

Transmission Regulatory Principles Work Group (TREG)

Working Paper

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INTRODUCTION

The purpose of this report is to share the observations and suggestions of the Committee on Regional Electric Power Cooperation (“CREPC”) Transmission Regulatory Principles (“TREG”) work group, formed in Fall 2004 to explore the potential for common state pricing principles for transmission investment. This draft paper represents TREG’s current efforts to assess the nature of the problem and identify potential solutions. We encourage interested parties and stakeholders to review the document and provide comments. TREG is particularly interested in feedback on two points: (1) whether the document has appropriately identified state regulatory considerations to be applied to proposed transmission projects; and if so (2) whether stakeholders have an interest in pursuing the options we discuss at the conclusion of this paper.

Background

An underlying premise of the Rocky Mountain Area Transmission Study” (“RMATS”) Phase I Report directive is that the lack of transmission expansion in the Western Interconnection is partly the result of project developer and investor concern over inadequate cost recovery for long term projects due to state and federal regulatory uncertainty. The RMATS Phase I Report made specific recommendations to the RMATS States¹:

1. To address cost allocation and recovery uncertainties, RMATS recommends that the state public utility commissions and energy agencies in the five states in the RMATS footprint deliver a report to their Governors in six months discussing multi-state transmission expansion cost recovery and pricing principles.
2. RMATS recommends that the regulatory commissions in Colorado, Idaho, Montana, Utah and Wyoming enter into a memorandum of agreement adopting pricing principles, and jointly file the MOA with FERC, requesting its endorsement. These principles would then apply to any applications for transmission cost recovery received by regulatory commissions within the RMATS region, providing a degree of certainty and consistency in regulatory treatment.

In the RMATS report, this cooperative effort is seen as a means to achieve for potential project developers and investors a degree of clarity and consistency regarding the

¹ The Rocky Mountain Area Transmission Study (RMATS) process was formed by an inclusive stakeholder/participant group to achieve, in part, a broad overview of transmission needs in the subregion and to understand them in a coordinated manner to encourage effective transmission planning in the subregion. RMATS states are Colorado, Idaho, Montana, Utah and Wyoming. The CREPC workgroup is formed of participants from these states plus Nevada. For more information on RMATS, its charter is found at: <http://psc.state.wy.us/htdocs/subregional/charter.pdf>

regulatory evaluation of transmission projects, and hence cost recovery, especially for lines that cross multiple states.

The RMATS Report recommended serious consideration of the value of stakeholder cooperation in crafting regional solutions to address regional transmission issues and encouraged the RMATS stakeholders to be proactive in working together, cautioning that the region should not concentrate on regional organizations “as the sole means of addressing transmission expansion opportunities in the Rocky Mountain region. To do so risks perpetuating the status quo” As discussed above, RMATS suggested the RMATS footprint states cooperate in seeking concurrence among themselves on pricing principles that could be brought to the FERC for endorsement (later giving favorable mention to the approach to transmission expansion costs to be used by ISO New England). We understand the importance of taking the initiative now to explore what progress the states might make through cooperative efforts.

Because state regulators do not set wholesale transmission rates and most bundle transmission cost into retail electric service rates, we take the RMATS Report recommendation, for us, to be one of exploring the adoption of common state cost recovery principles.

Review of the New England ISO cost allocation rules and similar Southern Power Pool (“SPP”) cost allocation rules, reveals that an ISO or tight power pool institutional structure is required to directly adopt such rules. Because these structures do not currently exist throughout the west and are not expected in the near term, the workgroup agreed to review the substance of the rules but to concentrate on options that can be implemented using existing institutional structures.

Our work has included examining various existing and proposed transmission projects. We have not reached consensus on whether or not the difficulties faced by transmission developers should be characterized as “barriers” but we are in agreement that the challenges to transmission development become much more complex when the lines become longer, involve more states and serve customers farther away. Therefore, we believe that there is substantial value in setting forth in one place the way regulators in the states view these projects. On a forward looking basis, we propose the use of a regional process to make the task of developers clearer and to ensure that information is shared among the stakeholders early in the process. We do not call on the states to edit their regulatory requirements but to help interested persons better understand the various processes and engage them more constructively.

Scope of Paper

This paper is organized into six sections. Chapter I describes current state and federal regulatory jurisdiction and practice governing transmission investment decisions. Chapter II describes historic and current case studies, illustrating practical issues raised by different types of transmission projects. Chapter III provides cost allocation principles for consideration. Chapter IV is a description in matrix form of different types of

transmission projects, identifying project-types which pose particular investment challenge and identifying the cost allocation principles that would apply to each transmission cost type. Chapter V identifies and describes alternative approaches, mechanisms, and processes for multi-state coordination or agreement consideration. Chapter VI presents a series of questions to state regulators and industry participants on options under consideration. Responses to these questions will assist TREG in formulating its next steps.

CHAPTER I: CURRENT REGULATORY LANDSCAPE

State Transmission Regulation

Jurisdiction and authority

The state regulatory process governing transmission investment includes planning, siting, construction, and cost recovery in retail rates. The following is a general review of state regulatory practices in Colorado, Idaho, Montana, Nevada, Utah and Wyoming.

Planning

Transmission additions are considered in the Integrated Resource Planning (“IRP”) process² in the context of providing long-run, least-cost service to retail customers. Transmission upgrades to better utilize existing generation to meet growing demand may also be considered outside of the IRP process and brought before state public service commissions on a case by case basis. The process for regulatory approval of transmission projects identified in IRPs is similar though not uniform in each state.

The Nevada Public Utilities Commission approves Nevada Power and Sierra Pacific transmission as part of its IRP process. In recent history these have all been intrastate projects but some have interstate benefits. Nevada IRP approval means that the project has been deemed to be in the public interest but the costs associated with the project are subject to review in a rate case following construction.

Idaho and Utah acknowledge IRPs. Regulatory approval of specific transmission projects identified in the IRP occurs later when more is known about the specific generation/transmission project. The basis of the evaluation is the overall cost of the generation/transmission project as compared to other available generation/transmission alternatives. In Idaho, alternatives are identified in a Request for Proposals process.

In Montana, the IRP process applies to traditional utilities that have not restructured; a resource planning and procurement process for long-term default electricity supply applies to restructured utilities. The Montana PSC’s integrated resource planning rules for traditional utilities explicitly require that the opportunity cost of new or existing transmission capacity needed to deliver power from a potential new resource be imputed into the total resource cost. The Montana PSC may comment on whether plans filed by traditional utilities conform to the rules. PSC comments do not bind the commission with respect to future ratemaking decisions. SB 247 requires the Montana PSC to comment on plans filed by restructured utilities. The PSC must identify any concerns it has regarding the utility’s compliance with PSC rules and identify ways to remedy the concerns.

² This process is also known as a least-cost planning process.

Wyoming does not require all utilities to file an IRP; the requirement is imposed on a case-by-case basis as needed.

In addition to the IRP process, Colorado utilities report annually to the Colorado Public Utility Commission on planned transmission projects over the next three years. The Colorado PUC determines which projects are in the ordinary course of business and which will require the utilities to seek a Certificate of Public Convenience and Necessity (“CPCN”) to begin construction.

Transmission planning may also be coordinated with utility distribution planning processes. Additional planning efforts occur in the voluntary, though not formally recognized, RMATS planning process.

Construction

For state jurisdictional utilities, i.e., investor-owned utilities like PacifiCorp, and also for rural electric cooperatives in Wyoming, construction of new transmission facilities located in that state requires receipt, after hearing, of a CPCN. Extension of existing facilities may not require a CPCN but in some states may require notice if the cost is over a specified amount.

In Utah, Interlocal Entities (i.e., UAMPS) or out-of-state public agencies must also obtain a CPCN, after hearing, for new facilities located in Utah; however, if the new facilities provide additional project capacity or provide additional project capacity within the corridor of an existing transmission line, the facilities are exempt from the CPCN requirement. In Wyoming, the certification requirement applies only to public utilities and entities which will become public utilities after the construction of the line.

Applicants for a CPCN in Utah or Idaho must show that public convenience and necessity does or will require such construction and in addition that such construction will in no way impair the public convenience and necessity of electrical consumers of that state at the present time or in the future. In Wyoming, issuance of a CPCN means that the present or future public convenience and necessity require or will require such construction. Under the general public interest standard the facility must be necessary for the utility to continue to provide safe, adequate and reliable service in the public interest. In its orders, Wyoming expressly reserves the determination of rate making treatment for a future appropriate proceeding – most often a general rate case. This reservation applies to certification and securities cases.

Construction of transmission facilities in Nevada requires a Utility Environmental Protection Act (“UEPA”) permit. Local Governments are exempt from the UEPA but all other entities must obtain an UEPA for utility facilities (including transmission 200 kV or greater) built in Nevada. In order to obtain the UEPA, an entity must prove that it has applied for and obtained all local, state and federal environmental and siting permits and an entity must demonstrate that there is a “need” for the project. The determination of “need” includes findings relative to the reliability benefits of the project to consumers in

Nevada, the need outweighing any environmental impact, and promoting the public interest (see NRS 704.890 at <http://leg.state.nv.us/NRS/> for a complete statement of the law).

Siting

In Idaho and Utah, siting of new transmission facilities is not under state public service commission jurisdiction but rather is considered and approved by county zoning and planning commissions and then by county commissions, regardless of whether the facilities are proposed by utilities or merchant developers.

Siting in Wyoming is not centralized in one governmental entity. Because county siting requirements vary, compliance issues should be addressed with the concerned county planning offices. Issues will include county utility right-of-way regulations, subdivision regulations and land use plans affecting zoned areas. Lines not exceeding 500 KV are exempt from the Wyoming Industrial Siting Act but must comply with informational filing requirements. Lines proposed to run across or along roads and highways in Wyoming, including interstates, must first be approved by the Wyoming Department of Transportation. A storm water permit from the Wyoming Department of Environmental Quality is required during construction if the surface disturbance exceeds one contiguous acre (and is therefore not applicable to most transmission projects).

Transmission rights-of-way in Wyoming may be acquired by condemnation by cities, towns, utilities and others, including the Wyoming Infrastructure Authority. If a CPCN is required for the project, the condemnation proceeding cannot go forward until the certificate has been issued by the PSC.

The Montana PSC does not have siting authority for either generation or transmission. Siting authority rests primarily in the Department of Environmental Quality and the Board of Environmental Review. In Montana the Major Facility Siting Act (“MFSA”) was the bedrock, comprehensive review process used in Colstrip 3 & 4 and the two associated 500 kV transmission lines across Montana into the northwest. The five owners of Colstrip 3 & 4 had prorata ownership shares in the transmission project. BPA constructed the western portion. Since then, several legislative sessions narrowed the scope of the MFSA. For example, generation facilities were completely removed from the scope of the act and transmission facilities were limited to major lines (greater than 230 kW?). Siting Act rules were recently revised and restructured but authority continues to reside at the Department of Environmental Quality.

Transmission Cost Recovery through Retail Rates

All transmission costs, both capital and ongoing, are considered for recovery by state public service commissions in retail rate proceedings. Prudent transmission costs are recovered from customers in the price they pay for service. To date, we are unaware of any disallowance associated with transmission investment or expenses in the RMATS

region. We are aware of one instance in which additional wholesale wheeling revenues were imputed.³

Criteria for determining cost recovery (This section addresses, to some extent, a review of the decision-making, risk allocation component of transmission investment)

Criteria used to determine transmission investment cost recovery varies.⁴ Generally, evaluation of transmission investment is tied closely with prudence review of generation plant additions.

If a state has an IRP process, adherence to its results may form the basis for prudence determination. For example, PacifiCorp engages in a system-wide⁵ planning process to determine the optimal investments needed to minimize long-run total cost to operate its integrated utility system. With respect to new generation and transmission facilities, most PacifiCorp states agree the basis for least cost evaluation is system wide, rather than state specific analysis.⁶ This is because PacifiCorp operates its system based on minimizing total utility system cost rather than minimizing individual state utility service. Joint-use transmission costs are therefore allocated among states rather than directly assigned to the state in which the facility is located. For distribution and demand-side investments, the PacifiCorp states agree that PacifiCorp will evaluate opportunities based on system cost, through the IRP process; however, state specific programs are developed for, approved by and costs directly assigned to the state in which the investment occurs.

Competitive bidding results may additionally inform transmission investment prudence determination. Indeed, specific alternatives may not be known until competing proposals are solicited and evaluated.

Although most PacifiCorp states support IRP and common allocation factors, costs recovered in each state result from state specific rate proceedings. Thus, evidence and expert opinion regarding prudence can vary in each state and therefore differences in the amount of costs included in rates can still take place.

Wyoming case law allows the Public Service Commission to make a determination of the proportion of cost responsibility to be borne by rate payers before the construction is undertaken. It is not mandatory and no such determinations have been made to date. (Does case law identify criteria for determining the proportion of cost responsibility borne by rate payers?)

³ WAPA wheeling contract with PacifiCorp.

⁴ The following is a general discussion and placeholder for evaluation criteria. Further refinement of criteria employed should be possible with information gained from our review of actual cases in each state.

⁵ PacifiCorp serves retail customers in six states and wholesale customers throughout the WECC from its generating resources located in nine states and wholesale purchase contracts and transmission rights located throughout the WECC.

⁶ Wyoming, Utah, Oregon and Idaho Commissions have adopted the Multi-state Process (MSP) “revised protocol” allocation factors. These four states comprise about 90% of PacifiCorp’s retail energy load. The Washington Commission has deferred decision on allocation method for its next rate proceeding; and California may also be looking at it in a rate proceeding.

The Montana PSC has ratemaking authority over utility investments. The substantive legal standard for inclusion in rate base is "actually used and useful." Montana Power's share in Colstrip 3 was ultimately included in rate base along with the associated transmission. Colstrip 4 was not included in rate base and has operated in the wholesale market along with associated transmission--mostly under long term contracts (to LADWP and later Duke). As a normal practice, transmission upgrades to satisfy reliability and retail demand are presented in rate cases under traditional used and useful standards. There has been very little criticism or challenge to such transmission upgrades.

The one unique aspect of Nevada's transmission allocation and rate determination process is that Nevada allows customers with a load of 1 MB or larger to contract for their own power. The law requires these customers to procure at least half of their resources from a new source in Nevada (i.e., to either build their own source or to contract with another entity that is building new generation). Transmission service to allow these "exiting customers" to import part of their resources presents some issues which may not be experienced in other intermountain west states.

There are currently no specific criteria established by the Idaho PSC to evaluate transmission upgrades; each project is considered on a case by case basis. IRP transmission cost will be evaluated for inclusion in rates based on the generation/transmission cost as compared to other available generation/transmission alternatives.

Rate (Pricing) Treatment (This section also address risk allocation)

Here are three ways through which prudent transmission cost can be apportioned to customers: Bundled retail cost of service; unbundled transmission service; unbundled retail and wholesale transmission service. A brief description of each follows.

