ATTACHMENT 13

Comments on the California ISO's Transmission Expansion Assessment Methodology (TEAM)

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1. Introduction

Transmission network expansions can increase the competitiveness of wholesale electricity markets by expanding the size of the geographic market that each supplier competes in. They can also save generation capital and fuel costs by increasing the number of hours of the year that cheaper generation is able to displace more expensive sources. Finally, transmission expansions can improve system reliability by lowering the probability and severity of service interruptions. It is important to recognize that virtually all transmission upgrades, including those undertaken primarily for reliability reasons, have significant economic impacts on some, if not all, users of the network. A better understanding of these impacts will increase the cost-effectiveness of California's transmission planning process.

Efficient and socially beneficial development of California's transmission network requires a comprehensive framework for quantifying the expected costs and benefits of specific transmission expansion proposals. Without such a framework, California's electricity market will continue be undermined by a transmission network that was built to serve a vertically-integrated geographic monopoly market structure that no longer exists. The California Public Utilities Commission (CPUC) has therefore asked the California ISO to prepare and propose such a methodological framework. Our understanding is that the methodology is to be applied to the many transmission upgrades whose benefits primarily flow from enhancing competition and lowering system wide generation costs. For such upgrades, it is assumed that resource adequacy requirements will ensure that the probability of interruption of supply satisfies the required engineering reliability criteria. A benefits assessment framework is necessary to determine whether the expected discounted present value of the economic benefits of a proposed upgrade exceeds the expected costs of this upgrade. Moreover, the major value of a transmission upgrade is as an insurance policy against extreme market outcomes caused by such factors as hydrologic conditions, input fuel prices, demand growth and new generation capacity investments. A complete understanding of the future system conditions that result in significant net benefits for a proposed upgrade will reduce the likelihood that these extreme system conditions adversely impact California consumers.

The Market Surveillance Committee (MSC) has been asked to comment on the California ISO's proposed Transmission Expansion Assessment Methodology (TEAM). This methodology is intended to provide a robust framework for conducting a net present value analysis of proposed transmission upgrades for the California ISO control area. Computing this net present value requires estimates of the cost of the upgrade and the expected benefits stream associated with the upgrade. This expected benefits stream should be broken down by the relevant stakeholder groups—consumers, suppliers, and transmission owners—and by geographic service territories of the load-serving entities in and outside of California. Such a breakdown enables the relevant decision-makers to determine whether those who will bear the cost of the upgrade, which may vary from one upgrade proposal to another, are expected to benefit from the upgrade.

The MSC strongly supports the adoption of a comprehensive transmission benefits assessment methodology for the California market. A number of recent events in the California market emphasize the need for a forward-looking comprehensive transmission benefits assessment methodology. Two notable examples are the Miguel-Imperial Valley transmission congestion and the potential liability to California consumers associated with the seller's choice forward contracts purchased by the California Department of Water Resources (CDWR). The application of a forward-looking economic benefits assessment methodology for transmission upgrades could have significantly reduced the adverse impacts of both these events to California consumers.

There are five key principles underlying the California ISO's Transmission Benefit Assessment Methodology. This opinion first summarizes each of these key principles and then describes why each one is a necessary component of a robust transmission benefit assessment methodology. We then discuss how the ISO's proposed methodology addresses each of these key principles. Finally, we suggest potential refinements of the methodology for the ISO to consider in future applications. We then summarize public comments the Market Surveillance Committee received from stakeholders in preparing this opinion.

