# Chapter 4 - Cost Allocation and Cost Recovery Issues

## A. Introduction

RMATS has identified and recommended potential upgrades and expansions to the transmission system in nine western states.[1] The economic analysis shows these projects could produce lower costs to the extent the lower production costs are translated into lower wholesale prices throughout the Western Interconnection. Phase II of RMATS will focus on potential mechanisms to make the RMATS recommendations financially viable by addressing cost allocation and cost recovery.

This chapter is organized in six sections:

- A problem statement explaining the regulatory uncertainty that surrounds transmission and other factors that have affected transmission investment;
- A brief summary of previous recommendations to the Western Governors and by the Federal Energy Regulatory Commission (FERC);
- An overview of the importance of existing regulatory practices associated with transmission cost allocation and cost recovery;
- Proposed transmission expansion cost allocation principles;
- Specific recommendations for how to proceed in Phase II; and
- Project-by-project suggestions on a starting point to consider participation and financing of the transmission expansions.

The recommendations herein represent the broad consensus of the RMATS participants, and are respectfully offered to the sponsoring governors, state and federal regulators and potential project participants for their consideration and implementation.

## B. Problem Statement

Investment in new transmission infrastructure in the West has lagged behind the growth in both demand and new generation. There have been very few new bulk power transmission infrastructure additions in the western interconnection in over a decade. With low gas prices throughout the 1990s, most additional generation has been gas-fired, located close to load, requiring little additional transmission capacity. New transmission capacity that has been added has been devoted primarily to maintaining local reliability, particularly in the Pacific Northwest and Arizona, or accommodating the gas-fired generation interconnections in various locations.

Regulatory uncertainty, arising from questions about recovering the cost of transmission investments and the impact of FERC's push toward open access to the transmission system with the issuance of Order Nos. 888 and 889 beginning in 1996, is a major reason for the lack of recent transmission investment. These and subsequent FERC orders have begun the process of decoupling what has historically been an economic and operational link between investment in new generation and new transmission infrastructure. This decoupling allowed other generators to compete to serve load of the host utility. Prior to the advent of transmission open access, entities responsible for serving native loads planned generation and transmission investments in tandem with the expectation that such investments, since they were devoted to serving native load

[1] Three incremental upgrades included in Recommendation 1 could involve Colorado, Idaho, Montana, Utah and Wyoming. Long-term recommendations for exports from the RMATS region are also presented for projects that could involve states outside the RMATS region, including California, Oregon, Nevada and Washington.

customers, would provide the least cost means to serve customers and be recovered through the retail rates paid by those customers. Under open access, transmission owners are required, subject to contractual rights and capacity availability, to make excess capacity on their transmission systems available to third party users. Revenues from these services reduce the rates paid by native load customers.

Historically, state regulators, who have exclusive authority to set retail rates, have allowed 100% of the cost of transmission investments for state-jurisdictional transmission owners to be included in the cost of service for native load customers. Any revenue that is generated through the use of the system by third parties has typically been credited against the revenues required from the native load customers.

State jurisdictional transmission owners who invest in new transmission capacity at the request of a third party, per FERC Order No. 888, may experience additional risk of cost recovery to the extent that revenues from the third party are insufficient to cover the cost of the requested capacity addition. Depending on the rate treatment adopted, the transmission owners, shareholders or customers bear this risk. This risk is a barrier to investment in transmission.

Federal policy also encourages formation of RTOs in order to remedy undue discrimination in the use of transmission facilities. With an RTO, transmission owners could voluntarily turn over operation of their transmission to an entity that would have the ability to determine the beneficiaries of new infrastructure development and assist in identifying and implementing appropriate cost recovery approaches. For the utilities that join an RTO, much of the uncertainty regarding the rights and cost recovery associated with new transmission investment could be eliminated.

As a result of these factors and developments, the transmission grid is increasingly regional in nature, with a corresponding increase in the interdependency of transmission owners in the region. This interdependency adds to the uncertainty regarding the rights to control and operate the assets of transmission owners, creating an additional barrier to new transmission investment. This uncertainty will persist in the West until state and federal policies on RTO formation are reconciled.

Power on the Western Interconnection does not necessarily flow over the path on which it is scheduled but instead flows according to the laws of physics and follows the path of least resistance. These unscheduled power flows, or "loop flows," as they are often called, are difficult to predict. Power flows also change over time as loads and resources across the system evolve. These factors introduce uncertainty about the amount of physical capacity that will be available at any given time and can affect virtually every transmission path in the Western Interconnection

The increasingly regional nature of the grid resulting from open access adds uncertainty in the decisions that transmission investors must make. This is especially true for transmission investments that would provide widespread benefits to consumers in multiple state jurisdictions. It is this uncertainty that the recommendations in this chapter are meant to address. Establishing regulatory clarity on assigning and recovering costs will help to enable the financing of projects by regulated utilities and merchant transmission entities. The regulatory uncertainty associated with new transmission investments, including specific examples and potential strategies to mitigate that uncertainty, are described in greater detail in the remaining sections of this chapter.