Cost Recovery through Bundled Retail Cost of Service

In this approach, transmission cost of service and wholesale wheeling revenues⁷ are combined with other cost of service functions, i.e., generation, distribution and overheads, etc., to form a single retail rate. No distinction is made between wholesale transmission cost of service and retail transmission cost of service. This is how PacifiCorp recovers its transmission costs in Utah, Idaho and Wyoming and this is also how transmission cost is recovered in Colorado

For example, PacifiCorp reports to states its financial results and operations using FERC's uniform system of accounts. All transmission net plant investment, expenses and wholesale wheeling revenues are included in PacifiCorp's results of operations and

⁷ Utilities collect revenues from firm and non-firm wholesale transmission customers through contracts or through their Open Access Transmission Tariffs ("OATT"), which are then credited to retail customers, just as wholesale wheeling purchases of transmission service from other utilities through contract or the OATTs are included as expenses in retail rate proceedings.

are apportioned among the state jurisdictions it serves. A utility's purchase of transmission service from another owner's facilities is included as a wheeling expense in its cost-of-service.

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

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

Cost Recovery through Unbundled Transmission Service

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

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

Cost Recovery through Unbundled Retail and Wholesale Transmission Service

This approach also requires separating transmission service cost from non-transmission service cost. A fully-distributed transmission service cost analysis is again performed but now these costs (including only non-firm wholesale wheeling revenues as credits) are allocated to firm retail and wholesale customers based on relative use. Thus, transmission service is further unbundled into retail transmission service and wholesale transmission service. A separate firm retail transmission rate is formed from the retail transmission distributed cost of service study. The retail rate is then multiplied by firm retail use to derive transmission expense and included in retail cost of service. We are unaware of any state in the RMATS footprint that uses this approach.

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

Possibilities for Innovation

Wyoming law gives utilities wide latitude to propose innovative rate making concepts. W.S. § 37-2-121

“The rates may contain provisions for incentives for improvement of the public utility's performance or efficiency, lowering of operating costs, control of expenses or improvement and upgrading or modernization of its services or facilities. Any public utility may apply to the commission for its consent to use innovative, incentive or nontraditional rate making methods. In conducting any investigation and holding any hearing in response thereto, the commission may consider and approve proposals which include any rate, service regulation, rate setting concept, economic development rate, service concept, nondiscriminatory revenue sharing or profit-sharing form of regulation and policy, including policies for the encouragement of the development of public utility infrastructure, services, facilities or plant within the state, which can be shown by substantial evidence to support and be consistent with the public interest.”

The 2005 Wyoming Legislature may consider legislation specifically allowing other AFOR concepts which could be of use in addressing transmission issues.

Federal Transmission Regulation

The Commission's Statutory Authority⁸

The statute governing traditional electric utility rate filings and rate cases at the Commission is the Federal Power Act (FPA). The statutory provisions of the FPA relevant to the rates charged by electric utilities are Sections 201, 205 and 206.

Section 201 establishes the Commission's jurisdiction over the transmission of electric energy and the sale of electric energy at wholesale in interstate commerce. The Commission also has jurisdiction over “all facilities used for such transmission or sale of electric generation,” but no over facilities (1) used for the generation of electric energy, (2) used in local distribution, or (3) for the transmission of electric energy consume wholly by the transmitter. The courts have found that the Commission's jurisdiction over these matters is exclusive. Jurisdiction over retail transactions is left to the states.

FPA Section 205 requires all public utilities file with the Commission all rates and charges for any transmission or sale subject to the jurisdiction of the Commission, and

⁸ Some of the information included in this piece has been obtained from a resource entitled “A Guide to FERC Electric Utility Ratemaking,” written by Michael E. Small of the law firm of Wright and Talisman. Published by Atlantic Information Services, Inc., copyright 1989.

the classifications, practices, and regulations affecting such rates and charges, together with all contracts, which in any manner affect or relate to such rates and charges, together with all contracts which in any manner affect such rates, charges, classifications, and services.

Section 206 of the FPA allows the Commission to modify rates upon its own motion or upon motion or complaint. As a result, the Commission may now change rates and order refunds under Section 206 effective before the date that a final order is issued.

General Electric Rate Filing Procedures

The requirements for the filing of initial rate schedules are embodied in Section 35.12 of the Commission's regulations (18 C.F.R. Part 35). In addition to general information, Section 35.12 requires (1) estimates of the transactions and revenues under the initial rate schedule; (2) an explanation of the basis of the proposed rate or charge; (3) a summary statement of all cost computations; (4) a comparison of the proposed initial rate with other rates of the public utility; (5) a diagram of any facilities which are added or changed; and (6) rate design information.

The Commission's requirements for changes in rates or service are set forth in Section 35.13 of the Commission's regulations. The filing requirements in Section 35.13 are more elaborate than those required in Section 35.12 and have been established in two categories of rate filings: an abbreviated filing and an extensive filing with full cost of service information.

The key issue that a utility needs to address in satisfying these requirements in the Commission's regulations is what test period to use – a historic Period I or a forward-looking Period II. Period I data reflects the most recent twelve months, or the most recent calendar year, for which actual data are available. Period II data is for any period of twelve consecutive months after the end of Period I that begins no earlier than nine months before or no later than three months after the proposed effective date of the rate schedule change.

Cost Recovery Method for Transmission Rates

While the Commission has recently expressed interest in considering alternative transmission pricing structures, historically it has relied on a cost-of-service methodology to allow the public utility to recover its cost of providing service. The foundation for developing transmission rates subject to the jurisdiction of the Commission begins with the FERC Form No. 1 plant accounts, as defined by the Uniform System of Accounts, that identify gross transmission plant in service (FERC Account Nos. 350 through 359). It is the plant costs in these accounts that have been generally determined to include the facilities necessary to perform wholesale transmission service in interstate commerce. Then, with the transmission facilities as the basis for the development of the transmission rate base, one common form of cost-of-service ratemaking that has been prominently used by public utilities: embedded net plant cost-of-service.

The starting point for deriving the cost of transmission service under the net plant method is the application of the following formula:⁹

Transmission Cost of Service = E + D + T + R, where

E = Operating Expenses, including transmission expenses, allocated administrative and general expenses and allocated taxes other than income taxes;

D = Transmission Depreciation Expense;

T = Recovery of income related taxes; and,

R = Overall return on the transmission rate base.

Under the net plant method, the transmission rate base is determined on a depreciated basis. That is, for the Period I or Period II study, gross transmission plant in service is reduced by accumulated depreciation in determining the amount of the transmission facilities to which the overall rate of return will be applied. Then, certain additive and subtractive adjustments (e.g., ADIT adjustments, allocated materials and supplies, etc.) are made to the net transmission plant balance to determine the overall transmission rate base.

Rate Design

After the total jurisdictional annual transmission revenue requirement is developed, the unit charges, or rates, are calculated by dividing the revenue requirement by the appropriate billing determinants. Since transmission service is only demand related, there is no determination of classification of transmission costs into any other class (e.g., energy or demand). Furthermore, with the advent of open access comparable transmission service, there is no need to identify transmission allocation by customer class; all transmission service must be now taken under a pro forma Order No. 888 tariff. Accordingly, in designing the transmission rate, the Commission has utilized the coincident transmission system peak load or CP. In most cases, the Commission has accepted one of two methods: 1CP or 12 CP.¹⁰ The transmission revenue requirement is divided by the CP divisor applicable to the characteristics of the transmission to develop the annual rate for transmission service. It is this rate that all wholesale and unbundled retail transmission customers will pay.

While there are nuances to the cost of service development, including the necessity to credit short-term and non-firm transmission revenues against the annual transmission

⁹ This summary paper will not endeavor into the details of the case precedent surrounding the application of each cost-of-service component.

¹⁰ There have been rate cases involving utilities in the desert southwest region where a 3 or 4 CP rate divisor have been utilized.

revenue requirement, there is no interplay among the development of rates for wholesale transmission service and retail service, including for example, consistent rate development precedent. For example, in developing wholesale transmission service rates, the revenues received by the utility in providing retail service subject to state jurisdiction, are not taken into account in the transmission revenue requirement. There are, however, sometimes different rates for retail ratemaking versus wholesale ratemaking as a result of tax normalization adjustments at one level, while done differently at the other level.

New Approaches to Transmission Pricing

License Plate Rates

The Commission has encouraged the elimination of pancaked rates for transmission service within a regional transmission system and support transition periods for moving to a system of non-pancaked rates. While initially expressing a preference for “postage-stamp” rates (a single, uniform, average rate across all utilities in the regional transmission system), the Commission permitted “license-plate” rates (a rate for service that would vary based on the zone where the power was delivered). Because it avoids rate averaging and allows a utility to maintain its existing rate for deliveries on its system, license plate rates minimizes cost shifts. Under such a rate design, upgrades built on one utility’s system would be paid for by that utility’s load through the load ratio share rate.

Elimination of Inter-RTO Transmission Charges

Recently, as a condition of the former Alliance RTO companies choice of RTO, the Commission required PJM, Midwest ISO, and the former Alliance companies to eliminate transmission charges for service between the RTOs; Midwest Independent Transmission System Operator, et al., 105 FERC ¶ 61,212 (2003), and Ameren Services Company, et al., 105 FERC ¶ 61,216 (2003). A proposal for an alternative revenue recovery mechanism is in progress.

The rate design from these orders is based on the existing rate and revenues for through and out service, but will recover these revenues from customers in the region in proportion to the benefits such customers will receive from the elimination of the unjust and unreasonable rate design, through a non-bypassable surcharge for delivery to load.

In the July, 7, 2003 FERC Staff Paper on Regional Choices for Implementing the Elements of the White Paper, options for the recovery of transmission costs among regional organizations were raised. One option is the negotiation of an export rate that will recover the cost of transmission that is constructed to export to customers in another region but that is not used much for imports to service local customers who may otherwise have to pay for that transmission. Such a proposal may be necessary where there is a notable imbalance between imports and exports. Alternatively, as another option, a reciprocal waiver of access charges gives customers in all the participating

regions a wider range of supply choices, reduces market concentration, and promotes wholesale competition.

In addition, Commission staff facilitated discussion among the New York and New England states' commissions regarding the removal of inter-RTO transmission charges. These discussions led to agreements that call for working toward a mechanism that removes inter-RTO charges with developing programs that will minimize the financial impact by removing these charges.

Merchant Transmission

In several cases beginning with TransEnergie, 91 FERC ¶ 61,230 (2000), the Commission has permitted the costs of merchant transmission facilities to be recovered through negotiated rates, so long as: (1) the merchant project assume full market risk; (2) control of the facilities is given to an ISO or RTO and service is provided under the open access tariff of that ISO or RTO; (3) firm transmission rights are created and traded through the ISO or RTO's OASIS; (4) initial transmission rights must be allocated through a fair, transparent, and non-discriminatory process; (5) the open season results must be posted on the OASIS and filed with the Commission; (6) affiliate concerns are addressed; (7) the merchant facility does not preclude access to essential facilities by competitors; (8) the facilities are subject to market monitoring; (9) energy flows on merchant transmission facilities must be coordinated with and subject to the reliability requirements of the relevant ISO or RTO; and (10) the facilities must not impair pre-existing property rights to use the existing transmission grid. The negotiated rates have been derived from the auction of transmission rights on the merchant facility based on the difference in locational marginal price at either end of the merchant transmission line. Holders of the transmission rights receive the revenues associated with the sale of its transmission rights in the secondary market.

International Transmission Company - Transmission Incentives

Among other things, the Commission permitted International Transmission, the independent transmission company owner of the former Detroit Edison transmission facilities, to invest in new transmission and defer recovery of any amounts of that investment that would exceed its current transmission rate cap until after the rate freeze ended.

TransConnect - Innovative Rate Proposal

The Commission accepted a proposal by TransConnect¹¹, a proposed independent transmission company that was to operate within the footprint of what was then RTO West, to charge certain performance-based rates (See, 100 FERC ¶ 61,297 (2002)). Specifically, the Commission accepted TransConnect's proposal to develop performance

¹¹ The originally proposed TransConnect participants were Avista Corporation, Northwestern Energy, L.L.C., Nevada Power Company, Puget Sound Energy, Portland General Electric, and Sierra Pacific Power Company. Upon later notice, Puget and NorthWestern withdrew from the TransConnect proposal.

benchmarks with its stakeholders, create a revenue sharing mechanism to manage administrative and general costs more efficiently and to further support a proposed indexed adjustment for operation and maintenance expenses.

TransConnect also proposed several concepts for transmission upgrade cost recovery, including direct assignment of costs needed to provide service to a new customer, assignment of transmission rights to the entity which pays for the new facility, and broader allocation of costs where there are system-wide benefits.

American Transmission Company's Incentive Rate Settlement

The Commission accepted a settlement by which ATC would modify its rate formula to: (1) include Construction Work in Progress (CWIP) in the calculation of transmission rates for new transmission investment in lieu of capitalizing an Allowance for Funds Used During Construction (AFUDC), and thereby increasing immediate cash flow for projects; (2) allow current year expensing of pre-certification costs for new transmission investment instead of capitalizing those costs and earning a return; and (3) increase the allowed return on common equity (ROE) from 12.20 percent to 12.38 percent and to return to a 50 percent debt, 50 percent equity, capital structure. ATC requested these modifications as alternative incentives to the ROE basis point incentive adders outlined in the Commission's Proposed Pricing Policy Statement (see below). ATC requested these alternative incentives to facilitate the financing of approximately \$2.3 to \$2.8 billion in new transmission facility construction over the next ten years. ATC states that this new transmission construction is needed to increase reliability on the system, meet load growth, and alleviate congestion.

The Commission required that ATC apply the incentive rate treatment only to projects that are accepted by the Midwest ISO in the Midwest ISO's Transmission Expansion Plan. It also stated that the incentive rates could remain effective for only as long as ATC remains a member of the Midwest ISO.

TRANSLink

Under TRANSLink's proposed rate design, both network and point-to-point transmission service customers would pay a single non-pancaked charge consisting of three components: (1) a highway component; (2) a supply-zone component; and (3) a load-zone component. There are initially six pricing zones reflecting the systems of the three Private Power Participants (Alliant-West, Mid-American, and NSP Companies), two Public Power Participants (NPPD and OPPD), and one Cooperative Power Participant (Corn Belt), in the North Region.

The highway component reflects the cost of the bulk power transmission system facilities deemed to support transfers of energy between zones. TRANSLink proposes to designate all non-radial transmission system facilities operating at voltages greater than 200 kV as highway facilities, and proposes fixed percentages for each zone to allocate the cost of transmission system facilities operating at voltages between 100 kV and 200 kV

to the highway component. No transmission system facilities operating at voltages below 100 kV are deemed to perform a highway function. The cost of existing highway facilities will be reflected in the highway component on a license plate basis during the remainder of the six-year transition period under the Midwest ISO OATT (i.e., through January 31, 2008); reflection of the cost of existing highway facilities in the highway component on a postage stamp basis will be phased in over a four-year period following the transition period. The cost of all new highway facilities that enter service after the effective date will be immediately reflected in the highway component on a postage stamp basis.

The supply-zone component reflects the cost of facilities deemed to support the transfer of power from generators to the highway system. Under the proposal, 50 percent of the cost of transmission system facilities operating at voltages above 100 kV that are not allocated to the highway component will be allocated to the supply-zone component. For any particular transaction, the customer would be assessed the supply-zone component for the zone where its transaction originates.