2. The Five Key Principles

The ISO's methodology is based on the five key principles: (1) benefits framework, (2) network representation, (3) market prices, (4) uncertainty, and (5) resource substitution. The benefits framework is a consistent structure for summarizing the benefits, costs, and risks regarding the proposed transmission upgrade. Network representation emphasizes the importance of accurately modeling the actual transmission network and locational pricing process used by the wholesale market to assess the benefits of a proposed transmission upgrade. Market prices denotes the fact that market participant bids, rather than production costs, must be modeled because one aspect of the expected benefits of a transmission upgrade is to increase the number of independent suppliers able to compete to supply power at a given location in the transmission network. Uncertainty accounts for the fact that a major benefit of transmission upgrades is a greater quantity and diversity of available supply at certain locations in the network as insurance against uncertain future outcomes, such as hydroelectric energy availability, input fuel price uncertainty, generation outages, and extreme weather conditions. Resource substitution denotes the fact that the value of a proposed upgrade is directly dependent on the cost of resources or solutions that could be implemented in lieu of the upgrade.

2.1. Benefits Framework

A transmission network expansion can create enormous transfers of wealth between market participants. An owner of a high cost generation unit located close to a load center may find that this unit is no longer financially viable as a result of a transmission upgrade. Consequently, the methodology must make a clear distinction between wealth transfers among market participants and the net benefits to each market participant associated with a transmission upgrade. For this reason, an important component of any transmission evaluation methodology is the ability to parse out the benefits of any proposed upgrade to all relevant stakeholder groups for any conceivable set of system conditions.

One strength of the ISO's methodology is the detail that it provides in quantifying the benefits to specific markets participants by type and geographic location. For example, the ISO is able to compute the benefits to consumers, producers and the transmission owners both in the aggregate and for specific parts of California and rest of the Western Electricity Coordinating Council (WECC). Such a detailed breakdown is important to both market participants and the relevant decision-making authority, because a necessary step in any transmission expansion process is determining whether the entities required to pay for an upgrade expect to receive sufficient benefits from it to justify going forward with the expansion.

There is a significant amount of debate among stakeholder groups as to what is the relevant expected benefits measure to compare to the estimated costs of the transmission upgrade. Under the former vertically-integrated monopoly regime, the total production cost savings arising from the upgrade was assumed to represent its economic benefits. If the vertically integrated utility expected to be able to serve its total load obligations with lower cost power as a result of the upgrade and the present value of these expected wholesale energy cost savings was less than the estimated cost of the upgrade, typically the vertically integrated monopoly was justified on economic grounds to undertake the transmission upgrade.

In the wholesale market regime, this decision-making process is complicated by the fact that consumers do not pay total production costs for their electricity. Instead, they pay a market price. The value of a transmission expansion in the wholesale market regime is derived from the increased ability it provides to substitute lower-priced energy for higher-priced energy, instead of low cost energy for high cost energy. Thus, there is an additional reason that energy at certain locations in the network may be more or less expensive: the geographic variation in the ability of suppliers to exercise unilateral market power and raise the wholesale price above the marginal cost of supplying electricity at that location in the network.

Because the value of a transmission expansion in the wholesale market regime is determined by differences in wholesale electricity prices across locations in the transmission network, policy makers may not want to consider certain causes of locational price differences in computing the benefits of transmission upgrades. For example, to the extent that a transmission upgrade reduces the ability of a supplier to exercise market power and artificially increase the price that consumers pay for wholesale electricity at certain locations in the network, the decision-maker may not want to count these reduced market power profits as a benefit of this transmission upgrade, unless they also reduce average wholesale electricity prices.

A major determinant of what benefits sources should be included in the benefits measure is the decision-maker's assumption about which market participants own the transmission network. For example, if the assumption is that California consumers own the transmission network in California, then relevant benefit criteria should be total benefits to California consumers. In this instance, the relevant benefit measure should be reduction in total wholesale energy and ancillary service payments by consumers less any reduction in congestion revenues rights (CRR) payments that result from upgrade.[1] If consumers are assumed to own the transmission network, then this benefit measure is consistent with the following logic: If the discounted present value of the reduction in wholesale energy and ancillary services payments (net of congestion revenue rights payments received by consumers) exceeds the cost of the transmission upgrade, then consumers would find it in the their joint interest to undertake the transmission upgrade. This ownership assumption would not count increases in the extent of market power that suppliers are able to exercise as a result of the transmission upgrade in the benefits associated with upgrade, nor would it count as a cost decreases in profits resulting from reductions in market power.

