

A Discussion of FERC Authority and Transmission Ratemaking (For the RMATS Cost Allocation/Cost Recovery Evaluation Team)

The Commission's Statutory Authority¹

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 not over facilities (1) used for the generation of electric energy, (2) used in local distribution, or (3) for the transmission of electric energy consumed 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 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

¹ 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.

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:²

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.³ The transmission revenue requirement is divided by the CP divisor applicable 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 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

² This summary paper will not endeavor into the details of the case precedent surrounding the application of each cost-of-service component.

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

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 to 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 are 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 TransConnect⁴, 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 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

⁴ 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.

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.⁵

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 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 formulaic, 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.

Midwest Independent System Operator

Under the current tariff, the Midwest ISO develops a Transmission Expansion Plan for all network facilities above 100 kV over its planning horizon. The TEP includes both reliability-based and commercially-beneficial (economic) projects.

Network upgrades required to be constructed pursuant to the TEP are proposed to be allocated among all license plate pricing zones in proportion to the zonal loads (i.e., postage-stamp treatment). The costs of all upgrades not included in the TEP are rolled into the rate for the license plate pricing zone where

⁵ 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.

the facility is located. The costs of network upgrades needed to satisfy transmission service requests may be rolled into the transmission owners' license plate rates. However, until such costs are included in rates, the transmission owner will charge the requesting customer a monthly fixed charge rate for the facilities.⁶

The costs of network upgrades required for generator interconnection service are paid upfront by the interconnection service customer but the customer receives credits for these payments when it takes transmission delivery service. The costs of facilities that solely benefit the transmission delivery service or interconnection service customer, *i.e.*, non-network facilities, are directly assigned to the transmission or interconnection service customer.

ISO New England

New England's Regional Transmission Expansion Planning (RTEP) identifies system needs through input from the stakeholder Transmission Expansion Advisory Committee, which includes participation not only by ISO-New England and market participants, but also representatives from state regulators, public interest groups and retail customers. Market participants may propose resources (generation, demand-side projects, and transmission) in response to the system needs identified through the RTEP. If market responses have not addressed identified system needs, then the ISO identifies needed transmission projects.

The ISO evaluates whether the costs of the identified projects will be rolled into the regional network rate or be paid by participant funding. The costs of upgrades deemed needed for reliability and those that provide a net economic benefit to New England as a whole will be rolled into the regional transmission rate paid by all network customers. In addition, the costs of facilities that are rated at or above 115 kV and are looped facilities (allowing for the free flow of power on the regional system) will also be rolled into the regional transmission rate.

The costs of generator interconnections, elective transmission upgrades, merchant transmission facilities, and upgrades that do not meet the ISO's reliability or economic criteria are borne by the entities that request, require or voluntarily undertake the building of such transmission. Individual participants may also have to fund a portion of the costs of a project that is rolled into rates if the ISO determines that some aspects of the project do not produce regional benefits, such as burying transmission lines. Alternatives by parties involved in the ISO New England expansion and rates process offered an alternative that would call for all transmission-plan approved transmission facilities have 25% of the project costs allocated regionally (socialized to all transmission load) and the remaining 75% allocated to the locally-based primary beneficiaries. When no primary beneficiaries could be identified, 100% of project costs would be allocated regionally.

The Commission found the ISO New England proposal reasonable and explained that the key to the project cost treatment is to develop a mechanism that allocates the costs of transmission upgrades in an objective, non-discriminatory manner and respects the principle of cost causation. The Commission also emphasized that it will give deference to regional choices, particularly the choices of regional state committees, on how to allocate costs of transmission expansions. In the New England process, while not all the states agreed to the proposed approach, there was a majority consensus (78%) of the NEPOOL stakeholders, including state representatives from Massachusetts and Connecticut supporting the proposal.

New York ISO

The New York ISO does not have a comprehensive transmission planning process with a cost allocation method. It is now in the process of developing one to comply with FERC Order No. 2000.

Transmission planning is now performed pursuant to an Annual Transmission Reliability Assessment (Reliability Assessment), conducted by the NYISO staff and transmission owners to identify the system upgrade facilities that each transmission owner will need to install to comply with applicable

⁶ The Commission is not aware of any facilities built pursuant to these tariff provisions.

reliability requirements, and reliably meet the load growth and changes in load pattern projected for its geographic service area. Transmission owners fund the costs of modifications to the existing transmission system that are required to maintain system reliability with those costs then rolled into license plate rates.

The Reliability Assessment and an Annual Transmission Baseline Assessment are used as a basis to allocate the cost of generator interconnections between developers and transmission owners. Each developer is responsible for the facilities constructed solely to physically attach its project to the grid. Each developer is also responsible for the cost of any interconnection facilities required to maintain reliability that would not be required but for the project. If a developer's project reduces the need for facilities that otherwise would be needed, the cost reductions are netted against the developer's cost responsibility. The net cost and cost reduction impact of a developer's project is determined by comparing the results of annual transmission system assessments and interconnection impact studies that are conducted or approved by the ISO.

PJM

PJM has historically focused on the need for reliability driven upgrades in its Regional Transmission Expansion Plan (RTEP). PJM generally uses NERC and MAAC criteria and obligates the transmission owners to supply staff and data to support a regional analysis. The planning process provides for the participation of all interested stakeholders and for coordination with neighboring control areas. Cost responsibility for reliability upgrades is allocated to transmission zones based on their contribution to the need for the upgrade, *i.e.*, the reliability criteria violation. The allocated shares of upgrade costs are then recovered through individual license plate rates.