The load-zone component reflects the cost of facilities deemed to support the transfer of power from the highway system to load. Under the proposal, 50 percent of the cost of transmission system facilities operating at voltages above 100 kV that are not allocated to the highway component and 100 percent of the cost of transmission system facilities operating at voltages less than 100 kV will be allocated to the load-zone component. For any particular transaction, the customer would be assessed the load-zone component for the zone where its transaction terminates.

The Commission found that TRANSLink's proposal addresses certain shortcomings of conventional license plate rate design. It combines the advantages of the license plate and postage stamp rate concepts into one rate design, eliminates rate pancaking, and more closely allocates embedded costs based on the usage of particular facilities than rates that reflect the costs of all transmission facilities on a license plate basis. The postage stamp design for new highway facilities can help mitigate disincentives to new investment to support transactions benefiting load in another pricing zone and may allow a transition to postage stamp rates.

In contrast to the conventional license plate rates, in which a uniform rate applies for all deliveries to load at a particular location, regardless of the location of the resource, TRANSLink's proposed supply-zone component would result in different rates to serve load at a particular location depending on the zone in which the resource is located. The Commission expressed concern regarding the ability of such a pricing proposal to send efficient price signals that will foster decisions for grid expansion, and that the proposal may impact economic decisions. However, the Commission allowed the implementation of the TRANSLink proposal on an initial basis, prior to the commencement of a regional energy market, and further required status reports that would inform the Commission on the impact of the TRANSLink proposal and the continued reasonableness of the proposal once an energy market is established in the region.

The Commission also expressed concern over the proposed highway/zonal rate design because it depends on TRANSLink's functional analysis and designation of facilities as highway or zonal; where designation of facilities as highway or zonal is based on power flow analysis reflecting numerous simplifying assumptions.

Participant Funding

In the Standard Market Design NOPR, the Commission stated that a more precise matching of beneficiaries and cost recovery responsibility would encourage greater regional cooperation to get needed facilities sited and built. The Commission indicated a preference for allowing recovery of the costs of expansion through participant funding, *i.e.*, those who benefit from a particular project (such as a generator building to export power or load building to reduce congestion) pay for it.

The Generator Interconnection proposed rule introduced the idea that participant funding may be an acceptable pricing policy where an independent entity determines: (1) the cost of and responsibility for needed upgrades; (2) congestion price signals to which the customer responds (along with Congestion Revenue Rights); and (3) the assumptions underlying the power flow analysis. However, to get new infrastructure in place as soon as possible, the Commission stated that participant funding could be used for new transmission facilities that are included in a regional planning process which is conducted by an independent entity.

In the absence of independence, the Commission would apply a default pricing policy that would recognize the regional benefits of transmission expansions. Under this default policy, all high voltage network upgrades of 138 kV and above would be rolled-in on a region-wide basis. Since lower voltage, sub-regional transmission needs are less likely to benefit the whole region, the cost of network facilities below 138 kV could be more appropriately allocated to a sub-region (*e.g.*, a single transmission owner or a "license plate" zone) where the expansion facilities will be located. Consistent with the Commission's proposal for interregional transmission service pricing, costs would be allocated to the region that benefits from the expansion, which may not be the same as the region in which the expansion facilities are located. This proposal recognizes that high voltage expansions can have benefits beyond the borders of the local transmitting utility and, therefore, assigns a portion of these costs to more distant beneficiaries.

In the April 28, 2003 White Paper on Wholesale Power Market Platform, the Commission 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 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.

The Commission added that allowing participant funding on the basis of having an independent entity perform transmission planning and related cost allocation is a transitional approach that could be used in anticipation of the RTO or ISO assuming operational control of the regional transmission grid within one year.

Pricing from the Standardization of Generator Interconnection Agreements and Procedures Final Rule

On rehearing of the Generator Interconnection Final Rule, the Commission reaffirmed the pricing policy adopted in Order No. 2003 for the recovery of the costs of Network Upgrades associated with an interconnection (facilities on the Transmission Provider's side of the Point of Interconnection with the Transmission Provider's Transmission System). That is, the Commission's existing pricing policy continues to apply to non-independent Transmission Providers, and an independent Transmission Provider may propose a customized pricing policy to fit its circumstances. The Commission also reaffirmed that all distribution upgrades (upgrades to the Transmission Provider's "distribution" or lower voltage facilities that are subject to an OATT) are to be paid for by the Interconnection Customer (direct assignment).

On rehearing, the Commission clarified that, consistent with the Commission's "higher of" ratemaking policy, a non-independent Transmission Provider continues to have the option to charge the Interconnection Customer the "higher of" an average embedded cost (rolled-in) rate or an incremental cost rate for the network upgrades needed for either Energy Resource Interconnection Service and Network Resource Integration Service. Incremental pricing is not the same as direct assignment.¹²

The Commission also reaffirmed the Order No. 2003 requirement that, unless the Transmission Provider and the Interconnection Customer agree otherwise, the Interconnection Customer must initially fund the cost of any Network Upgrades associated with the interconnection of its Generating Facility to a non-independent Transmission Provider's transmission system and that the Transmission Provider must reimburse the funded amount on a dollar-for-dollar basis with interest. This reimbursement is in the form of credits against the transmission service rates the Interconnection Customer pays for the delivery component of transmission service. However, the Commission required the Transmission Provider to provide credits to the

¹² The Commission explained what it means by "incremental cost" in its 1994 Final Rule concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act (59 Fed. Reg. 55,031 (1994)). In that policy statement, the Commission explained that it has allowed a utility to charge the higher of embedded costs or legitimate and verifiable opportunity costs, but not the sum of the two. The Commission further stated that the opportunity costs, in turn, are capped at the incremental expansion costs.

Interconnection Customer only against transmission service taken with respect to the interconnecting Generating Facility.

In addition, the Commission eliminated the requirement that any Affected System Operator (a system operator that is impacted by the interconnection on a neighboring system) refund an Interconnection Customer's upfront payments for network upgrades built on the affected system as a consequence of the interconnection of the Generating Facility, requiring instead that the affected system to provide credits toward the Interconnection Customer's upfront payment only when transmission service is taken by the Interconnection Customer on the affected system.

Pricing for Transmission Upgrades at the RTOs/ISOs

Order No. 2000 Innovative Rates

In addition to requiring the elimination of pancaked rates and encouraging performance based rates for RTOs, the Commission in Order No. 2000 also encouraged the use of innovative transmission rates. The Commission recognized that transmission pricing reform was needed as a result of the rapid restructuring of the industry, particularly with respect to changes in the ownership and control of transmission assets and changes in the transmission services being provided in competitive power markets. This led the Commission to propose to mitigate various disincentives to transmission owners efficiently operating their systems. The Commission proposed several transmission pricing reform measures:

- (1) a transmission rate moratorium which may include proposals based on formerly bundled retail transmission rates;
- (2) rates of return on equity that are formulary, consider risk premiums and account for demonstrated adjustments in risk, or that do not vary with capital structure;
- (3) accelerated depreciation for new transmission investment;
- (4) transmission rates based on levelized recovery of capital costs; or
- (5) transmission rates that combine elements of incremental cost pricing for new transmission facilities with an embedded cost access fee for existing facilities.

(The original FERC staff paper had a series of pricing proposals at east-coast or Midwest ISO's or tight power pools; I've copied only the western pricing examples.)

West-Specific Pricing Proposals

Nevada Power Company (105 FERC ¶ 61,178 (2003))

Nevada Power proposed to modify its transmission rates to reflect the cost of transmission network upgrades. Specifically, Nevada Power proposed to, among other things, replace its current 4-monthly coincident peak (CP) divisor with a 12-CP divisor

and provide an enhanced ROE of 1-2 percent over its proposed capital structure ROE component of 13.4 percent, pursuant to the Removing Obstacles to Increased Electric Generation and Natural Gas Supply in the Western United States (Removing Obstacles Orders).¹³

The Commission found accepted the requested enhanced ROE of 2 percent or 200 basis points for the transmission facilities that Nevada Power had in service by July 1, 2001 and accepted an enhanced ROE of 1 percent or 100 basis points for those facilities that Nevada Power has identified as in service by November 1, 2002. The Commission determined that the facilities that Nevada Power has constructed is consistent with the objectives of the Removing Obstacles Orders because the relieve congestion in Nevada Power's market, increase the transfer capability of electricity to other markets, enhance regional reliability and connects new merchant generation supply to serve the region.

California's Path 15 Upgrades (99 FERC ¶ 61,306 (2002))

In April 2002, Western Area Power Administration (Western), Trans-Elect, Inc., and Pacific Gas and Electric Company (PG&E) filed a letter agreement with the Commission that set forth rate principles to be followed in the recovery of costs associated with the upgrade of transmission facilities along California's Path 15. The letter agreement provides that Trans-Elect, Western and PG&E each will receive entitlement to the transmission system rights on the Path 15 upgrade.

Trans-Elect requested a 13.5 percent rate of return on equity for its portion of the project, fixed rates at the initial rate level for the first 36 months of service, a 30 year depreciable life for the project and the use of a target 50/50 capital structure. PG&E requested a 10-year depreciable life for its portion of the upgrades, a reasonable industry target capital structure, and a reasonable rate of return on all of the Path 15 project facilities it owns, plus a 200 basis point incentive.

The Commission accepted the rate treatment request by Trans-Elect, and accepted the rate treatment request by PG&E, except for the use of an industry target capital structure.

Recently, the D.C. Circuit upheld FERC pre-approval of incentive rate components (200 basis points on equity and 10-year depreciable life) for PG&E's portion of the Path 15 upgrade project. The Court found that the Commission could properly consider the importance of non-cost factors of a particular project (here, the serious congestion on Path 15) in setting incentives and gave weight to the fact that further review these incentives in the context of a specific rate change will be undertaken before finding that the resulting rates are just and reasonable.

¹³ 95 FERC ¶ 61,225, order on reh'g, 96 FERC ¶ 61,155, order on reh'g, 97 FERC ¶ 61,024 (2001).

CHAPTER II: HISTORICAL EXPERIENCE – TRANSMISSION CASE STUDIES

A. RMATS States Experience

1. Idaho -- Valmy

In the early 1970s, Idaho Power Company was investigating various resource options to meet growing retail load in its service area. The options considered included a wide array of hydroelectric alternatives, geothermal, solar, nuclear and other coal/gas fueled thermal generating projects. At the time, thermal generation with coal as a fuel source was the most economical option and a joint venture with Sierra Pacific Power Company to construct a 500 Mw coal fired plant at Valmy, Nevada was the chosen alternative. The joint venture allowed some economy of scale and manageable construction costs without creating unreasonable generation surplus for either company. The plant cost and generation was to be split 50/50.

The Valmy coal plant was constructed in two phases, a 250 Mw unit (Valmy I) completed in 1981 and another 250 Mw unit (Valmy II) completed in 1984. A Certificate of Public Convenience and Necessity (CPCN) was requested from the Idaho Commission by Idaho Power Company and granted in 1979. The CPCN authorized but did not require construction and did not guarantee cost recovery. The cost of Valmy I was rolled into Idaho Power Company rates in 1982 without significant opposition. Cost recovery for Valmy II was requested in 1985 and partially rejected by the Commission on the grounds that customer load growth used to originally justify the project had not materialized and the second unit was deemed not fully used and useful. The Company began receiving shareholder equity on the second unit in 1990.

Construction of transmission facilities necessary to deliver Valmy generation to Idaho Power load centers began in the 1970s as part of an energy purchase agreement between Sierra Pacific Power Company and Utah Power and Light Company (UPL). Due to transmission constraints, energy delivered from Utah to Nevada was required to move from UPLs system through Idaho Power's system to Sierra's system via the Midpoint to Valmy transmission pathway. The transmission line was also needed for Sierra to take advantage of excess hydro generation available in the northwest including surplus produced by Idaho Power facilities. In order to accommodate the purchase agreement, to take advantage of low cost excess hydro generation and in anticipation of Valmy coal plant construction, Idaho Power and Sierra joined together to construct the 345 kV transmission line from Valmy, Nevada to Midpoint, Idaho, a distance of about 250 miles.

The cost of the transmission line was to be split 50/50, as was the case with the coal plant costs. Actual ownership of the transmission facilities and capital cost originally incurred by each utility to construct the project was based upon facility location within each state. Transmission facilities located in Nevada were the property of Sierra while facilities located in Idaho were the property of Idaho Power. The result was that Sierra constructed,

paid for and owned 150 miles of transmission line (Valmy to Stateline) and Idaho Power constructed, paid for and owned 80 miles of transmission line (Stateline to Midpoint).

To assure a 50/50 split in transmission costs, the agreement between the two companies required that Idaho Power provide annual revenue to Sierra to offset the additional revenue requirement associated with the longer portion of the line located and owned by Sierra in Nevada. The agreement also provided that Sierra own all southbound transmission rights from Midpoint to Valmy and Idaho Power own all northbound rights. The transmission agreement specifying the annual payments and the transfer ownership rights had a term equal to the expected life of the Valmy coal plant.

A document review of Idaho Power's request for a Certificate of Convenience and Necessity, and Idaho Power's two general rate proceedings to incorporate the costs of Valmy I and II, failed to provide any information regarding the transmission line. It seems that although the transmission project was completed in 1980 (a year before completion of Valmy I), it was assumed to be part and parcel of the Valmy generation project and included for cost recovery along with Valmy I. While a portion of Valmy II costs were originally rejected for cost recovery by the Commission, none of the costs associated with Valmy transmission facilities were included in the disallowance.

Summary Observations

- Valmy transmission involved two states (ID, NV) and two participating entities (IPC, Sierra) collaborating on cost sharing.
- This review suggests that the 345 kV Valmy to Midpoint transmission line was constructed for at least three reasons, 1) Sierra access to a firm power purchased from UPL, 2) opportunities for mutually beneficial purchase/sale of excess hydro generation between Sierra and Idaho Power and 3) the ability to construct and share the cost and output of the Valmy coal plant with economies of scale.
- While not explicitly discussed in any of the rate proceedings before the Idaho Commission at the time, cost recovery of Idaho Power's portion of the transmission facilities was closely linked to construction of the Valmy coal plant. The fact that transmission cost recovery was never an issue in any of the cases before the Commission indicates that it was approved as an integral part of the generation project. Although completed prior to completion of the coal plant, it is unlikely that the transmission facilities would have been constructed (at least at current capacity) without construction of the coal resource.
- Based on Idaho Power's most recent Integrated Resource Plan (IRP), the Company's next major transmission project will also be part and parcel of a new generation resource and cost justified on that basis. Similar participation by multiple utilities in future projects will require similar unique timing of need, resource characteristics and geographic siting.

2. Utah – Sigurd

This proceeding began in January 1985 when the U.S. Bureau of Land Management “BLM” filed a written notice to the Utah Public Service Commission “Utah PSC.” BLM stated that two entities, Utah Associated Municipal Power Systems “UAMPS,”¹⁴ and Utah Power and Light Company “UP&L,” sought approval to construct transmission lines across public lands into Washington County (Southern Utah), and requested Utah PSC analysis of the necessity for the lines. The Utah PSC established an investigated docket, Case No. 85-999-08, after finding insufficient information upon which to either answer the BLM inquiry or for a potential regulatory response should either or both parties seek approval for construction of facilities.

