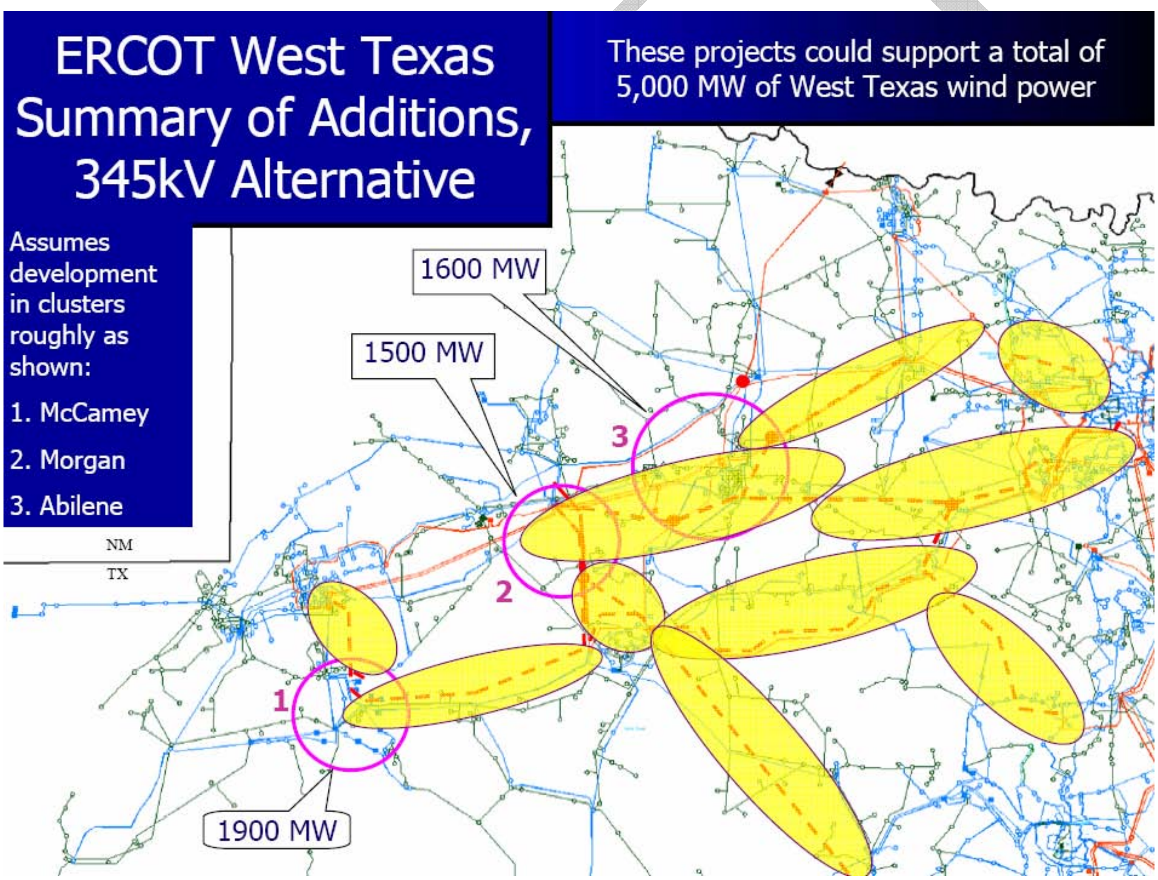
The Wind Task Force relied on joint industry and ERCOT White Paper[93] to forecast Texas of wind energy generation in 2015. The Wind Task Force attributed 3,641 MW of new wind energy under Scenario 2 and 8,641 MW of new wind energy under Scenario 3. The table below presents the regional contributions for both scenarios. Of the total Scenario 2 Texas wind generation, 3,325 MW is located in ERCOT and 316 MW is located in SPP. For the Scenario 3 Texas wind generation, 4,925 MW is in ERCOT and 3,600 MW falls in SPP.