Another impediment to transmission investment is the traditional regulatory practice of accounting accruals for capital investments as AFUDC[2] during the time when construction work is in progress. These funds are accounted for, with interest, and only included in regulated rates after a plant investment is in service and a prudency determination has been made. This means that for investments that have long construction time-frames, such as transmission expansions and coal plants, there is a significant cash flow and no allowed rate of return on investment for multiple years. In contrast, investing in natural gas-fired plants located in proximity to loads can be put into service relatively quickly and with lower capital requirements, minimizing both cash flow requirements and the period of time these outlays do not produce a rate of return.

The lack of transmission investment to enable consumers access to lower cost coal and wind resources is an increasing concern because without transmission investment the region will, by default, become increasingly reliant on natural gas-fired resources located close to load, with the attendant exposure to high and volatile natural gas prices.

### C. Past Recommendations to Western Governors and from FERC

Transmission investment (capital and operating) costs can be directly assigned to market participants, such as generation developers or loads – this is referred to as *participant funding*. It can also be recovered through retail electric rates across the broader system (or a subset of the system), which is commonly referred to as *rolled-in* ratemaking.

A report to the Western Governors in February 2002[3] discussed the need for regulatory certainty to finance transmission expansion, and described the pros and cons of the participant funding and rolled-in models in some detail. While recognizing these two cost responsibility philosophies are not necessarily mutually exclusive, the report did not explore any hybrid possibilities.

Among the recommendations in the report to the Governors in 2002 was the following:

> *3.b. The Governors should urge FERC and state Public Utility Commissions (PUCs) to form joint State/FERC panels to adopt appropriate mechanisms that will enable cost recovery of transmission investments made before the RTO structures are fully implemented. Working in conjunction with SSG-WI, 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 risks and the need for financing incentives.*[4]

RMATS Phase I has defined specific potential transmission expansions. Phase II will be an approach similar to the process recommended to the Western Governors, focusing on specific projects that have demonstrated value in the RMATS study.

In the April 28, 2003 White Paper on Wholesale Power Market Platform, FERC stated:

> *We will look to the RTO or ISO and the regional state committee to determine the appropriate regional approach for allocating the costs of new transmission. Regions may differ on the extent to which they want to rely on participant funded expansions; this difference need not create "seams" with neighboring regions. Because this issue is such an important one in stimulating appropriate investment by both existing and new*

[2] Allowance for Funds Used During Construction
[3] *Financing Electricity Transmission Expansion in the West*, February 2002.
[4] Ibid, at p. 4.

*transmission companies, we will allow an RTO or ISO to implement such policies once there is a regional planning process through which an independent entity performs all necessary facilities studies and determines cost responsibility for the required transmission upgrades.*

While the RMATS region does not have an RTO or an ISO, FERC may consider projects and the allocation of costs and rights recommended by the RMATS process because it is a regional planning process that is independent of any one utility. It seems that FERC would seriously consider any cost allocation and pricing proposal that would have acceptance by state regulators, utilities, generators, and customer advocates within the RMATS region.

Regional solutions for transmission system expansion and pricing are encouraged by FERC. Further, state regulators look favorably upon regional solutions to the extent that regional solutions are shown to be cost effective for their constituents.

**D. The Importance of State and Federal Ratemaking Practices**

Presently state (retail) and federal (wholesale) ratemaking consists of two independent processes. Retail rates and regulation fall under the exclusive domain of the state regulatory commissions and transmission and wholesale power rates are under the federal jurisdiction. This bifurcated regulatory system can and will have a profound effect on the ability to obtain financing and cost recovery on any new transmission, and must be understood and addressed in order to facilitate the RMATS transmission recommendations.

FERC consists of up to five commissioners who are appointed by the President of the United States. FERC has absolute jurisdiction over wholesale electric rates, both transmission and wholesale sales. The state regulatory commissions in Colorado, Idaho, Utah and Wyoming consist of three commissioners appointed by their respective Governors. In Montana there are five elected commissioners. The state commissions have exclusive jurisdiction over bundled retail rates. A component of rates paid by retail customers is transmission-related costs that can face both state and FERC jurisdiction.

Electric utilities fall into one of two broad categories: jurisdictional and non-jurisdictional. Jurisdictional utilities are typically the investor-owned utilities, such as PacifiCorp, Idaho Power Company, Northwestern Energy (NWE) and Xcel Energy, which are subject to both state and FERC regulation. Merchant power and transmission companies fall under FERC jurisdiction. Federal Power Marketing Administrations, such as the Bonneville Power Administration (BPA) and the Western Area Power Administration (WAPA) and most public utility districts, municipalities, cooperatives and rural electrification associations are non-jurisdictional to FERC and state commissions. However, many non-jurisdictional entities abide by FERC rules, either voluntarily or under reciprocity provisions.