In August 1985, UAMPS filed an application creating Case No. 85-2011-01, seeking a Certificate of Public Convenience and Necessity “CPCN” from the Commission authorizing construction of its proposed transmission facilities. UAMPS proposed to build a 230 kV line from the Intermountain Power Plant “IPP” located in Utah to a new substation near the Washington County load center. The Utah PSC consolidated the two cases, 85-999-08 and 85-2011-01, and UP&L responded to the UAMPS case with an affirmative case for its own project. UP&L’s proposed transmission project was linked to the proposed sale by UP&L of 100 MW of Hunter Unit No. 3 to Nevada Power Company, a sale requiring interconnection with Nevada via a new 345 kV line.¹⁵ UP&L proposed to build the line to the Nevada /Utah border from its Sigurd substation. Nevada Power Company would then continue construction of the line from the Utah-Nevada border to a substation in Nevada. UP&L filed an application for Utah PSC approval of its sale to Nevada Power Company of 100 MW of Hunter on Dec. 24, 1985.

UAMPS’ primary argument for construction of its proposed transmission facilities was to ensure transmission access from its resources to its existing and prospective load. It argued it required transmission ownership in order to operate efficiently, i.e., to dispatch its resources economically, enhance opportunities for purchases or sales outside Utah and eliminate its dependence on Utah Power for wheeling (which it argued froze them out of the wholesale market).

The Utah PSC issued its order in the consolidated cases in March 1987. By then, two fundamental changes had occurred. First, natural gas had been approved to enter the southwest Utah market which decreased estimates of electric load growth, one basis for the UAMPS line. Second, the Nevada Public Service Commission had rejected the

¹⁴ UAMPS acts for itself, Deseret Generation and Transmission Cooperative, “DG&T,” and the City of St. George.

¹⁵ Background: Hunter Unit 4, a proposed UP&L coal-fired power plant located in eastern Utah, had by this time been canceled due to lower than expected demand growth. Nevada Power had been interested in owning some of unit 4. When construction of unit 4 was cancelled, UP&L and Nevada Power began negotiating a sale of a portion of Hunter Unit 3. DG&T purchased a portion of Hunter Unit 2 in 1980. UAMPS was then formed for the purpose of purchasing the DG&T portion of Hunter Unit 2. Further, DG&T’s eastern Utah 400 MW coal-fired plant, Bonanza, came on line in 1985 intended for load (oil shale and tar sands development) that failed to materialize. Thus, excess generating capacity existed in eastern Utah.

Hunter Unit 3 sale, the basis for the UP&L line. The Utah PSC applied a rule “that minimizes costs while preserving future options” in delivering its decision. The Commission noted continuing uncertainty regarding the primary bases justifying proposed facilities and approved the least cost option presented to resolve the immediate southwestern Utah reliability concerns but that also provided the greatest flexibility to consider further projects (either UP&L or UAMPS) as uncertainties diminished. The Utah PSC expressly rejected UAMPS’ proposal (and hence its “independence” objective) because it was unjustifiably costly. The Commission made this decision based on its determination that it statutorily must consider the welfare of all ratepayers in the state; that its regulatory perspective is “statewide.”¹⁶ UP&L was ordered to construct the least cost alternative to address the reliability problem in southern Utah.

September 1987, UP&L applied in Docket No. 87-035-26 for a CPCN to build its proposed Sigurd to Nevada Border 345 kV line, this time accompanied with a signed Power Sales Agreement with Nevada Power Company, rather than sale of a portion of the plant. UP&L argued the following retail ratepayer benefits: access to new markets for both firm and non-firm surplus power; increased reliability and stability of Utah Power’s transmission system; wheeling revenues in excess of incremental facility costs. UP&L argued the new line would augment the existing radial line, providing redundancy and greater reliability to southwest Utah. UAMPS/DG&T intervened and requested ownership interest in the line.

The Commission granted UP&L the CPCN in December 1987 and reserved the ownership issue for further adjudication. The Commission ordered that joint-use and ownership issues, as well as the Commission’s jurisdiction over the issues, would be taken up in Phase 2 of the proceeding should parties be unable to come to an agreement.

Meanwhile, in July 1989, UAMPS requested Commission approval of the construction of a 138 kV transmission line from UP&L’s Central substation to St. George City. The Utah PSC granted approval and UAMPS completed construction of that facility.

In the Phase 2 proceeding, UAMPS requested the Commission order UP&L to provide UAMPS with an ownership interest in designated segments of the UP&L backbone transmission system. UP&L offered only contractual rights; an agreement providing such was signed May 7, 1992.

On October 28, 1993, the Utah PSC dismissed UAMPS’ request in Phase 2 of 87-035-26. The Utah PSC states it lacks jurisdiction to order the involuntary sale or purchase of specific property, including transmission facilities. The Utah PSC states that its authority under Sections 54-4-8 and 54-4-13, which have to do with the joint construction, operation or use of facilities by public utilities, does not apply in this case because UAMPS is not a public utility. UAMPS took the issue to the Utah State Supreme Court; their petition was dismissed on Nov. 10, 1994. The Sigurd to Nevada line became operational July, 1990.

¹⁶ Sections 54-1-3 (2) (b), 54-4-2, and 11-13-27, Utah Code Annotated.

Summary Observations

- The Sigurd case involves transmission over two states (UT, NV) and competing projects sponsored by two different utilities (UAMPS, UP&L). This review focused on the issues before the Utah PSC to resolve the competing projects.
- The Utah PSC adopted a least cost evaluation criteria based on lowest cost current construction to meet emergency requirements for the next few years, while leaving open as many future alternatives as possible: “[M]inimize costs while preserving future options.”
 - Perspective of least cost is “interests of all electric consumers in the state of Utah,” rather than one group (jurisdictional utility customers) versus another (non-jurisdictional).
 - Ownership/independence objective of one entity does not trump least cost to ratepayers of the state.
- PSC lacks jurisdiction to order the sale or purchase of the specific property given the circumstances of this particular case, i.e., UAMPS is a non-public utility.

3. Montana – Colstrip

In 1969, Montana Power (MPC) and Puget Sound Power and Light (PSPL) began construction on Colstrip units 1 and 2, 350 MW mine mouth coal fired generating plants in southeastern Montana. Associated with the plants was a 230 kV transmission line built to 500 kV specifications, running from Colstrip to the Broadview substation north of Billings, where they fed power into and through MPC’s existing 230 kV grid for delivery to BPA for transfer to the PSPL service area. MPC and PSPL held equal 50 percent shares in the generating plant and transmission line. The plants went into operation in 1976 and 1977.

In 1971, Montana passed the Utility Siting Act governing construction of power plants and transmission lines, and in 1973 amended the Utility Siting Act to become the Major Facility Siting Act. The Act, administered by the Department of Natural Resources and Conservation, required a Certificate of Environmental Compatibility and Public Need before construction could begin on any generating plant over 50 MW or transmission line over 69 kV (except for lines under 10 miles and under 230 kV). Since Colstrip 1 and 2 were already under construction they were grandfathered from the Siting Act. (Note that the Act has since been revised extensively and currently requires no siting permit at all for generating plants, and requires review of transmission lines 230 kV and higher with a variety of exemptions.)

In 1973, MPC applied to the Montana DNRC for a siting act Certificate to build Colstrip 3 & 4 and associated transmission lines. The plants were 2 700 MW units, fueled by subbituminous coal from an adjacent mine owned by Western Energy, a wholly-owned

subsidiary of MPC. While MPC was the project developer, ownership was to be shared among 5 utilities: MPC would own 30 percent and the remainder shared by Pacific Power & Light (PP&L, now PacifiCorp), Washington Water Power (WWP, now Avista); Portland General Electric (PGE) and PSPL.

The transmission associated with the plant was to be a double circuit 500 kV line, extending from Colstrip to Broadview, and from there to Hot Springs, where they would connect into BPA's Hot Springs substation. The single circuit 230 line serving Colstrip 1 and 2 would be reconducted and have new insulators and would become one circuit of the new line as far as Broadview.

The 1973 Colstrip application triggered a 2 year study period for the DNRC to consult with interested agencies and the public, to investigate the need and impacts and alternatives, to produce draft and final EISs, and to make recommendations to the Board of Natural Resources on whether it could make the findings required by the act and whether to grant the certificate as well as what conditions to place on the certificate.

In its analysis of need and alternatives the Department concluded that MPC could not demonstrate that the plant represented "minimum environmental impact" among alternatives, as required by the Act, because the alternative of shipping coal by rail to a load center site for the plant appeared to be a cheaper alternative with no greater overall impact. Accordingly the Department recommended in 1975 that the Board of Natural Resources turn down the permit. The Department had studied, but made no recommendation on the route of the proposed transmission line. This may have been a strategic decision in the interests of not weakening their proposed rejection of the plant.

There followed a series of contentious hearings (in which the Public Service Commission recommended turning down the plant) and contentious deliberations. Ultimately, in 1976 the Board granted the permit for the plant with numerous conditions, and it granted the permit for the transmission lines as proposed. A series of appeals and lawsuits followed with the only major change in the outcome being the designation of the Northern Cheyenne Reservation as a Class I airshed and consequent requirement for 90 percent sulfur removal via scrubbers, and construction began on the plants.

The transmission line certificate required further analysis to select a centerline in the two-mile wide corridor that had been granted in the Certificate. The DNRC staff worked with MPC staff and landowners to select a centerline and were working their way west from the plant to Hot Springs. The centerline had been selected as far as Helena when the Confederated Salish and Kootenai Tribe, through whose reservation the line had to travel to reach the Hot Springs Substation, announced they would not grant an easement for the line. Montana Eminent Domain law does not apply on the reservation. At that point, MPC asked BPA to build the western portion of the line on a right-of-way it already owned through the reservation. BPA agreed to take over responsibility for the line west of a point near Townsend, Montana, and began its own transmission routing studies. Under Federal interagency land management rules the US Forest Service was designated the lead agency in conducting the transmission routing review. The Forest Service

reviewed the DNRC studies and conducted its own, and concluded that a termination point at Taft was preferable to one at Hot Springs. The Forest Service proposed a different route than that approved and Certified by the Board of Natural Resources. The two alternatives diverged at Townsend. The original route traveled north via Helena and Jocko Pass, and traveled across the Flathead Reservation to Hot Springs. The route approved by the Forest Service instead traveled around the south foothills of the Elkhorn Mountains, and west toward Deer Lodge and Missoula. It then roughly followed a course parallel to and several miles south of I-90 to a new substation at Taft, near the Idaho border.

The state and federal agencies cooperated on holding public hearings on the route and on adjustments to mitigate environmental and public concerns. Issues included visual impacts in the Boulder Valley, Maxville, Rock Creek and Missoula (mitigated by looping the route around sensitive areas; interference with small aircraft navigation at Boulder Hill and Rock Creek (mitigated by installation of strobe lights on the towers, which worsened visual impacts) and increased public access to sensitive wildlife areas (mitigated by closure of access roads). The line was completed around 1983.

Ownership of the line was complicated, and it became more complicated by BPA participation. Puget and MPC contributed their investment in the single circuit 230 kV Colstrip-Broadview to the project in return for 330 MW each of rights on the 500 kV line to Broadview. (This totaled \$13.3 million.) In addition, Puget paid approximately \$11.1 million for 330 MW of capacity between Broadview and Townsend. The other owners paid their proportionate ownership share of the project for the costs of the project (MPC's share of units 3 & 4 was 30 percent), adjusted by the credits given to MPC and Puget. The capacity of the line was about 10 percent greater than the collective Colstrip transmission, so each of the project owners had more capacity than they needed.

The original negotiations called for BPA to segregate its costs for Townsend-Garrison into an "Eastern Intertie" rate, on which the users would pay wheeling rates that recovered costs for that segment; the remainder of the line from Garrison to Taft would be incorporated in (and costs rolled into) the BPA main grid system (the Federal Columbia River Transmission System, FCRTS). As construction was underway BPA became interested in rights on the eastern half of the line to satisfy WAPA's desire to be able to move surplus Missouri River power to its California loads. Therefore BPA traded rights from Townsend to Garrison in return for rights to access the line between Broadview and Townsend. In separate negotiations MPC provided access for WAPA across its system from Crossover to Broadview. The interparty agreement covering the entire Broadview to Garrison path describes the line as the "Montana Intertie" – as distinct from BPA's rate language which describes the Townsend-Garrison segment as the Eastern Intertie.

In addition, Montana Power had to deal with the impacts of its battle over putting the generating plant in rate base. When Colstrip 3 was completed, MPC brought the plant in for cost recovery as meeting the "used and useful" test. The Commission rejected this argument and asserted it had warned MPC in its testimony before the Board of Natural

Resources that it would not allow the plant in rate base. MPC appealed the decision and the case was eventually settled. However as a result of the acrimonious dispute (and perhaps in anticipation of additional legal challenges) MPC also announced that it would not ask ratepayers to pay for its share of Colstrip 4. Instead, when Unit 4 was completed MPC sold its ownership to financial interests under a 25-year sale and leaseback arrangement that extended to 2010, with a repurchase option at the end of the leaseback. MPC then sold the power from the plant to Puget Power and to LADWP. The Puget sale continues under a long term contract. The LA contract was terminated several years after signing, with a damage settlement to MPC, and the power was then sold to Duke, a power marketing subsidiary of the North Carolina utility.

Montana Power's investment in the Colstrip transmission lines included half of the original cost of the first circuit from Colstrip to Broadview, which as mentioned above was contributed and credited to its 30 percent share of the costs for the 500 KV line. Except for a 210 MW prorated share of its investment (held out as associated with Colstrip 4), this was included in MPC's transmission investment rate base for Montana ratemaking purposes as well as in its FERC rate base for FERC-jurisdictional wheeling rates. MPC's share of the excess capacity due to the lumpiness of transmission design was implicitly in rate base as none was allocated to Colstrip 4. Therefore the exchange credit was also attributed to rate base. MPC (now Northwestern) earns its state-jurisdictional rate of return on this investment, net of other transmission income, through its charges to its default supply customers. Transmission income from non-default supply customers includes use of the Colstrip transmission system by PPL to sell its share of Colstrip and other former MPC generation to west coast purchasers, use of the Northwestern transmission system by other utilities in Montana, mainly coops, to import power into their systems, and occasional use by other parties such as WAPA and BPA to move power over the Northwestern system. Because a 210 MW share of the transmission costs were held out of rate base, there is no wheeling income for use of the lines by its unregulated share of Colstrip 4; in effect Colstrip 4 owns its own share of the line.

Summary Observations

- The Colstrip transmission case covers multiple states (MT, ID, WA, OR) and multiple participating parties (MPC, PP&L, WWP, PGE, PSPL, BPA).
- Contentious regulatory issues before the Montana PSC and DNRC focused on the approval and cost recovery for the generation sources. Problems obtaining cost recovery for generators Colstrip 3 and 4 led to complications in cost recovery for the associated transmission line expansion.
- The transmission proposal also ran into complications in identifying a route through tribal lands and gaining state and federal agency approvals.

Lessons from the 3 RMATS Region Case Studies

The three RMATS region cases examined (Valmy, Sigurd, Colstrip) involved multi-state, multi-company transmission investments in the past 25 years.