At the Commission's direction, PJM also has adopted a process for identifying upgrades that are needed to support competition, or economic driven upgrades. PJM will first identify constraints in the system where congestion is chronic and "unhedgeable." For constrained facilities, PJM will calculate hourly congestion costs associated with each constraint and also calculate cumulative monthly congestion costs. When the cumulative monthly congestion costs on a facility reach a specific threshold amount (yet to be determined), PJM will post a notice on its website and begin to assess if such congestion can be hedged by FTRs or other means, and whether such congestion is the result of recurring or non-recurring causes of transmission constraints. If PJM determines that the congestion is unhedgeable, it will post a notice of the need for relief, which will start a one-year period for market solutions to be proposed. Market solutions may include generation, demand response, or merchant transmission resources. At the start of the one-year period, PJM must make known how the costs of any congestion-reducing project will be allocated so that parties may make rational business decisions.

If a market solution is proposed and adopted, the sponsor of the proposal is responsible for its costs. If a market solution is not proposed within the one-year period, PJM will identify the upgrade or expansion that is needed to alleviate the congestion, subject to satisfying a cost-benefit analysis and stakeholder input. PJM will then direct one or more transmission owners to construct the needed facilities. The costs of such directed facilities will be recovered by a per-MWh "transmission enhancement charge" levied on market participants that PJM determines will benefit by the upgrade or expansion. PJM will initially apply such charges on a zonal basis but will consider the feasibility of doing so to sub-zones based on the contribution of specific groups of market participants to the need for the upgrades and the benefits derived by those groups.

PJM evaluates generation interconnection requests in six month cycles and the transmission facilities required to accommodate the interconnection are incorporated into the RTEP. The upgrades that an interconnecting generator must pay for depends on whether the generator wants to sell only energy into the PJM markets or whether it also be able to sell capacity. If the generator wants to sell only energy, then it is responsible for the costs of attachment facilities necessary to accommodate its interconnection request as well as the costs of the minimum amount of local and network upgrades necessary to accommodate its interconnection request that would not have been incurred under PJM's RTEP "but for" such interconnection request. If PJM determines that, in the context of the RTEP, it is more beneficial to construct upgrades in excess of the minimum required to accommodate an interconnection request, the

interconnection customer is responsible only for the costs of the minimum upgrades necessary for its interconnection request.⁷ The remaining costs are borne by transmission owners and, if they cannot agree on cost responsibility, costs are allocated among transmission owners in proportion to the load in each PJM zone. If the interconnecting generator wants to be able to be a capacity resource in the PJM markets, then it must also pay for the transmission upgrades needed to enable the generation to be deliverable anywhere within PJM.⁸

There are also procedures and cost responsibility protocols for interconnecting new and expanded merchant transmission facilities. Merchant network upgrades to existing facilities must be conveyed at no cost to the transmission owner to whose facilities the upgrades are attached. The transmission owner will operate and maintain the facilities at the expense of the merchant. The merchant developer will receive all interconnection-related revenue-producing rights (such as auction revenue rights, incremental transfer capability rights and incremental deliverability rights) that are created by the merchant network upgrade. The costs of subsequent upgrades or expansions of merchant transmission facilities that are needed due to reliability concerns or to accommodate future transmission service requests or new interconnections will be allocated among transmission owners in proportion to the load in each zone

California Independent System Operator

The California ISO plans and addresses cost responsibility for the high voltage transmission facilities (above 200 kV) that are under the ISO's operational control. The ISO, a participating transmission owner or any market participant may suggest the need for and propose a transmission system addition. Every year each participating transmission owner develops a transmission expansion plan for its service area covering a minimum five-year planning horizon. The transmission owner coordinates with the ISO and other market participants in developing the plan. A transmission addition or upgrade is considered to be needed where it would promote economic efficiency or maintain system reliability. Disputes over whether an economic proposal should go forward are settled in an ISO dispute resolution process. Reliability projects must clear the coordinated planning processes of the Western Electricity Coordinating Council.

Regardless of who proposes a project, a participating transmission owner is obligated to construct and own all transmission additions and upgrades within its service area subject to obtaining all necessary approvals and having a cost recovery mechanism consistent with the discussion below. If either an economic or reliability driven project is determined by the ISO to be needed, the costs may be borne by the participating transmission owner and then recovered through the ISO-wide high voltage access charge. A project sponsor may instead commit to pay the full cost of an addition or upgrade, in which case the sponsor is entitled to receive a share of wheeling revenues, FTR auction revenues, and congestion revenues associated with its project. The project sponsor's share is the percentage change in transfer capability that results from the project.⁹ This revenue entitlement does not apply if the sponsor recovers its project's costs in a direct payment from a transmission owner or through the access charge.

Interconnection customers are responsible for the costs of reliability driven upgrades if those upgrades are not already included in ISO grid expansion plan. Interconnection customers may also sponsor delivery upgrades (beyond the level of reliability upgrades) and the cost recovery of those would be in accordance with the above discussion. If an interconnection customer elects not to fund transmission upgrades, and if the ISO finds that the generation is needed, the ISO may direct the applicable participating

⁷ The transmission interconnection customer will have the right of first refusal to pay for any or all of the upgrades in addition to the minimum, and to hold all incremental Auction Revenue Rights and/or incremental Available Transfer Capability Rights associated with the additional upgrades for which it agrees to pay.

⁸ Because of the deliverability requirement for generators to be a capacity resource, many of the transmission upgrades within PJM have been paid for by new generators.

⁹ Specifically, the project sponsor's share is equal to quotient of the new rating of the upgraded facilities minus the previous rating divided by the new rating.

transmission owner to pay for the upgrade and the cost responsibility would be as discussed above regarding ISO directed projects.¹⁰

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).¹¹

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.

¹⁰ See Amendment No. 39 to the CAISO Tariff.

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