Transmission expansions constructed by jurisdictional companies that have no retail load are regulated exclusively by FERC. Revenues for these entities are dependent entirely on wholesale users of its transmission system.

This section does not focus on issues associated with construction and expansion of transmission by non-jurisdictional utilities. Non-jurisdictional utilities have the ability to design their rates in more flexible ways. However, even projects that are sponsored by non-jurisdictional utilities may involve commercial arrangements with state jurisdictional utilities and be subject to state regulatory review. In some cases, state regulatory review is required for non-jurisdictional utilities.

**State Regulation**

State regulators have jurisdiction over retail rates and tariffs and are usually involved in four major areas: planning, construction, siting and cost recovery.

The planning process typically involves an Integrated Resources Plan (IRP)[5]. An IRP typically involves a stakeholder process that includes a stakeholders process and a plan that identifies how a particular utility will serve future load growth. If utilities are to be involved in a transmission expansion identified by RMATS, an important step will likely be consideration of the expansion as an element of each utility's resource planning process.

State regulators become involved in construction through the issuance of a Certificate of Public Convenience and Necessity (CPCN). The purpose of a CPCN is to ensure that the construction of the project is required and will not impair the electric consumers of the state now or in the future. CPCNs, if required, must be sought by jurisdictional and, in some cases, non-jurisdictional entities.

Siting of new transmission facilities is also regulated and may require municipal, county, state, federal and Tribal Nation approvals. Please refer to Chapter 5 for more discussion on siting.

Cost recovery is accomplished through rate cases that are submitted by jurisdictional utilities to the commissions in each state. Generally, each state has its own process independent of the other states. Multi-state jurisdictional utilities must submit rate cases in each state. These state rate cases occur after an investment becomes operational, with typically five to seven years of siting and construction outlays in the case of a large transmission investment.

Jurisdictional utilities are likely to be involved in the future development of any new transmission recommended by RMATS. Therefore, RMATS has included state regulators in the process and has attempted to develop information in the screening studies to facilitate state regulatory review of the recommendations.

**FERC Regulation**

FERC has exclusive jurisdiction over wholesale transactions, both rates and tariffs, for transmission facilities. FERC has developed a seven-factor test to differentiate transmission facilities from local distribution facilities. In the case of transmission, FERC is committed to wholesale competition as the best means to achieving the lowest possible wholesale power prices. To this end, FERC has been on a steady course to encourage the independent operation of the transmission system through RTOs. FERC encourages RTOs as a means to ensure open access and to promote regional planning and elimination of transmission rate pancaking (paying multiple wheeling charges for a path). FERC also encourages the formation of RTOs as a means to enable an independent entity to implement the outcome of regional infrastructure planning, both in terms of siting and cost recovery.

FERC has encouraged performance-based regulation proposals and indicated that it would consider other innovative transmission pricing proposals such as a higher return on equity than previously allowed, levelized rates, accelerated depreciation and incremental pricing for new transmission investments in order to stimulate new transmission construction.

[5] Integrated Resource Plans are also commonly referred to as Least Cost Plans. For purposes here, IRPs and LCPs refer to the same planning activity.

FERC has expressed interest in, and support of, the RMATS process. FERC staff has participated in the study to ensure that RMATS recommendations to facilitate new transmission development are consistent with, and based in part on, FERC's policies.

**Cost of Service Methodology**

While there are many ways to set rates, the most common and widely used method is Cost of Service (COS) ratemaking. It is utilized by FERC and almost every state jurisdiction. The basic equation for COS ratemaking is:

(Allowed Rate of Return * Capital Rate Base) + Expenses + Taxes + Depreciation = COS.

There are often adjustments made to the inputs of this equation to reflect the effect of specific events such as mergers, historical disallowances, weather variations, etc. The COS is then allocated over billing determinates that typically include energy consumption and peak demand.

The RMATS recommendations for cost allocation and cost recovery are based on COS concepts. See Appendix G for several simplified examples of how the cost of service methodology could apply to a transmission expansion investment, depending on the circumstances.

During the course development of the RMATS recommendations, attention was given to the dual state and federal regulatory responsibilities for cost allocation and cost recovery. Recommendations for Phase II activities to facilitate new transmission development were based, in part, on the principles discussed below.

## E. Proposed Transmission Expansion Allocation Principles

RMATS recommends the state PUCs work together to employ a common approach to allocating transmission expansion costs across companies and states. The existing institutional and regulatory structure is the starting point, and the driving principle should be that costs be allocated on bases proportional to benefits and transmission rights received ("beneficiary pays"). To begin implementing this principle, the RMATS study produced estimates of the potential benefits by region. The goal is to allocate the costs of facilities based on the nature and purpose of the investment and the level of use by various customers. This approach is generally consistent with current practice. However, federal and state regulators and potential project participants may also want to look to new ways of cost allocation and regulatory assurance, if necessary to make projects viable.