- **Economic conditions drive investment in multi-state, multi-company transmission facilities.**

In all cases, economies of scale led to investment in large coal-fired generating facilities. Transmission investment was coupled to the large coal-fired generating facilities for two reasons: First, it was often economic to locate the plants close to the coal rather than to the load, thus transmission investment was often an integral part of the power plant investment decision. Second, since the plants were often larger than the load growth of a single utility, investors partnered on plant ownership and built transmission to share the power and to facilitate the marketing of the power to loads in neighboring utility systems. In this way, utilities were able to manage the disallowance risk of violating the used and useful standard employed by many state commissions for cost recovery determinations.

- **Multi-state, multi-company transmission facilities must be timed with resource decisions and coordinated with multiple stakeholders often with diverse interests.**

The public interest perspective, even though confined to a state jurisdiction proceeding, is broad and complex. Public interest issues included environmental impact, land rights, ownership and therefore proceedings were lengthy and comprehensive. Coordination of stakeholder interests and timing of proceedings is crucial to success.

B. Transmission Cases from Other States

1. Nevada – Alturas

The Alturas case involved a Sierra Pacific Power Company transmission line rated at 300 MW from the California-Oregon Border (COB) Intertie at Malin, Oregon, across the northeast corner of California and into Nevada. The Alturas line was approved in an IRP in 1994 and energized in 1999. At the time of this case, at its maximum rating the Northwest Intertie could deliver 4800 MW to the COB. The California-Oregon Intertie (COI) was capable of taking 4800 MW at the COB for delivery into California.

With both the COI and Alturas in operation, the Northwest Intertie would be unable to deliver the maximum power that each downstream line could accommodate. The Alturas case at the FERC essentially involved a contest between California and Nevada. California argued that the Alturas line would reduce the ability of California utilities to access the full 4800 MW that they had previously been able to off-load at COB. While their arguments were generally cast in terms of system reliability and resource adequacy, the underlying issues related to the California's continued access to less costly power and the need to replace this lost capacity with alternative resources.

Sierra Pacific and the State of Nevada asserted that the Alturas line was consistent with the FERC's policies on open access and merely represented access to the Northwest market for customers in Nevada.

After encouraging the parties to settle the Alturas case, the FERC eventually had to step in and resolve the case in a contested proceeding. In ruling for Sierra Pacific, the FERC noted that this was not a "loop flow" case. While the presence of the Alturas line would change power flows (decreasing flows into northern California and increasing them into Nevada), no other ancillary flows of any significance were involved. Rather, this case involved the division or allocation of an existing resource (the Northwest Intertie) among a greater number of buyers, essentially to the detriment of California. In short, this case was about whether Nevada could gain access to a market and not about inadvertent power flows.

In terms of costs, this line is wholly-owned by Sierra Pacific, and though a multi-state line, its costs should be largely recovered in a vertically bundled retail rate.¹⁷

2. California – Path 15

Path 15 is an existing North-South transmission corridor within the State of California comprised of two existing transmission lines. This transmission facility is often constrained for both north-to-south transmission and south-to-north transmission. As recently as the years 2000 and 2001, these constraints have led to numerous "Stage 3" emergencies in California, as well as some rolling blackouts in California. In March of 2001, the California PUC ordered PG&E to file an application for a Certificate of Public Convenience and Necessity to construct additional transmission facilities to relieve the Path 15 constraints. In April of 2001, PG&E filed its conditional application.

In November of 2001, a group including WAPA, PG&E and Trans-Elect announced a Memorandum of Understanding to construct an upgrade to Path 15. As structured, WAPA and Trans-Elect are the lead partners in the project. WAPA would be the owner-operator of the line and Trans-Elect would facilitate financing of the project.

Essentially because WAPA, a federal power agency, is leading this project, the California PUC's jurisdiction is limited to review of environmental impacts and determinations regarding PG&E upgrades of substations for interconnection to the transmission line. In May of 2003, the CPUC approved the environmental impact statement filed by PG&E, found the substation upgrades to be exempt from approval requirements and granted PG&E's Motion to Withdraw its Application.

Path 15 was energized in mid-December 2004. Cost recovery is governed solely by a FERC approved tariff.

¹⁷ Nevada does allow large customer to buy directly in the wholesale market, so there may be some exceptions to this.

3. Southwest Connecticut

This is a case which has been recently decided by the FERC. Southwest Connecticut is an area of the ISO-NE that is severely constrained and requires significant upgrades (or potential demand-side non-transmission alternatives). The FERC proceeding involved a generic cost allocation proposal put forward by ISO-NE and NEPOOL that would apply both to the Connecticut problem and to other future projects.

The basic issue in this case was whether the SW Connecticut upgrade cost would be allocated to consumers in the affected sub-region (i.e. SW Connecticut) or be “socialized” across the entire region. ISO-NE and NEPOOL proposed to adopt a cost allocation scheme under which transmission upgrades that provide only local benefits would be receive local cost support while those where beneficiaries could not be clearly identified and which produce regional benefits would receive regional cost support. “Local Benefit Upgrades” are defined as ones that are rated below 115 kV or, if rated above 115 kV, do not meet all of the non-voltage criteria for Pool Transmission Facilities. Localized Costs are costs associated with Regional Benefit Upgrades that are not reasonable to be supported on a regional basis. Examples of the latter might be local requirements for placing transmission facilities underground.

Under the ISO-NE/NEPOOL approach, socialization of costs is the “default” treatment, provided the upgrades are “Reliability Upgrades” or “Economic Upgrades.” Reliability Upgrades are ones that are not required by the interconnection of a generator but that are nonetheless necessary to ensure continued reliability of the NEPOOL system. Economic Upgrades are ones that provide net economic benefits to the region.

The Maine Public Utilities Commission, the Maine Public Advocate, the Rhode Island Public Utilities Commission, the Rhode Island Division of Public Utilities and Carriers, the Rhode Island Attorney General, Pinpoint Power, NRG Energy, Inc. and Gen Power, LLC (the “Coalition”) opposed the ISO-NE/NEPOOL cost allocation approach. The Coalition argued that the proposed cost allocation scheme would provide regional cost support for virtually all transmission upgrades and is incompatible with location marginal pricing principles previously endorsed by the FERC. They proposed 25% regional, 75% local cost recovery scheme for all regional plan-approved transmission facilities. In short, these parties objected to sharing the costs of the SW Connecticut upgrades which they viewed as local to Connecticut.

Central Maine Power and PSEG joined the Coalition to voice their concern that the bias in favor of socializing costs would favor transmission solutions over other, more economic, alternatives, such as local generation or customer-initiated load response, which would not enjoy the subsidies of socialization.

Citing its policy of deference to regional choices and the broad support among NEPOOL members for the proposed cost allocation scheme, the FERC approved the ISO-NE/NEPOOL approach. In addition, it dismissed concerns about locational marginal

pricing because the socialized cost allocation scheme comes into play only if market-based solutions fail to come forward. Moreover, it found that the scheme is warranted because of the associated increased certainty of cost recovery for new facilities.

It is probably a fair to observe that, while the FERC was concerned with appropriate cost recovery schemes, it was also interested in supporting the regional mechanisms in the context of the FERC's overall wholesale market policy and the recent shortcomings of its Standard Market Design.

Observations and Lessons from the Case Studies Outside the RMATS Region

These four transmission line cases provide some insight into the variety of problems and issues associated with transmission line planning and cost recovery. These cases highlight three issues of particular interest – 1) the close relationship between broader system planning issues and transmission planning, 2) the importance of non-technical issues, such as ownership, which can alter the jurisdiction over the facilities and facilitate the construction of facilities that might not otherwise get built and 3) the importance and relevance of a regional/state process that the FERC might defer to when confronted with specific transmission cases.

For example, in the Alturas line case it is quite clear that California built facilities which were exactly matched to receive power from the Northwest Intertie. The introduction of the Alturas line essentially diverted a portion of the power supply to another destination, leaving California with less of a resource than it had counted on. There is no clear, “easy,” answer to this type of problem, especially in a “market” environment. This case demonstrates that not all conflicts may be suited for a regional solution, because neither party would accept an answer it didn't like. FERC (or the Courts) is an appropriate venue to decide whether CA had rights to power from the Northwest that would be infringed by Nevada access.

The Path 15 case demonstrates the consequences of our shared Federal-State jurisdiction over transmission. By modifying the ownership structure through the inclusion of a federal agency, in this case WAPA, state jurisdiction over the line was greatly reduced (essentially down to environmental impact issues). This approach may become a model for transmission owners seeking to construct facilities that may otherwise face state-level opposition. To the degree parties use ownership structure to circumvent due process (state level review and potential opposition) this approach may produce inefficient results.

Finally, the ISO-NE/NEPOOL case is a good example of the potential cost recovery controversies that can ensue when costs are spread according to a regional or multi-utility or multi-state consensus. It is interesting to note that regional, multi-utility or multi-state agreements are valuable but may still encounter opposition in either the interpretation or application of the agreement or perhaps the underlying technical analysis. However, FERC has ultimate jurisdiction and this process appears to work – projects have weathered the storm of conflict because there is a venue for decision. In a FERC

proceeding, States and other interested parties may intervene to have their point of view heard.

However, the Connecticut decision is also disturbing and raises implications for a Grid West or Western Interconnect solution. It raises an efficiency problem associated with socialization of risk – particularly if we intend to base investment decisions on regional plans. Regional modeling may be indicative of potential benefits and their distribution, but regional planners may be ill-suited to make judgements about the willingness to accept the risk of paying for something that may turn out differently than expected. That role – both for decision-making and for risk-bearing – may belong with the parties who think they will benefit, not with a governmental, quasi-governmental or cooperative planning body.

CHAPTER III: STATEMENT OF COST ALLOCATION PRINCIPLES

The Southwest Power Pool (SPP) Principles

The TREG Workgroup identified a number of principles that could be observed for transmission cost allocation. To a large extent, we started with principles articulated by the Regional State Committee for the Southwest Power Pool and modified them for application in the CREPC context. The SPP Principles are set forth in Attachment A, below.

The SPP principles, and the related cost allocation process, categorize projects as “Base Funded,” “Economic,” “Requested,” or “Generation Interconnection.” Base Funded Projects are generally those that are required for continued reliability of the grid and are slated by the RTO as part of its general system expansion plan. Economic Projects are those that may defer or avoid one or more Base Funded projects. Requested Projects are those that have been proposed outside the ordinary planning process by specific transmission owners or users and are not eligible for regional cost allocation or recovery. Likewise, Generation Interconnection projects are specific to the generating projects with which they are associated.

We have assumed that the costs of projects in the West that SPP would classify as Requested Projects and Generation Interconnection Projects would be assigned directly to the parties involved and do not involve allocations to other transmission owners or users. To the extent that such projects exhibit both specific benefits for identified users and common benefits for other users, then the common portion of such costs would be subject to the principles identified here.

Application of SPP Principles to the West

It is important to understand the broader context within which decisions are made for selecting any given project. Unlike in the SPP, there is no RTO or its equivalent on a West-wide basis. Thus, successful transmission planning must be conducted on a cooperative basis, and transmission investment cost recovery for a specific project is subject to state and/or federal approval. This process is expected to continue for the foreseeable future.

In addition, utilities in the Western Interconnection are predominantly subject to integrated resource planning (IRP) or other least cost requirements. However, Wyoming, for example, does not have a mandatory IRP process, but subjects transmission investments to examination in the rate making context. Although purely merchant transmission development has attracted serious interest in the West, it is reasonable to expect that most major transmission investments are going to be undertaken by utilities within an IRP-type environment. Even utility-built transmission, however, may be built for the purpose of simply accessing wholesale markets.

Finally, where a project is essentially intrastate in character and all of its costs are intended to be recovered from native load customers within one state or utility system, these principles generally do not apply because a single commission, or multi-state allocation procedure would be overseeing the inclusion of costs in retail tariffs. Even in these cases, however, a state might refer to these principles for guidance and consistency.

Draft Principles for Consideration

Introduction

The basic cost allocation principles outlined here are not significantly different than those that have traditionally been used in multi-state utility allocations. However, because of the increasingly “regional” nature of the system, the institutional framework for reviewing transmission level projects has been and continues to be wanting. Because of the ownership and regulatory structure of the Western electric transmission system, an institutional framework for reviewing transmission level projects that is somewhere between the interconnection-wide WECC view and a State’s or utility system’s more locally focused view, is missing. These principles have been organized around the notion that a regional or subregional process will be undertaken to afford the various stakeholders the ability to ascertain the impact, in both engineering and economic terms, of proposals and their alternatives.

Because of the interconnectedness of costs, cost impacts, and benefits inherent in the Western Interconnection, it is imperative that any cost allocation scheme be reflective of an IRP or least cost planning standard. As such, we view the regional or subregional processes contemplated by these principles to be as important as the cost allocation mechanisms themselves. It is because of this that we have included these processes as part of the statement of draft principles.

Our Transmission Scenarios Matrix describes a variety of reasonable ownership and topographical configurations in which new transmission might be built. These configurations are useful for relating aspects of project ownership to regulatory processes and jurisdiction. In terms of principles for cost allocation, however, an equally crucial characteristic is the purpose for which the transmission is built, as this provides the underlying rationale for the allocation of its costs. That is, is the transmission line to be built for the provision of retail service to the transmission owner’s native load, or for generic wholesale market access

Transmission Cost Types

While the SPP Principles and cost allocation scheme revolve around the notion of “base funded,” “economic”, “requested”, and “generator interconnection” project categories, these Draft Principles are developed around a different classification approach. We found that the use of SPP’s categories has led to some confusion, mostly of a semantic nature, and so have opted for a neutral classification scheme built around the costs related to the end-use characteristics of the transmission line. Because transmission lines might

be built and owned by multiple parties, each of whom may have different uses in mind, any given transmission line could, in fact, include multiple types of costs. For purposes of the Draft Principles, the types of transmission line costs are:

- Type 1 transmission line costs are those related to the provision of retail service to the transmission owner’s native retail load. Type 1 costs may have the following sub-types:
 - Type 1-A transmission line costs are those incurred by a single load serving entity for its native load within a single state.
 - Type 1-B transmission line costs are those incurred by a single load serving entity for its native load in more than one state.
 - Type 1-C transmission line costs are those incurred by more than one load serving entity for native load within one state.
 - Type 1-D transmission line costs are those incurred by more than one load serving entity for native load in more than one state.
 - Type 1-E transmission line costs are those incurred to provide service for, to lower the costs of, or to increase the quality of service for a specific retail customer or specifically identifiable group of retail customers. While there may be some “generic” benefit to other retail customers, those benefits would be incidental to the primary purpose of the line.

Type 1 costs might be incurred to:

- a. Provide capacity needed to serve load;
 - b. Fulfill reliability or other technical operating requirements, the benefits of which generally inure to the consuming public; or,
 - c. To lower costs for the general consuming public (e.g. congestion relief that provides access to cheaper, remote generation).
- Type 2 transmission line costs are those related to the sale or purchase of power at wholesale, or on behalf of or at the request of a wholesale generator or a wholesale transmission customer. Type 2 transmission line costs will typically be FERC jurisdictional and not subject to state review. However, to the extent that the physical transmission line associated with these costs might also have Type 1 characteristics, a state may allocate costs to retail rate payers. As discussed in Part I, Regulatory Landscape, states have three ways to include transmission costs in retail rates (bundled, functionally unbundled, functionally and service (retail versus wholesale) unbundled). Depending on the method used, either the utility shareholders or the utility customers bear the risk of differences in FERC and state cost recovery decisions.