	Region	Existing Wind Generation 12/2004	CDEAC-Wind TF Scenario 2 (TX 5,000 MW Proposal) Wind Energy MW Added	CDEAC-Wind TF Scenario 3 (TX 10,000 MW Proposal) Wind Energy MW Added	Total Wind Energy
ERCOT	McCamey	750	750	1,250	2,000
	Morgan/Sweetwater	250	1,100	1,400	1,650
	Abilene	200	1,175	1,475	1,675
	South Coast	0	300	800	800
	Subtotal	1,200	3,325	4,925	6,125
SPP	Panhandle (Amarillo)	84	236	2,236	2,320
	South Plains (Lubbock)	0	80	1,080	1,080
	Vernon	0	0	200	200
	Subtotal	84	316	3,516	3,600
WECC	Far West (Guadalupe)	75	0	200	275
	Total Texas	1,359	3,641	8,641	10,000

93 Transmission Issues Associated with Renewable Energy in Texas, Informal White Paper for the Texas Legislature, 2005, March 28, 2005.
http://www.ercot.com/AboutERCOT/TexasRenewableWhitePaper2005/RenewablesWhitePaper.htm

The Biomass Task Force identified biomass resources in this region but assumes the biomass energy would be delivered without additional new transmission. The Geothermal did not identify significant geothermal Texas. The Solar Task Force forecasts __ MW of solar energy in Texas. The Coal Task Force has not produced a recommendation for future coal generation.

The Texas White Paper presented transmission options to accommodate the increase in renewable energy corresponding to the Wind Task Force Scenarios 2 and 3. Under Scenario 2, a preliminary ERCOT study examined the option of a series of 345 kV upgrades in West Texas to accommodate 3,641 MW of new West Texas wind energy for a total of 5,000 MW in three principle areas (McCamey, Sweetwater, and Abilene). See the map below. Additional upgrades would be required to bring the West Texas wind energy to the load center in Dallas-Fort Worth, and to integrate wind power to the ERCOT system. ERCOT estimated cost for this transmission expansion at $1.0 billion.



ERCOT estimates that an additional 100 to 300 MW of new wind energy could be injected into three separate areas along the Texas Gulf Coast for a total of 300 to 900 MW of wind energy without requiring significant new transmission facilities.

The CDEAC Scenario 3 wind development level of 8,641 MW additional wind energy would require additional transmission expansion in ERCOT and the SPP. One option contemplated in a preliminary analysis is a series of 345 kV upgrades in ERCOT and a new 345 kV loop in SPP that would connect Vernon, Amarillo, Lubbock, and Big Spring. A new DC tie or switchable facilities would connect ERCOT to the Panhandle region of SPP. The estimated cost of transmission of this first option ranges from $1.7 to 2.1 billion. A second transmission option entails a 765 kV line along with 345 kV additions. The cost of the 765kV/345kV option ranges from $2.5 to 3.0 billion. The table below summarizes the transmission options for both Scenario 2 and Scenario 3 wind development in Texas.

Wind Scenario	Transmission Option	Transmission Costs
CDEAC Wind TF-Scenario 2 (Incremental 3,641 MW)	345 kV option to support 5,000 MW of total wind	$1.0 billion
CDEAC Wind TF-Scenario 3 (Incremental 8,641 MW)	345 kV option to support 10,000 MW of total wind. Includes 345 kV loop Vernon-Amarillo-Lubbock-Big Spring plus necessary upgrades to connect ERCOT grid to the Panhandle (SPP) via DC Ties or switchable facilities.	$1.7 – 2.1 billion
CDEAC Wind TF-Scenario 3 (Incremental 8,641 MW)	765 kV/345 kV option to support 10,000 MW	$2.5 – 3.0 billion

By comparison, the SPP Kansas/Panhandle Expansion Plan (discussed above) evaluated transmission additions to support 2,500 MW of wind in the SPP region, and 2000 MW came from the Texas Panhandle region. The Plan A version of this project was estimated to cost $458.7 million.