Cost allocations should:

- Reflect clear, transparent and verifiable criteria and methods;
- Encourage proper investment (protect reliability and support wholesale markets insofar as this lowers retail rates);
- Ensure timely recovery of all prudently incurred costs;
- Enable nondiscriminatory, fair and equitable pricing;
- Take into account the multiple measurable benefits of a facility over its full life; and
- Minimize process burden and avoid contention while ensuring due process.

These principles could be implemented by an operational RTO, however this institution is lacking in the RMATS region. In the absence of an RTO, implementation of these principles will require strong analytics and a clear process for identifying cost responsibility and assigning rights, and coordination among project participants, their respective states, FERC, and stakeholders. A broad consensus among PUCs, project participants and other stakeholders, and strong political leadership will be critically important.

The RMATS study and recommendations focus on economic upgrades.[6] As such, the options for participation focus on market participants funding projects using a beneficiary-pays allocation mechanism.

Market participants should be given first opportunity to finance the projects identified by RMATS. Participant funding refers to payment for transmission capital requirements by entities that request, require or voluntarily undertake to pay for new transmission. Participants who provide capital for network upgrades would receive a return of the capital, with interest over a defined period of years, as a credit against the participant's transmission rate, once it begins to take service.[7] Facilities that would always be funded directly by participants include generator interconnection-related facilities and merchant transmission facilities.

To the degree that participant funding is not forthcoming for reliability or regionally economic investments where benefits are widely diffuse, a regional rolled in method for allocating costs to customers could apply. Under this allocation method, the cost of transmission facilities (net of any participant funding) could be assigned to utilities by state based on their proportional share of loads. Such costs would then be recovered through the companies' wholesale and retail rates, through the existing regulatory process.

In the case of some facilities, a targeted or "zonal" rolled-in method could be used if the reliability or economic benefits are more localized. These include radials to load connection points, portions of looped switch gear, lower voltage upgrades and higher voltage transmission when it is shown that only one entity benefits.

## F. Recommendations for Phase II Actions

As the Western U.S. tries to meet its growing loads in an era of rising natural gas prices, Rocky Mountain coal and wind resources will look increasingly attractive. The RMATS recommendations are economic transmission expansions that could support increased reliance on coal and wind resources. Phase II of the RMATS process will address barriers to financing and cost recovery that may hinder timely development of these transmission projects when and if they are needed to serve customer needs.

The Rocky Mountain grid is operated by multiple control areas according to reliability criteria developed by the Western Electricity Coordinating Council and the North American Electric Reliability Council. At present, there is no RMATS regional pooling arrangement, independent

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[6] Transmission upgrades can be categorized as follows:

- *Reliability upgrades* are defined as transmission investment necessary to provide acceptable stability response, short circuit capacity and system voltage levels. Reliability upgrades also include facilities required to provide adequate thermal capability and local voltage levels that will probably not otherwise be achieved.
- *Economic upgrades* are defined as transmission investment that provides net economic benefits to the region, as determined in RMATS. These include facilities that do more than interconnect a generator, and that are designed to reduce bulk power costs in the Rocky Mountain states and, in the case of export paths, in West Coast and Southwest markets.

[7] Credits are provided for in FERC's generation interconnection rule, Order No. 2003.

system operator or manager, and there is no single transmission tariff. Further, there is no regional decision-making body in place to govern cost allocation decisions that span multiple states and companies.

A regional RTO could develop over time to remedy the balkanized nature of western transmission operation and planning. For example, Grid West is continuing to pursue agreement with regional participants on a phased approach to implementation. However, for the next several years and for purposes of this RMATS process, we must assume no operating RTO exists and will examine alternative means to cost allocation and recovery of specific, desirable projects.[8]

RMATS provides the following specific recommendations on how to proceed. The recommendations are submitted to the region's Governors, regulators, potential project participants and others for their consideration and implementation.

**Pursue Financial Participation and Regulatory Recovery of Recommended Transmission Upgrades on a Project-by-Project Basis**

A Phase II focus on developing transmission in the RMATS region should explore options for cost allocations on a project-by-project basis. Phase II should examine creative approaches within the status quo regulatory and institutional framework to move individual projects forward.

Ratemaking treatment at the state and federal level must be consistent to allow the investors in the upgrades to recover their full cost of capital and a reasonable return on this capital, without undue regulatory risk and within a reasonable period of time. To the extent that Phase II is successful in recommending an allocation of the costs and rights to transmission upgrades across the various stakeholders, it can contribute to a basis for consistent regulatory treatment.