- Type 3 costs are those incurred specifically as alternatives to (or deferrals of) transmission line costs (typically Type 1 projects), such as the installation of distributed resources (including distributed generation, load management and energy efficiency). Type 3 costs do not include demand-side projects which do not have the effect of deferring or displacing Type 1 costs.

For purposes of these Draft Principles, it is critical to keep in mind the distinction between transmission projects and transmission cost types. Any given transmission project may have multiple transmission cost types. For example, a transmission line may be jointly owned by owners who utilize the line for different purposes (one owner may utilize the line for native load, while another utilizes the line for access to wholesale markets); and even for a single owner, the line may serve multiple purposes (part native load and part direct off-system sales to another transmission user). These Principles are built around the characteristics of the associated *costs*.

TREG Draft Principles

Draft Principle 1

Principle Type: Equity

Applies to Transmission Cost Types: Type 1, Type 2, and Type 3

As a matter of equity, cost allocations should reflect the classic principles that “cost causers should be cost bearers” and that “beneficiaries should pay” in amounts that are reflective of the benefits received.

Discussion:

This principle is consistent with traditional utility cost recovery principles historically applied by utility commissions. However, the “cost causer” concept and the “beneficiary” concept are not necessarily identical. That is, there may be many situations where the problem being solved is “caused” by one party, but where the solution being applied also provides benefits to others or increases costs to others (e.g. the Alturas case). As such, application of this principle necessarily implies a balancing of these interests.

This principle presumes that the term “benefit” includes transmission service allocation meaning transmission rights, whether physical or financial, and that allocation of service rights is consistent with cost allocation. Further, the funding party of a project should retain its rights as market design, e.g., formation of an ISO, evolves.

In the SPP, for “Base Funded” projects, this problem is addressed through the use of an arbitrary allocation of costs. One third of the cost is allocated on a region-wide basis. The balance of the cost is allocated to the identified zone or zones that benefit from the project, using an “incremental MW mile” approach.

Implementation Requirements:

As this is purely a statement of the conceptual basis for cost allocations, no formal institutional changes are necessary to implement this principle, other than an affirmation by each state that it intends to recognize this principle in the consideration of any given transmission project. In this regard, such recognition might be included in an informal memorandum of understanding.

Draft Principle 2

Principle Type: Efficiency

Applies to Transmission Cost Types: Type 1, Type 2 and Type 3

Selecting an efficient portfolio of remote generation, in-state generation and demand-side solutions such as DSM, distributed resources and energy efficiency programs requires that the allocation of the cost of transmission projects to remote generation be known with some level of certainty. Therefore, regional and sub-regional processes should promote efficient resource planning processes by seeking to identify a consensus cost allocation principle for a regional transmission project as soon as practical in the project life cycle so that individual state's can evaluate the proposed project relative to other resource options.

Discussion:

All Type 1 projects should be subject to an overall productive and allocative efficiency requirement, including comparisons to Type 3 projects. To assure that “system” costs are efficiently incurred, this process should include an “all-source” or “open season” review in which non-transmission alternatives are considered, including DSM, energy efficiency and distributed resources.

The SPP principles do not specifically address this type of efficiency and do not provide for treatment of demand-side alternatives to transmission facilities.

Implementation Requirements:

Presently there is no formalized multi-state process for the review and approval of transmission projects. Projects are currently identified or proposed through a variety of channels. These include utility sponsored projects and “regionally identified” projects that are formulated by established organizations (such as WECC) or by ad hoc groups (such as RMATS).

Once such projects are proposed they must obtain all required state and local approvals as described in Part I and including IRP (if required), CPCN, siting, etc. The flow of this process tends to be somewhat unidirectional in the sense that a project is identified and is

then subjected to state review. If it survives the review processes of the various states, it then proceeds to financing and construction. The primary short-comings of this approach are that it may not properly identify alternatives at the regional or sub-regional level and does not iterate through the economic value of alternatives to the proposed project at the regional or sub-regional level.

Currently IRP and least cost analyses are typically done on a state by state or single utility system basis. Because demand-side alternatives are, by definition, local in nature, they have traditionally been identified and funded by each state. However, this approach may fail to recognize opportunities for increased efficiency across the region or sub-region. For example, an IRP review in State or utility system A does not consider the cost savings associated with demand-side alternatives in State or utility system B.

Fulfillment of Draft Principle 2 would be greatly enhanced with the implementation of a regional or sub-regional IRP review of all Type 1 projects. This necessarily includes a review of other projects, including Type 3 projects. The current processes do not assure that this takes place at all. Draft Principle 2 recognizes this deficiency and encourages cooperative engagement early in the project life cycle of a specific project.

States should encourage regional and sub-regional analyses that provide an IRP review of Type 1 projects, including consideration of Type 3 alternatives. In this regard, it would be useful to have a broad framework outlining how such a process would be undertaken and the analytical standards that might be used. An informal memorandum of understanding among state commissions may be helpful in this regard.

Draft Principle 3

Principle Type: Allocation

Applies to Transmission Cost Types: Type 1 and Type 3

Cost allocations for Type 1 and Type 3 projects should result in a reasonable opportunity for the transmission owner(s) to achieve full recovery of the costs of the project, but no more.

Discussion:

In any case where a Type 1 or Type 3 project is required, all of the costs of the project should be fully recoverable. Fully one hundred percent of the costs of multi-state projects (Types 1-B and 1-D) should be allocated to one or more utility systems. There should be no gap and no double recovery of these costs.

Historically, utilities have largely recovered multi-jurisdictional costs through allocation mechanisms that were, for the most part, sufficiently consistent to allow recovery of all costs. While there are legal standards that would support full cost recovery at the state and federal level, there have never been formalized rules to assure full cost recovery.

Indeed, state and federal standards that prohibit rates that are confiscatory to the utility or excessive to customers demonstrates the careful balance that must be achieved in setting rates.

The principles of cost causation and equity among customers has prevented inadequate cost recovery from becoming a large problem in most cases. Nonetheless, at least one utility, Pacificorp, agreed to accept the risk of state cost allocation differences and faced multi-state allocation problems which appear to be resolved for the time being after intensive work by the state regulatory jurisdictions and the company in agreeing to a revised interjurisdictional allocation Protocol coupled with stipulated additions in the various states to address the specific needs of individual jurisdictions.

Implementation:

States should endeavor to implement this principle going forward in the cases of Type 1 and possibly Type 3 cost allocations. An informal memorandum of understanding among state commissions may be helpful in this regard.

Draft Principle 4

Principle Type: Allocation

Applies to Transmission Cost Types: Type 1 and Type 3

Type 1 and Type 3 project costs should be directly assigned to a single transmission customer or allocated to multiple transmission customers (and/or zones), or the entire region, based upon the distribution of benefits.

Discussion:

To the maximum extent possible, the costs of Type 1 and Type 3 projects should be allocated to the regions or zones that received the benefits of the project. This is an extension of Draft Principle 1.

Preferably, in order to provide cost recovery assurance to project owners and to avoid post-construction cost allocation controversy, expectations of the project owner for the allocation of costs should be identified in the regional or sub-regional review process, prior to construction. While it is unlikely that any state would endorse “pre-approval” of cost recovery, especially in the regional or sub-regional context, it would be helpful for the project owner to be engaged early in the process and the expectations of the project owner to be clearly identified during any regional or sub-regional review.

Implementation:

No formal action is required with respect to this principle. However, an informal memorandum of understanding among state commissions, recognizing this principle, may be helpful.

Draft Principle 5**Principle Type: Allocation****Applies to Transmission Cost Types: Type 1-E**

Customer Specific Upgrades: Projects proposed on the basis of economic or other benefits for specific transmission customers should be accommodated, on the condition that the customer and/or the transmission owner accept responsibility for the associated costs and provided the project does no harm to the network and otherwise has no adverse impact on regional transmission service

Discussion:

In cases where transmission customers require specific projects that are not otherwise identified as Type 1-E, cost recovery should be limited to the affected customer or customers.

Implementation:

No formal action is required for implementation of this principle. However, an informal memorandum of understanding among state commissions, recognizing this principle, may be helpful.

Draft Principle 6**Principle Type: Allocation****Applies to Transmission Cost Type: Type 2**

For Type 2 project costs, the rest of the network and its customers should be held harmless and the transmission owner should look to its transmission customers for direct recovery of costs.

Type 2 should be regarded as generally being outside the scope of regional or sub-regional cost allocation mechanisms. The merchant transmission owner should look only to its customers for recovery of costs. As a general rule, it is expected that Type 2 costs are subject to the exclusive jurisdiction of the FERC. It is expected that conflicts in

defining and adjudicating “harm” will be resolved at the appropriate state or federal regulatory body.

Merchant transmission projects will connect to the grid and should therefore be reviewed for their impact on its stability and capabilities of the rest of the Western Interconnection, including any costs they might impose or advantages they might create for other users of the system.

Attachment A

The Southwest Power Pool Transmission Cost Principles

The SPP developed the following principles for transmission cost responsibility:

SPP Principle 1 (Equity): The cost allocation policy should reflect the classic principles of “cost causers should be cost bearers” and “he who benefits should pay.”

SPP Principle 2 (Equity): The cost allocation of a transmission service to meet a request or need for transmission service should not result in the cost causers being required to pay for more than is received in transmission benefits.

SPP Principle 3 (Equity): The cost allocation policy for transmission expansion, transmission access pricing and transmission service allocation (whether physical or financial) should, when combined, reflect the principle that there are no “free riders” and that similar transmission service is allocated and priced indiscriminately.

SPP Principle 4 (Efficiency): The cost allocation policy should send appropriate signals to generators to efficiently locate their plants on the grid.

SPP Principle 5 (Competitive Supply): The cost allocation policy should encourage competitive supply of electricity in wholesale markets for generation.

SPP Principle 6 (Reliability): Each transmission owner should fund, and recover the approved costs of, transmission projects to meet the SPP reliability standards, replace obsolete facilities, and meet growth in demand.

SPP Principle 7 (Allocation): Transmission expansion projects resulting from the RTO’s plan that are intended to provide economic benefits may be allocated to single or multiple transmission customers (and/or zones), or the entire region, based on the RTO’s estimate of distribution benefits.

SPP Principle 8 (Voluntary Economic Upgrades): For a non-reliability project, a transmission customer should be able to get a commitment from the RTO, as transmission service provider, to construct a requested project that does no harm to the network or otherwise has an adverse impact on regional transmission service, on the condition that the customer accept its allocated share of the costs.

SPP Principle 9 (Retention of Cost Allocation Benefits): The funding party of a transmission project should retain its rights as market design evolves.

CHAPTER IV: THE MATRIX OF TRANSMISSION SCENARIOS AND REGULATORY PARAMETERS

The TREG work group developed a series of hypothetical transmission scenarios in an analytical exercise to identify problems in the current regulatory framework. Discussions about the scenarios led to the creation of a matrix of regulatory parameters to evaluate the hypothetical scenarios. This section describes the assumptions and findings of the transmission scenario-matrix analysis. Where applicable, we have identified cases from Part II that illustrate the scenario. In addition to a more theoretical evaluation, we have also drawn from Part II in evaluating the scenario with respect to each regulatory parameter. Finally, we note the draft principles that apply to each scenario.

The seven scenarios represent a spectrum of transmission projects ranging from a simple case followed by scenarios with more complex and difficult regulatory issues.

- First scenario – Single utility transmission project that connects to the same utility’s generation to load within a single state.
- Second scenario -- Single utility sponsors a transmission project over multiple states to connect to utility owned generation to load. An example of this scenario is the Alturas case study discussed in Part II.
- Third scenario -- Multiple utility sponsored transmission project that connects to multiple utility owned generation to load. This scenario captures the facts of the Colstrip case study discussed in Part II.
- Fourth scenario – Multiple utility sponsored transmission project that connects non-contracted non-utility generation to load. An example of this scenario might be the California-Oregon Interface (COI) discussed in the Alturas case study in Part II.
- Fifth scenario – Utility sponsored transmission project to enable non-contracted generation to access markets. This scenario captures the facts of the Tehachapi upgrade case study discussed in Part II.
- Sixth scenario – Merchant sponsored and financed transmission project that connects contracted generation to load.
- Seventh scenario -- Merchant sponsored and financed transmission project that enables non-contracted generation to access markets.

Each scenario is evaluated by the following five regulatory parameters: (1) need determination; (2) interstate siting issues; (3) cost recovery issues; (4) efficiency issues; and (5) need for regional coordination process.

The analysis of these parameters for the seven scenarios is summarized in the transmission matrix below.
Transmission Scenarios Matrix

Fact Pattern	Need Determination	Interstate Siting Issues	Cost Recovery Issues	Efficiency Issues	Need for Regional Process
<p>1. Single-utility-sponsored transmission line to connect utility-owned generation to load (single state transmission).</p> <p>Project Type: Type 1-A and Type 1-E</p>	<p>Per Requirements of Individual States</p>	<p>None.</p>	<p>Draft Principles 1, 3, 4 and 5 apply. Cost recovery addressed per state process, conflicts resolved there.</p>	<p>Draft Principle 2 applies. Absence of regional coordination may result in less economic choices, but single state commission jurisdiction and use of IRP process mitigates this risk. Some potential economic impact on other companies/customers due to changes in system flows and market conditions</p>	<p>Regional coordination could identify inadvertent consequences and more economic resource choices should they exist,</p>

Fact Pattern	Need Determination	Interstate Siting Issues	Cost Recovery Issues	Efficiency Issues	Need for Regional Process
<p>2. Single-utility-sponsored transmission line to connect utility-owned generation to load (multi-state transmission). (Example of this is the Alturas line).</p> <p>Project Type: Type 1-B and Type 1-E</p>	<p>Normal issues of need and cost recovery in consuming states only. However, construction of line may create “new” needs in other parts of region.</p>	<p>Interstate siting coordination needed. No unusual need issues in siting – especially if selection of generation and transmission emerged from IRP.</p>	<p>Draft Principles 1, 3, 4 and 5 apply. Multi-state utility system costs are allocated to all system customers. Opposition sorted out on state basis – some risk to utility with FERC recourse.</p> <p>No cost recovery issue for customers in non-consuming utilities if “consuming” utilities/customers pick up all the transmission costs.</p> <p>May have time related issues if generation has contracted for transmission for less than cost recovery life of transmission. Such issues likely to be addressed and resolved in the appropriate regulatory forum. However, if non-consuming utilities build and own, and are at risk for any portion of the costs, then need and cost recovery may be contentious issue in the resource states.</p>	<p>Same as Transmission Scenario 1.</p>	<p>Same as Transmission Scenario 1.</p>

Fact Pattern	Need Determination	Interstate Siting Issues	Cost Recovery Issues	Efficiency Issues	Need for Regional Process
<p>3. Multiple-utility-sponsored transmission line to connect multiple-utility-owned generation to load (Example of this is the Colstrip transmission).</p> <p>Project Type: Type 1-C and Type 1-D</p>	Same as 2		Draft Principles 1,3 4 and 5 apply	Draft Principle 2 applies. Multi-company/ multi-state nature of project may evaluate transmission alternatives well, but not necessarily non-transmission alternatives. Although Utility IRP's may be available, coordinating and evaluating all alternatives likely to be very complex.	Greater need for regional process due to increased complexity of project and increased diversity of interests to address.
<p>4. Multiple-utility-sponsored transmission to connect contracted non-utility-generation to load.</p> <p>Project Type: Type 2</p>	Same as 2.	Same as 2.	Draft Principles 1 and 6 apply. May be issues of jurisdictional states if supplier selection is questioned. However, likely to be resolved before construction. Decision in the Valmy case study in Part II indicates a disallowance of generator cost not reason for disallowance of transmission cost. Under FERC standards, more likely to assign costs to new generator	DRAFT PRINCIPLE 2 APPLIES? Utilities are subject to economic choice tests (e.g. IRP), but may be subject to some built-in bias against non-transmission alternatives, due to rate making treatment differences between supply-side and demand-side investments.	Same as Transmission Scenario 3.