**Transmission Recommendation 1**

The RMATS transmission projects in Recommendation 1 consist of three discrete expansions: 1) the Montana System Upgrade; 2) the Bridger Expansion Project; and 3) the Wyoming to Colorado Project. As presented in Chapter 3, the distribution of economic gains and losses associated with these three projects fall predominantly on the Rocky Mountain region. Taken together, the consumer benefits in reduced load cost and the incremental generator gross margins are estimated to be in a range from $290 million annually to over $1.1 billion per year for the 2013 test year (see Figure 3-9). This makes a compelling case for entities in the Rocky Mountain region to work together and develop a cost allocation and cost recovery solution within the region, as a means for capturing this benefit.

Because these estimates are based on a market structure model of perfect competition, and are based on the assumption that all prices are set by locational marginal pricing, in order to identify likely project participants, we must infer from this information how these cost savings would be distributed to customers given today's market structure.

**Transmission Recommendation 2**

Recommendation 2 consists of five different projects which have been paired together to make four options. The primary purpose of all four options is to construct new transmission lines that would

[8] RMATS solutions to cost allocation and cost recovery could be implemented by Grid-West, if and when it becomes operational.

be able to export an additional 3,900 MW out of the RMATS region to meet needs in the West, particularly California.

These projects could allow Load Serving Entities (LSEs) outside of the RMATS region to diversify fuels, lower generation costs and facilitate the reduction of market power by enabling new generators to develop projects that compete with incumbents in their service territories.

In contrast to Recommendation 1, this recommendation is focused on exporting power into higher-cost markets on the west coast from the Rocky Mountain region. Not surprisingly, consumer benefits are shown to be significant throughout the Western Interconnection. In most areas outside the Rockies, the consumer benefits are approximately offset by reductions in generator gross margins. This may or may not impact owners of the displaced generating resources depending on duration of existing contracts and rate treatment of those plants. The reduction in load cost for California consumers is noteworthy, at over $600 million per year, and appears to outweigh the potential loss of generator gross margin within the State of about $300 million (see Figure 3-12).

The consumer and generator benefits for the RMATS region also increases, compared to Recommendation 1, to within a range of $926 million to over $1.7 billion per year. These results suggest that a thrust of RMATS Phase II should be to coordinate Recommendation 2 with California's transmission planning institutions, as well as with the upcoming cycle of west-wide transmission planning done by SSG-WI. The solution to allocating and recovering costs under Recommendation 2 should include a region broader than the RMATS region, in recognition of the widespread beneficiaries.

**Phase II Initial Step**

As an initial step under Phase II, RMATS recommends, for each of the recommended transmission expansion projects, that the Governors of the states where the line would be sited convene a meeting of their public utility commissioners and CEOs of the entities that will likely benefit from an expansion project for the purpose of: (a) presenting the RMATS findings; (b) urging the beneficiaries to sponsor the project in Phase II; (c) setting in place a process for siting, allocating and recovering project costs and (d) conducting transmission technical studies. Governors should also consider inviting Governors and PUCs of other states outside the geographic scope of the transmission projects that would also benefit.

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- For the Montana System Upgrade Project, RMATS recommends that the Governor of Montana convene a meeting of the CEOs of Northwestern Energy, the Bonneville Power Administration, the Montana Public Service Commission, coal and wind power plant developers in Montana, merchant transmission developers and other potential project sponsors and participants.

- For the Bridger Expansion Project, RMATS recommends that the Governors of Idaho, Utah and Wyoming convene a meeting of the CEOs of Idaho Power, PacifiCorp, the Utah Associated Municipal Power Systems, the Utah Municipal Power Authority, the Wyoming Infrastructure Authority, coal and wind power plant developers in Wyoming, the Idaho Public Utilities Commission, the Utah and Wyoming Public Service Commissions, merchant transmission developers and other potential project sponsors and participants.

- For the Wyoming to Colorado Transmission Project, RMATS recommends that the Governors of Colorado and Wyoming convene a meeting of the CEOs of Xcel Energy, PacifiCorp, Black Hills Power, Basin Electric Power Cooperative, Tri-State G&T, theWestern Area Power Administration, City of Colorado Springs, the Platt River Power Authority, the Missouri Basin Power Project, the Colorado Public Utilities Commission, the Wyoming Public Service Commission, and the Wyoming Infrastructure Authority, coal and wind power plant developers in Wyoming and Colorado, merchant transmission developers, and other potential project sponsors and participants.

- For the export project options included in Recommendation 2, RMATS recommends that, depending on the option under consideration, the Governors of the affected states convene a meeting of the interested utilities, regulatory agencies and others.

- For example, if an option enhancing exports to California were being considered, we recommend that the Governors of Utah, Idaho and California convene a meeting including PacifiCorp, the Utah Association of Municipal Power Systems, California investor-owned and municipal utilities, the California ISO, the Utah Public Service Commission and the California Public Utility Commission. The Wyoming Infrastructure Authority should also be involved in meetings associated with Recommendation 1 projects..