Fact Pattern	Need Determination	Interstate Siting Issues	Cost Recovery Issues	Efficiency Issues	Need for Regional Process
<p>5. Utility-sponsored transmission to enable non-contracted generation to access markets. (Example of this is the Tehachapi upgrade).</p> <p>Project Type: Type 2</p>	<p>Big issues of need and cost recovery for the sponsoring transmission utility – may be an issue in siting and need determination. Draft Principles 1 and 6 apply.</p>			<p>DRAFT PRINCIPLE 2 APPLIES? Need for clear determination of cost recovery mechanisms – that is, who will pay and who bears the risk.</p>	<p>Same as Transmission Scenario 3.</p>
<p>6. Merchant sponsored (and financed) transmission to connect contracted generation to load. (Example of this is possibly the Path 15 upgrade).</p> <p>Project Type: Type 2</p>	<p>(Same as Transmission Scenario 2)</p>		<p>Draft Principles 1 and 6 apply. No cost recovery regulatory issues</p>	<p>DRAFT PRINCIPLE 2 APPLIES? Essentially operates outside the realm of commission reviewed economics. Therefore, should be subject to appropriate structure to assure that non-transmission alternatives “compete” on a level basis.</p>	<p>Need for regional process to address “adverse” or “unintended” aspects to properly assess impact of new facilities on system and non-participating utilities</p>
<p>7. Merchant sponsored (and financed) transmission to enable non-contracted generation to access markets. (Example of this is possibly the Path 15 upgrade).</p> <p>Project Type: Type 2</p>	<p>Big issues of need and risk in transmission siting.</p>		<p>Draft Principles 1 and 6 apply. No cost recovery regulatory issues.</p>	<p>Same as 6</p>	<p>Same as 6</p>

The first scenario represents the simple case where a single utility sponsored transmission project connects utility owned generation to load. This fact pattern reflects the historic period when vertically integrated utilities owned and operated the infrastructure to serve its own load. We anticipate that this scenario would encounter little or no opposition in placing the line in the rate base with full cost recovery.

The second scenario follows the first scenario with the added element that the transmission line passes over multiple states. This scenario follows the facts of the Alturas case. Cost recovery would apply in a normal fashion to consuming utilities and customers. There would not be a cost recovery issue for non-consuming states. In the single state case, the generation and transmission costs are all allocated to the utility in that state. In the multi-state scenario with utilities like PacifiCorp, the participating states adhere to cost allocation agreements.

The third scenario assumes a multiple utility sponsored transmission project that connects multiple utility owned generation to load. This scenario captures the facts of the Colstrip case. The need determination, interstate siting issues, and cost recovery issues are the same as in scenario two. The addition of multiple utility sponsors potentially complicates the big picture analysis for efficient utilization of resources over the region. In the single utility scenario like with PacifiCorp, a single IRP analysis would identify the least cost options. Unless there was a regional process to compare options, the multiple utility case could lead to inefficient system-wide resource allocation.

The fourth scenario continues the multiple utility sponsored transmission project but now assumes non-utility generation to load. The need and interstate siting issues are the same as in scenario two. The non-utility generation feature may raise issues of cost allocation in jurisdictional states if the specific generator choices are challenged by critics.

The fifth scenario returns to a single utility transmission project but assumes the project connects non-contracted generation to access markets. This scenario represents the Tehachapi case. As the Tehachapi case demonstrated, the sponsoring utility (e.g. SCE) faces difficult issues of cost recovery and could face problems for siting and need determination.

The sixth and seventh scenarios postulate a regional/marketer/generator sponsored and financed transmission project. In the sixth scenario, the transmission project connects contracted generation to load. The seventh scenario assumes the new transmission links non-contracted generation to access markets. Both scenarios involve parties outside the realm of PUC/PSC economic review and suggest a need for regional processes to assess the impact on the entire system on non-participating utilities. Both scenarios also do not raise cost recovery issues. Scenario seven differs from six in that it raises significant issues of need and risk that are relevant for transmission siting.

Implications for RMATS Projects

The transmission scenario matrix analysis can be applied to evaluate the implications for the various RMATS transmission proposals.

RMATS Recommendation 1 identified three non-export transmission projects; (i) the Montana system upgrade; (ii) the Bridger expansion project in Wyoming, Utah and Idaho; and (iii) the Wyoming to Colorado transmission project. These three non-export projects fall into the scenarios three and four in the above analysis, corresponding to transmission cost Types 1-C, 1-D and Type 2. Accordingly, draft principles 1, 2, 3, 4, and 6 apply. These projects involve lines that are owned and operated by multiple utilities that connect utility generation and non-utility generation to load. No significant issues arise in terms of need determination, interstate siting, or cost recovery for consuming states. Regional coordination is important to identify the system-wide need and evaluate non-transmission alternatives. Therefore, the analysis suggests that the RMATS non-export transmission projects should not face unusual regulatory impediments.

RMATS Recommendation 2 proposed four alternative pairs of long distance 500 kV lines to export power from the Rocky Mountain region to the West Coast states. The export proposals match scenario seven assuming that the western state regulated utilities will not undertake export projects. This project corresponds to transmission cost Type 2 and therefore draft principles 1, 2 and 6 apply. Such projects would be sponsored by marketers or generators or utilities in the consuming states. Although these projects do not have cost recovery issues, they face important regulatory problems of need and risk in transmission siting.

All RMATS projects would benefit from regional coordination to help stage the process of regulatory review. The next steps in the process are: utility system IRP review; regional coordination and review; if changes proposed in regional review, utility system IRP review may need to be done again; then CPCN and siting issues will need to be attended to.

CHAPTER V: ALTERNATIVE APPROACHES AND MECHANISMS

A. THE OPEN SEASON PROCESS

An “open season” in the context of natural gas pipelines or electrical transmission expansion refers to a process of solicitation and bidding designed to secure an adequate level of new capacity to support construction of a major new project. The process begins when the sponsor of a project gives public notice about a proposed project and invites potential participants to submit bids if they want to utilize the proposed transmission line or pipeline. The response from prospective participants provides the project sponsor with feedback on the market demand for this project. This feedback enables the sponsor to adjust the scale of the project to meet the revealed market demand, and provides the sponsor with a mechanism to obtain participant funding for the project. This section proceeds with an initial look at the use of the open season process in natural gas pipelines, and then examines two recent applications for electrical transmission expansion.

1. FERC’s Natural Gas Pipeline “Open Season” Policy

The Federal Energy Regulatory Commission (FERC) has incorporated the open season process within a broader policy to price and certify natural gas pipelines. FERC’s open season policy is articulated in multiple policy statements and FERC certification case law over the past 20 years.

FERC issued a 1995 policy statement that endorsed the open season process as a means of mitigating rate increases on existing customers from rolled-in pricing by encouraging capacity releases from existing users prior to approving new construction.¹⁸ In 2000, FERC released a clarifying policy statement elaborating that the open season process is a means to identify relinquished capacity prior to a proposed expansion project.¹⁹ Aside from these two policy statements, FERC has carved its open season policy in case law addressing individual applications for certification.

FERC case law has set precedents governing the procedures to conduct an open season. Pipeline applicants conducting an open season must provide notice of the project, and the

¹⁸ 71 FERC ¶61,241 Docket No. PL94-4-000, Pricing Policy For New And Existing Facilities Constructed By Interstate Natural Gas Pipelines, STATEMENT OF POLICY; (Issued May 31, 1995)

¹⁹ 90 FERC ¶ 61,128 ; Docket No. PL99-3-001 , Certification of New Interstate Natural Gas Pipeline Facilities , ORDER CLARIFYING STATEMENT OF POLICY, (Issued February 9, 2000) (“The Commission has a two-step process for determining whether the market finds an expansion project economically viable. The first step, which occurs prior to the certificate application, is for the pipeline to conduct an open season in which existing customers are given an opportunity to permanently relinquish their capacity. This first step ensures that a pipeline will not expand capacity if the demand for that capacity can be filled by existing shippers relinquishing their capacity.”)

notice must contain specific details about the project and describe in sufficient detail the terms for submitting bids.

FERC recently issued open season proposed regulations that would govern open season policy for natural gas pipelines under the Alaska Natural Gas Act.²⁰ Although not applicable to projects outside Alaska, these proposed regulations represent FERC's current view of appropriate open season procedures. Key elements of the proposed Alaskan open season regulations include the following: (1) Applicants must provide public notice of an open season at least 30 days prior to the commencement of the open season; (2) The notice must provide specified information about the project including the route, size and design, pressure levels, fees and other items; (3) Applicants must provide shippers at least 90 days from the date on which notice is given to submit requests for transportation services

2. NorthWestern Energy's Open Season

NorthWestern Energy (NWE) is exploring new transmission opportunities to link resources in Montana and Canada to potential load markets to the west and southwest. Plans for approximately 2,100 MW of new generation capacity exist within Montana but lack adequate transmission connections. RMATS Phase I proposed an upgrade to transmission capacity in the Montana to Northwest line from Colstrip to Taft. The larger RMATS export scenario proposed a combination of new 500 kV lines linking the Montana-Idaho-Wyoming region to the West Coast. In light of these broader regional proposals, NWE is pursuing an open season process as the means to resolve the chicken and egg problem of what gets built first – new transmission or generation.

NWE initiated an open season process to for expansion of the Montana to Southwest Path (MT-SW or WECC Path 18) that links transmission between Montana and Idaho. The MT-SW path is jointly owned by NWE, Idaho Power Company, and PacifiCorp. This path includes a 230 kV AMPS line and a 161 kV Jefferson line. NWE's southbound AMPS and Jefferson lines are fully utilized on a long term basis. During the summer of 2004, the MT-SW path capacity dropped from 337 MW to 324 MW because the Bonneville Power Administration (BPA) removed its 65 MVAR shunt capacitors at Anaconda. NWE has identified six different improvement options that could cumulatively raise transmission capacity of this path from 324 MW to as much as 1,000 MW. NWE established an open season process to reveal the prospective demand for transmission that would financially support this capacity expansion.

NWE's open season consists of three phases. Phase 1 is the initial expression of interest period. NWE announced the plans for expansion and asks for parties (generators, suppliers, load serving entities) to come forward with statements of interest for new transmission services from October 1-31, 2004. These parties were asked to specify that amount of capacity needed in 25 MW blocks, the direction of service, a start date, and the term of service. At the conclusion of Phase 1, NWE reviewed the level of interest and

²⁰ Docket RM05-1-000; Regulations Governing the Conduct of Open Seasons for Alaska Natural Gas Transportation Projects, NOTICE OF PROPOSED RULEMAKING, (Issued November 15, 2004).

made a determination to that there was adequate market demand to support their open season process.

Phase 2 began in mid-November 2004 with a posting of the time period to accept transmission service requests for the open season process. From December 1-31, 2004, NWE solicited transmission requests on the MT-SW AMPS path as point of receipt (POR) or point of delivery (POD) only and for new capacity. The open season solicitation involved the same process as a transmission service request under NWE's Section 17 Open Access Transmission Tariff except for two elements: (1) the initial deposit with the application was delayed, and (2) the system impact study and study fee was waived. Existing NWE customers with previously completed applications for transmission capacity were deemed part of the open season process and retained their queue positions. After the closing date of December 31, NWE scheduled a 60-day period to review the total transmission requests and options to meet those requests. NWE will post study results on its OASIS site and participants have 30 days to review results and receive proposed facilities study agreements.

Phase 3 begins after NWE posts study results. The open season participants will have 15 days to respond by executing a facility study agreement, and provide a facility study fee and a deposit for transmission service. If participants do not come forward at this point, NWE will deem the reservation withdrawn.

3. BPA's Open Season for the McNary-John Day Transmission Project

The Bonneville Power Administration's (BPA) transmission line entity, the Transmission Business Line (TBL), proposes to build a 500 kV McNary-John Day transmission line with a projected cost of \$167 million. The new 79 mile line from Tri-Cities, Washington to Rufus-John Day, Oregon would add new capacity to the constrained path crossing the West of McNary (WOM)/West of Slatt (WOS) flowgates. TBL undertook an open season to see if there was adequate demand to support this expansion project.

TBL held an initial open season period from July 1 to July 30, 2004. Eligible customers were invited to participate by submitting a transmission capacity request for point to point service or network service consistent with TBL's Section 17.2 of the OATT by the deadline. Applicants in the TBL transmission service queue whose requests could be met by completing the McNary-John Day project would be automatically included in the process. If TBL received sufficient new transmission requests in combination with applicants in the queue, TBL planned on sending out financial agreements based on the pro rata share of project cost for all applicants in the queue in September. Applicants would then be given 30 days to respond to the offers.

The response to TBL's initial open season period in July was apparently inadequate to support the project. In September, TBL announced a supplemental open season period from September 13 to 17, 2004. Interested parties were given another opportunity to submit requests to participate in the project. Parties that made requests in the initial open season period were allowed to re-submit their requests. TBL is currently reviewing the

requests from the supplemental open season and considering whether to pursue the proposed McNary-John Day project.

B. COORDINATED REGULATION ACROSS STATE JURISDICTIONS

1. PacifiCorp Multi-State Process for state Jurisdictional Utilities

PacifiCorp operates a multi-jurisdictional utility system as an integrated whole. It has recently completed a process whereby most of its states (see footnote 5, Part I) have agreed to treat transmission investment and expenses, both existing and new, as joint-use facilities and to allocate costs based on relative, current use of the PacifiCorp system. Fixed costs are allocated based on relative contribution to peak monthly demand and variable costs and wheeling revenues are allocated based on relative energy consumption. New transmission investment is considered in the IRP process and evaluated against the other alternatives, including supply side alternatives, demand management, and including risk assessment with unknown future events, in determining least total system cost over the long-run.