**<u>Pursue Improvements in Regulatory Institutions to Enhance Ability for Resolution of Transmission Cost Recovery Issues</u>**

In addition to exploring financial participation and regulatory recovery for the projects in Recommendations 1 and 2, RMATS recommends improvements in existing regulatory institutions. Five specific enhancements are summarized here.

**Develop Multi-State Pricing Principles**

RMATS recommends that the Rocky Mountain states, 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 RMATS 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.

A binding agreement among the commissions should be explored, as well as voluntary approaches to application of pricing principles. RMATS recommends that the pricing principles recently approved by FERC for the Northeast region serve as the model for pricing principles developed by RMATS.

RMATS also recommends exploring means to increase regulatory certainty, including, but not limited to: forms of pre-approval; higher rates of return on transmission investments; and quicker rate-basing of transmission investments,. In Phase II, a joint stakeholder and regulatory group could be formed to provide a forum for exploring these options.[9]

### Institutionalize RMATS Regional Planning

Transmission planning capability will need to be available to support Phase II activities, including the application of pricing principles to specific projects, evaluating other benefits of transmission projects, such as increased reliability, fuel diversity, and providing input to federal and state regulatory processes.

The RMATS planning function should continue to be coordinated with other sub-regional plans through the broader west-wide planning performed by SSG-WI. Further, if Grid-West becomes operational, the RTO could assume the transmission planning function, and RMATS regional planning could devolve.

### Coordinate Regional Transmission Planning with LSE Resource Plans

To improve regional transmission planning efforts and LSE resource plans, RMATS recommends the (1) the RMATS transmission recommendations be considered in the resource plans of LSEs in the Rocky Mountain region and in the review of such plans by the regulatory commissions in Colorado, Idaho, Montana, Utah and Wyoming; and (2) future RMATS transmission planning build on the most recent resource plans and resource acquisition actions of LSEs in the Rocky Mountain region.

RMATS broke new ground in regional transmission planning by explicitly incorporating the resource plans of Idaho Power Company, PacifiCorp. and Xcel into the analysis of transmission Alternative 1. The development of a "quasi" integrated resource plan for the region (Alternative 2) highlighted potential investments in new generation and transmission that could lower costs compared to existing LSE resource plans. Closer coordination of regional transmission planning with LSE resource plans can improve the quality of both efforts and should be encourages.

### Engage the Wyoming Infrastructure Authority

In the 2004 legislative session, Wyoming enacted a law[10] creating the Wyoming Infrastructure Authority (WIA). The WIA has the authority to own, operate and maintain high-voltage interstate transmission facilities. Within the state of Wyoming, the WIA also has condemnation power to facilitate transmission expansion planning and siting.

The WIA became effective July 1, 2004 and is governed by a five-member board, appointed by the Wyoming governor. To begin its work, the Wyoming legislature appropriated operating funding.

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[9] This approach may not work for the RMATS Recommendation 2, because these export projects implicate a broader geographic footprint than the RMATS region. However, if the pricing principles lead to successful transmission expansions in the Rocky Mountain region, by example this success could lead to broader application of these principles throughout the West. This could be done voluntarily among states, through an organization such as CREPC or as an element of RTO formation.

[10] The engrossed bill, Senate File 52, is available at http://legisweb.state.wy.us

This funding is deemed a loan and the WIA will ultimately be obligated to repay the loan with interest.

The WIA has the authority to issue revenue bonds to raise capital to build transmission infrastructure it would own. 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.

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. These opportunities should be vigorously examined in RMATS Phase II, and should involve the WIA board.

### Pursue More Efficient Ways to Use, Operate and Expand the Transmission System

The RMATS region is a large subset of the geographic footprint that is the western interconnected system. Grid West, which is under development, would be an RTO covering Washington, Oregon, Nevada, Idaho, Utah, British Columbia and most of Montana and Wyoming. Stakeholders are exploring this option through the Regional Representatives Group and other forums.

A fully operational RTO such as Grid West would be designed to independently operate transmission over this large region, streamline transmission access and pricing, consolidate control areas, and address congestion, planning and expansion of the system. An RTO would have a common tariff and be an institutional means for implementing transmission cost allocation and recovery. It is conceivable that a future RTO in the RMATS region could adopt an approach of transmission expansion costs not unlike the ISO New England model that was recently approved by FERC.

RMATS recommends that Governors and regulators consider the formation of an RTO with features appropriate to the region, including independence and cost-effectiveness. RMATS encourages ongoing efforts to explore formation of Grid West, including its collaborative approach with regional regulators and stakeholders.

RMATS also recommends that the region not wait for Grid West or other RTOs to form and become operational, as the sole means of addressing transmission expansion opportunities in the Rocky Mountain region. To do so risks perpetuating the status quo should the institutional changes not materialize. Such a delay may translate into a lost opportunity to realize consumer benefits from added infrastructure that RMATS has shown to potentially be over $1 billion per year. Accordingly, RMATS participants strongly believe the region collectively should move forward on these recommendations.

### Strengthen Regional Coordination

At the direction of Western Governors, CREPC[11] has explored the value of an enhanced regional electricity function among the states and provinces in the Western Interconnection. CREPC examined the value of an enhanced regional electricity function in five areas: reliability; resource adequacy, market monitoring, transmission planning and expansion, and transmission permitting. In March 2004, CREPC found that at this time, the West does not need the formality of an interstate compact, nor is there a need to transfer any state-level authority to a regional body. However, there is an urgent need to enhance the regional electricity function of states and provinces. This requires additional resources for states and provinces to act regionally to: (1) ensure quality analysis of the adequacy of resources to meet demand; (2) enable coordination among the states and FERC on monitoring Western electricity markets; and (3) enable active state participation to advance regional transmission planning and expansion and ensure Governors' policy objectives are addressed. CREPC found that to be successful, any enhanced regional electricity functions need the imprimatur of Western Governors. CREPC also found that:

- Continued progress in pro-active transmission planning is contingent on the voluntary efforts of a few companies and regular engagement of Governors; pro-active planning has not become routine.
- The WGA Transmission Permitting Protocol appears adequate for coordinating permitting reviews of proposed interstate transmission lines, but has not yet been tested because no new interstate transmission line has been proposed since the Protocol was signed in 2002.
- If the pending Federal energy legislation is enacted to establish mandatory reliability standards and grant FERC the power to pre-empt state electric transmission siting laws, then additional action is needed.
    - Governors would need to create an interconnection-wide regional reliability advisory body; and
    - Additional resources would be needed to participate in the federal government's identification and designation of "national interest" transmission lines where state permitting authority would be preempted.

In June 2004, Western Governors accepted CREPC's recommendations, directed that options be developed to finance an enhanced regional electricity function, and requested stakeholder input on the recommendations.

## G. Ownership and Financing Considerations

The transmission expansions in Recommendation 1 include three discrete projects. To a degree, ownership and financing options can be anticipated because the incremental projects add transmission capacity to existing corridors, implicating specific entities with ownership or rights to the existing transmission system. RMATS participants offer the following as a starting point for Phase II discussions among these parties and others. This presentation is in no way intended to

[11] CREPC refers to the Committee on Regional Electric Power Cooperation, an organization that includes the regulatory, energy and facility siting agencies in 12 Western states and two Canadian provinces in the Western Interconnection.

imply that the utilities or other market participants have made any commitments regarding participation or financing of these transmission projects. Nor is this starting point intended to preclude other options that may be taken up by parties in Phase II discussions.

**Montana System Upgrade Project**

The Montana System Upgrade Project would increase the capacity of the existing 500 kV transmission system by an estimated 500 MW. This project consists of increasing series compensation, adding a new transformer and constructing two new substations. This increased capacity would allow the export of new wind and coal resources from Montana to the Pacific Northwest.

Potential customers for this project are LSEs in the Pacific Northwest who could benefit from access to low-cost coal and wind resources. Possible investors are the current transmission owners (Avista, Portland General Electric, PacifiCorp, Puget Sound Energy and Northwestern Energy), BPA, and perhaps independent transmission developers. The ownership structure will likely be joint ownership for the section between Colstrip and Townsend (Ringling) and BPA ownership for the remaining section. The operators of this project are likely to be Northwestern Energy and BPA.

The financial viability of this project will depend on its ability to attract long-term firm commitments from creditworthy counterparties for transmission service. If these counterparties are state-regulated LSEs, then regulatory approval of the transmission agreements may be required to satisfy potential investors in the project. The current bankruptcy of Northwestern should not have an adverse impact on this project assuming that Northwestern emerges from bankruptcy prior to the construction of the project.

While creative ownership and financial structures could be designed for this project, classical balance sheet financing by the current transmission owners who choose to participate is anticipated. Because all current owners, other than BPA, are FERC jurisdictional, favorable treatment by FERC for those entities and favorable treatment by BPA will be necessary. Even though the most likely recovery of investment will be through FERC rates and tariffs, favorable state regulatory treatment for jurisdictional utilities involved will also be required.

If, as expected, the additional capacity facilitates development of new wind and coal resources in eastern Montana by new participants, it may help mitigate generation market power not only in the Pacific Northwest but also in Montana. However, if the incumbent generation owner in the area acquires the additional transmission rights and no new entrants build wind or coal generation, the effect of the additional transmission capacity may be to increase the incumbents' generation market power.

Next steps will require a core group of the market participants noted above to either independently or jointly perform a detailed study of the project. The investor-owned utilities would also need to evaluate the project in the context of their resource plans. Merchant generators will need to secure buyers for their output. Then, the market participants will require approvals for construction as well as regulatory approval of rates. Viability of this project will require that commercial participants be identified and regulatory approval or acknowledgment of IRPs from state commissions.