2. Proposal for a MOU to Create a Standing Panel to Facilitate Collaboration on Multi-State Transmission Projects

A future multi-state Memorandum Of Understanding (MOU) could address the need to facilitate multi-state transmission planning in the interim period leading up to the operation of fully-functional RTOs in the western states. No one can predict when formal RTOs will be able to shepherd multi-state transmission efforts and the need to plan for projects cannot be deferred. The Western Governors' Association (WGA) has previously implemented an MOU between the western states and several federal agencies to facilitate the permitting and siting of multi-state transmission projects. However a second significant barrier to transmission development is not addressed by that MOU. The barrier is the uncertainty regarding the recovery of project costs and the allocation of the costs among affected producers and consumers in the western states.

The first portion of the MOU seeks to resolve the uncertainty regarding cost recovery and cost allocation of the RMATS phase I projects. A stipulation to this effect is feasible because the phase I additions affect a limited number of states and a limited number of entities within those states. Unfortunately, the more general problem of creating greater certainty relative to cost recovery and cost allocation of future multi-state transmission projects remains. As this document reflects, a great deal has been learned from the RMATS process and it would be inefficient to re-create these lessons with every new project. Part 3 of this report presented a taxonomy of transmission project types and corresponding ranges of cost recovery and allocation principles that may be applicable to each respective project type. The taxonomy and the principles are applicable to future projects and therefore may be leveraged to facilitate future multi-state agreements.

State policy makers need to understand how a given project affects them and how cost recovery and allocation proposals affect them. In order for policy makers to enter into

such negotiations, the policy makers need to have a level of understanding sufficient to give them comfort that their state's interests are being represented and protected. Applying the taxonomy and principles in this report to specific projects can give policy makers a basis for understanding their state's interest in a project and thus can give policy makers that level of comfort. Since multi-state transmission projects are expensive, complicated and infrequent there is a role for an intermediary to educate the states relative to their respective interests and to facilitate collaboration among state representative in reaching mutually beneficial solutions.

The second portion of the MOU seeks to create an informal institutional process that can assist state policy makers in collaborating on mutually beneficial multi-state projects. To that end the MOU seeks a commitment from western governors to support the creation of a mediation panel under the auspices of Western Interstate Energy Board (WIEB) that will hear multi-state transmission proposals from project proponents, will seek to educate state policy makers relative to their state's interests with respect to specific projects, and will seek to mediate collaborative solutions to the conflicts that arise among the states affected by the projects. WIEB would select members of CREPC to serve on the standing panel.

3. Southwest Power Pool Approach to Regional Cost Allocation

The Southwest Power Pool (SPP) developed a cost allocation proposal for transmission projects pursuant to a FERC Order dated February 10, 2004. The SSP formed a Cost Allocation Working Group (CAWG) to develop alternative proposals, drafted a working paper, held symposiums for members and interested parties, and coordinated discussions with the Regional State Committee (RSC). This section summarizes key elements of the SPP's cost allocation proposal.

The SPP proposal organizes transmission projects into four groups: (1) Base Funded Upgrades; (2) Economic Upgrades; (3) Requested Upgrade; and (4) Generator Interconnection Upgrades.

Base Funded (also called Base Plan) Upgrades can be thought of as those kinds of upgrades required for reliability of the overall grid. SPP is responsible for identification of these upgrades in its biennial planning process. Base Plan Upgrade costs are allocated on a combined region-wide and zonal basis in two steps. First, 33% of the costs are allocated across the entire region in SPP's "region wide rate." The remaining 66% of the costs are allocated using the SPP incremental MW Mile approach to identify zones that benefit from the upgrade. This scheme is subject to review every 5 years.

The SPP proposal contains a safe harbor provision for network upgrade costs subject to three conditions. First, a proposed project must have firm a commitment to pay its costs for at least 5 years to be eligible to be included in base plan funding. Second, a project cannot be based on providing more than 125% of peak load, unless approved by SPP. Third, project costs must be less than \$180,000/MW. If the upgrade costs exceed this

amount, the transmission customer must seek a waiver to have additional costs eligible for base plan funding.

Economic Upgrades are projects that are not required in the SPP Base Plan (i.e. not reliability related), but which may provide economic benefits while displacing Base Plan Upgrade projects. Transmission customers or SPP may propose Economic Upgrades. Project Sponsors would fund these projects and identify beneficiaries. If the project displaces the need for Base Plan Upgrades, that portion of the cost would get Base Plan cost recovery. Project Sponsors receive revenue credits up to the amount of the Economic Upgrade project costs that they fund directly (net of any Base Plan Avoided Costs).

Requested Upgrades are projects made in connection with routine transmission service requests made under SPP's Open Access Transmission Tariff (OATT). These costs are recovered in the context of those services and are not part of the new cost allocation scheme.

Generation Interconnection Upgrades are additions and upgrades beyond the first point of interconnection necessary to interconnect a generator, a merchant transmission facility or a load safely and reliably to the SPP transmission system. These costs are recovered under SPP's implementation of FERC Order 2003-A.

The SPP cost allocation proposal has not yet been formally adopted or implemented and will likely face many implementation challenges, especially in the project planning area and in the economic benefit analyses that must be done.

C. RENEWABLE TRUNK LINE PROPOSAL: TEHACHAPI

The Tehachapi area is California's largest potential wind resource. It currently has approximately 645 MW of wind capacity connected to the grid through two existing transmission lines – SCE's Antelope-Bailey 66 kV line and the independently owned Sagebrush 230 kV radial transmission line. The total wind capacity potential at Tehachapi is about 4,500 MW.

California has two renewable energy goals, as set forth in SB 1078 (20% of electricity sales by 2017) and the Energy Action Plan²¹ (20% of electricity sales by 2010). Both of these goals are centered on the installation of 4,060 MW of new wind capacity in the Tehachapi area.

The Antelope-Bailey line is currently fully loaded and, as of June, 2004 approximately 420 MW of new wind capacity had successfully bid for CEC New Renewable Resources Account awards, but are awaiting the construction of new transmission. In July 2004, the

²¹ The Energy Action Plan is a plan adopted in May 2003 by the CPUC, California Energy Commission (CEC) and the California Power and Conservation Financing Authority.

California ISO (CAISO) had identified approximately 700 MW of new wind to be built by PPM Energy, Inc.²²

Southern California Edison Company (SCE) has developed a phased Tehachapi transmission plan which provides for the construction of a 500 kW capable line, to be initially operated at 230 kV. Overall the upgrades would occur in at least three steps. Total cost of the full upgrades as proposed by SCE would be \$1.9 billion.

The fundamental problem from the CPUC's perspective (and presumably the perspective of many other stakeholders including wind developers) is that previously constructed transmission in the Tehachapi area has been based on small incremental transmission additions, designed and sized to meet the needs of each new wind project. Given a perceived need to develop Tehachapi into a fully mature resource with an installed capacity in the range of 4,000 MW, a more comprehensive, long-range view was needed.

On the other hand, the lead utility that would presumably build and own the new transmission facilities, Southern California Edison (SCE), resisted committing to construct the full-sized transmission expansion to meet the capacity potential of Tehachapi. SCE was unwilling to assume the risk of building the transmission lines out of fear that wind generators may not actually construct the new generating facilities that would utilize the transmission line. In short, the relevant parties were in a stalemate with wind developers arguing "build it and we will come" versus the SCE and CAISO position that "we're not counting those chickens until they hatch."

On December 1, 2004, SCE proposed the concept of a "renewable resource trunk line" as a solution to the Tehachapi stalemate. SCE is preparing to file for a declaratory ruling from FERC that would recognize and establish a policy precedent for this proposal. The proposal acknowledges that renewable resources like wind are geographically concentrated and such generators do not have the flexibility to locate like traditional fossil fuel generators. To meet these special circumstances, transmission providers would be given special rules to build a large trunk line to areas with recognized wind resources that would be capable of expanding capacity prior to the actual building of the generation capacity. The transmission providers would be given special abandonment rules to protect against the threat that wind developers fail to build the expected generating capacity that would provide the financial support for the transmission line investment.

This proposal is a new idea in the preliminary stage and will certainly evolve over time with new details and future FERC consideration. At this stage, it appears to offer a reasonable approach to break the stalemate over selected transmission expansion opportunities linked to wind resources.

²² PPM is a ScottishPower company, formerly known as PacifiCorp Power Marketing.

D. DETERMINING COST RESPONSIBILITY IN ADVANCE

Uncertainty about recovering costs poses a potential disincentive to transmission expansion investments. Policy changes that reduce cost allocation uncertainty for investors could address this problem.

In some states, the initial review and approval of the CPUN establishes conditions that a high probability that regulators will subsequently approve costs to the rate base after the project is built. Additionally, the IRP planning process provides a foundation of support to ensure a favorable future cost recovery decision.

In Wyoming, the Public Service Commission has authority to predetermine aspects of the cost recovery for a transmission project prior to its construction. The legal precedent was established in a case involving Washington Public Power Supply System. *Pacific Power & Light v. Public Service Commission*, 1984 WY 19, 677 P.2d 799 (Wyo. 1984). The Commission denied recovery for three abandoned nuclear power plant construction projects and was sustained on appeal by the Wyoming Supreme Court (the United States Supreme Court denied certiorari). The Commission was upheld because, among other reasons, the projects never became “property” which could be “used or useful” for retail public utilities serving the public in the state. The Court said, however, that the Commission could give consideration to the risk which consumers should bear with respect to an as yet unbuilt project. Thereby, the Commission could evaluate and accept or reject risk and cost responsibility on the public’s behalf, in whole or in part. The Court found that W.S. § 37-2-122(a) would allow such a predetermination as a consideration of the “other values of the * * * system, business * * * of the public utility.” *Pacific Power*, 1984 WY 19, 677 P.2d at 808. It can be used to determine costs to be borne in case of project failure as well as success.

“The percentage of the investment attributable to the Wyoming operation can be ascertained. All to be done before the fact of success or failure is known. As noted, this consideration and resulting decision will affect a ‘management’ aspect within ‘regulation,’ but it is the type of regulation necessary and proper for the exercise of the power and duties of the PSC.” *Id.* at 808-809.

This predetermination option has not been used since its discussion by the Court. Commission orders approving natural gas and electric utility securities contain standard language stating that the securities authorization should not be misconstrued as an evaluation of the risk that consumers should bear in the future.²³

²³ W.S. § 37-2-122 states:

“(a) In determining what are just and reasonable rates the commission may take into consideration availability or reliability of service, depreciation of plant, technological obsolescence of equipment, expense of operation, physical and other values of the plant, system, business and properties of the public utility whose rates are under consideration.

“(b) If, upon hearing and investigation, any service or service regulation of any public utility shall be found by the commission to be unjustly discriminatory or unduly preferential, or any

E. STATE TRANSMISSION INFRASTRUCTURE AUTHORITIES

Wyoming created the Wyoming Infrastructure Authority (WIA) as a quasi-government entity designed to stimulate the improvement of transmission capacity in Wyoming and the west. The enacting legislation vested the WIA with broad powers to plan, finance, construct, develop, acquire, own, maintain and operate” inside and outside of Wyoming, property and facilities. W.S. § 37-5-304.

Additionally, the WIA assumed certain powers that created a unique relationship with the Wyoming PSC. The WIA can establish rates and tariffs for its facilities and the services they provide after consultation with the PSC but the PSC may not set those rates. The WIA is specifically not under the jurisdiction of the PSC. W.S. § 37-5-307.

The WIA may issue revenue bonds or other obligations in principal amount of up to \$1 billion for projects it does not own but “which shall be located at least partially within Wyoming.” The amount of bonds it can issue for projects in which it has an ownership interest is not limited. The bonds must be backed up by “contracts sufficient to justify the issuance of bonds.”

The revenue bonds are payable from pledged revenues “from the operation of the project financed, by a first mortgage on the facilities, by guarantees and pledges of the entity owning the project or of the parent corporation owning said entity or by any combination thereof or other security as may be determined by the authority to be reasonable and prudent. The guarantees and pledges shall be no less favorable to the authority than those granted other lenders of the same class.” W.S. § 37-5-404(a). The WIA may hedge, insure and otherwise lower the cost of borrowing.

The WIA has prompted other states to consider developing similar infrastructure authorities for transmission. In Montana, legislation has been introduced in the state legislature to create an infrastructure authority on the Wyoming model. In New Mexico, Governor Richardson proposed new policies to promote new transmission to tap New Mexico’s wind resources. One feature of the New Mexico proposal is an infrastructure authority.

service or facility shall be found to be inadequate or unsafe, or any service regulation shall be found to be unjust or unreasonable, or any service, facility or service regulation shall be found otherwise in any respect to be in violation of any provisions of this act, the commission may prescribe and order substituted therefor such service, facility or service regulation, as it shall determine to be adequate and safe, or just and reasonable, as the case may be and otherwise in compliance with the provisions of this act, including any provisions concerning the availability or reliability of service. It shall be the duty of the public utility to comply with and conform to such determination and order of the commission.”

CHAPTER VI: NEXT STEPS

The TREG group and this document are not yet prepared to offer final recommendations for a vote. We are now at the point where we need feedback so that we can move forward with formal proposals at the fall meeting and perhaps have an MOU for consideration of the Governors at the October WGA meeting. We have three specific areas where we require input and a discussion of each along with some broad questions follows.

Analysis of Transmission Regulation

This paper is intended to offer decision-makers in the western states:

- A description of how transmission planning, siting and permitting processes have worked in the recent past and a description of how it is happening today;
- A set of cost allocation principles that may be used to think through what might constitute a fair allocation of costs for a given transmission project;
- A taxonomy of transmission project cost types and a matrix of transmission project scenarios that seek to correlate different hypothetical transmission projects to siting issues, cost recovery issues, efficiency issues and regional coordination issues that are raised by the given project; and
- A discussion of alternative approaches used to build transmission in related industries and in different parts of the country.

The specific questions we would like you to consider relative to the document as a whole for discussion at the upcoming CREPC meeting are:

- Are the chapters describing the planning, siting and permitting processes clear and useful? Is the information accurate and adequate relative to the states that are already covered by the document? Are there information gaps in these chapters that need to be filled?
- Should this be turned into a west wide document reflecting all western states? If it should be expanded to include more states, what information should be collected from the remaining states?
- If this should not be turned into a west wide document, are there any specific information gaps that need to be filled to make the current document useful for our discussion in the fall?
- Do the principles and matrix section need improvement? What suggestions do you have for making these sections better?

The Principles and RMATS

We are specifically interested in whether the cost allocation principles could be useful in reducing the cost recovery risk of potential RMATS projects. So we would ask RMATS stakeholders:

- Do the cost allocation principles meet the short term goal of mitigating cost recovery uncertainty?
- Do the cost allocation principles need to be supplemented with more specific cost allocation proposals in order to meet the need of potential investors/developers?

The Principles and a Potential MOU

We are also interested in whether the principles could be useful for the western states in improving project certainty. So we would ask CREPC:

- Would it improve project certainty if there was an MOU among the western states whereby the states commit themselves to consider the cost allocation principles as they evaluate inter-state transmission projects?
- Should the MOU include a commitment by a CREPC subcommittee to create a multi-state forum where potential project developers could discuss the principles and their meaning relative to cost allocation and recovery with respect to a proposed project?
- If CREPC should not create such a forum, how could states and project developers make the principles useful?
- If an MOU committing to a set of cost allocation principles is not useful, how can we use the information we have gathered to date to improve upon multi-state transmission project certainty?