**Bridger Expansion Project**

The Bridger Expansion Project would increase the ability to move power from Wyoming to Utah and Idaho by 1,350 MW by adding new transmission lines between the Minors substation in Wyoming to the Ben Lomond substation in Utah and between the Bridger plant in Wyoming to the Midpoint substation in Idaho.

The primary purpose of this expansion would be to increase the transfer of low-cost coal and wind resources from Wyoming. This project could increase fuel diversity and reduce generation costs. Although conceptually the project is likely to provide greater reliability, such effects have not been modeled or otherwise quantified. Conceptually, the project may also mitigate generation market power but again this effect has not been studied.

We can identify the current market participants that operate in the relevant area as likely candidates for interest in this project. PacifiCorp and Idaho Power are candidates because they have generators, transmission facilities and service obligations that interconnect with the project, and they are located in the area where significant cost savings are expected to occur. Other market participants that either have generators, transmission facilities or service obligations that interconnect with the project include the merchant coal and wind resource developers in Wyoming, UAMPS, UMPA,[12] Sierra Pacific, Raft River Rural Electric Cooperative and possibly Northwestern Energy. Additionally, the WIA may be interested to the extent this project fits their criteria for funding.

Ownership structures for this project could be joint, individual or segmented depending on which is most efficient. To the extent that the current transmission owners finance this project, it is likely to be balance sheet financed. If the WIA finances a portion of this project that portion is likely to be 100% debt with bond repayment assured by the parties who execute contracts for service with the WIA. A turn-key contract with the WIA may also be a viable alternative to consider.

Next steps will require a core group of the market participants noted above to either independently or jointly perform a detailed study of the project. Utilities that are required to perform IRPs would also need to evaluate the project in that context in order to decide upon their participation in the project. Merchant generators will need to secure buyers for their output. Then, the project participants will require approvals for construction as well as regulatory approval of rates. Viability of this project will require that commercial participants be identified, the WIA's role, if any, be clarified through bond counsel, and regulatory approval or acknowledgment of IRPs from state commissions.

**Wyoming to Colorado Transmission Project**

The Wyoming to Colorado Transmission Project would increase the ability to move power from Wyoming to Colorado by 750 MW by adding a new 345 kV transmission line between the Powder River Basin and just northeast of Denver and adding series compensation. The primary purpose of this expansion would be to allow the delivery of low-cost coal and wind resources from Wyoming to Colorado.

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[12] UAMPS and UMPA refer to the Utah Associated Municipal Power Systems and the Utah Municipal Power Agency, respectively.

This project could allow the LSEs in the Colorado Front Range to diversify fuels, lower generation costs, and facilitate the reduction of generation market power by allowing new suppliers to develop projects that compete with incumbents.

The most likely customers for this expansion are the utilities that serve loads in the Front Range of Colorado, such as Xcel, municipal and cooperative utilities served by WAPA, Tri-State and Basin Electric and coal and wind developers. Black Hills Corporation may also have an interest, in light of its pending acquisition of Cheyenne Light and Power from Xcel.

Current owners (WAPA, Tri-State, Xcel, Basin and Wyoming Municipal Power Agency) of the transmission system are likely to be the owners and equity participants in this project. However, this project could also be financed and owned by independent transmission developers or the WIA. Ownership structures for this project could be joint, individual or segmented depending on which is most efficient. To the extent that the current owners finance this project, it is anticipated to be balance sheet financed. If the WIA finances a portion of this project, that portion is likely to be 100% debt with bond repayment assured by the parties who execute contracts for service (or a turn-key contract) with the WIA. Portions of the project that may be funded and owned by WAPA will be subject to federal government budgetary processes.

This project will require approvals for construction as well as regulatory approval of rates. This project will require that the WIA's role, if any, be clarified through bond counsel, and regulatory approvals (pre-approvals if possible) from both state commissions and FERC might be desirable.

Next steps will require a core group of the market participants noted above to either independently or jointly perform a detailed study of the project. Utilities that are required to perform IRPs would also need to evaluate the project in that context in order to evaluate their participation in the project. Merchant generators will need to secure buyers for their output. Then, the market participants will require approvals for construction as well as regulatory approval of rates. Viability of this project will require that commercial participants be identified, the WIA's role, if any, be clarified through bond counsel and regulatory approval or acknowledgment of IRPs from state commissions.

## H. Conclusions

RMATS Phase II should examine, on a project-by-project basis, the level of support for advancing the recommended transmission upgrades. This should be done using available means within the existing regulatory and institutional framework. In addition, the RMATS Phase II should develop a memorandum of agreement among the RMATS states and FERC on specific transmission pricing principles. Additional means to institutionalize RMATS regional planning and improve the existing regulatory framework are also recommended.