If the assumption that the decision-maker adopts is that both California consumers and suppliers own the transmission network, then the change in supplier profits (including any derived from exercise of market power) should also be included in the total benefits measure. Specifically, if (1) the reduction in wholesale energy and ancillary services payments plus the net increase in CRR revenues to California consumers plus (2) the increase in wholesale energy profits to California suppliers plus the net increase in CRRs revenues to California producers exceeds the cost of the transmission expansion, then these market participants would find the transmission expansion jointly in their interest.

Finally, if the transmission network is assumed to be "owned" by all suppliers and consumers in the WECC, then the relevant benefits measure becomes the total production cost savings for the entire WECC associated with this transmission upgrade.

Because of the subjective nature of making a determination of which entity "owns" and therefore what is the appropriate measure of benefits associated with a given transmission upgrade, we do not have an opinion on which benefits measure should be used. Instead this decision should be made by the relevant regulatory authority that approves the funding and construction of the transmission facility. We do, however, note that benefits measures that do not assume the entire WECC "owns" the transmission network may result in a pattern of transmission expansions in California that benefits California consumers and/or producers at the expense of suppliers and consumers in the rest of the WECC. We also note that information about the distribution of benefits among market participants is also useful for identifying parties who can help pay for the upgrade. For instance, if it was decided that consumers own the grid

[1]To the extent that electricity demand is price-responsive, a benefit measure based on consumers surplus will diverge from one based solely on consumer payments. The ISO's proposed methodology can be readily modified to account for this difference.

but that producers will be the primary beneficiary of an upgrade, this would motivate a search for ways to have producers to contribute to the cost of the upgrade.

Similar logic applies to the choice of the discount rate used to convert future expected benefits flows into current period expected benefits flows, so that the total expected benefit flows over the life of the project can be compared to the current estimated cost of the project. Because of uncertainties associated with the appropriate cost of capital for a given transmission upgrade, we believe that the methodology should compute the present value of the net benefits for a range of discount rates.

2.2. Network Representation

Because the major driver of the benefits of a proposed transmission upgrade is the difference in electricity prices across locations in the transmission network, the market simulation algorithm used to set the locational prices in the transmission benefits assessment methodology must represent as accurately as possible the actual market prices that would result from the assumed system conditions and bids submitted by market participants. This implies that a methodology for comprehensive transmission benefits assessment must have the capability to represent transmission constraints that limit flows and dispatch and, thus, affect production costs and locational prices. Generally, these constraints take several forms:

- Kirchhoff's current and voltage laws, which cause flows to follow parallel paths;
- Limitations upon flows for single lines or other equipment (e.g., thermal limits for shorter lines and transformers and, for some longer lines, surge impedance loading limits); and
- Stability and voltage limits (often represented as nomograms) that restrict certain combinations of flows on different lines.

Ideally, the same transmission network model used to operate the system and set prices in the day-ahead, hour-ahead, and real-time markets should be used to determine locational prices for the purposes of computing the benefits of the transmission expansion. However, the present state of algorithms and computational technology means that it is impossible for the foreseeable future to run combined unit commitment and AC optimal power flow models for all hours in a planning horizon while considering a large combination of scenarios concerning load growth, fuel prices, hydrological conditions, generator and transmission outages, and other potential uncertainties about future system conditions.

Therefore, modeling compromises must be made that simplify aspects of the problem that are not crucial to evaluating transmission benefits. In general, it is impossible to say which aspects can always be safely simplified and which ones must always be represented in a more complex manner. However, we believe that, at a minimum, transmission benefits must be verified using a linearized (so-called "DC") load flow model of the high voltage network under a range of possible fuel, load, hydrological, and equipment availability conditions. Linearized DC models represent the parallel nature of power flows in a network while accounting for flow limitations for single components and nomograms.[2] Linearized DC models do not explicitly calculate VAR flows or voltage magnitudes, and so introduce some inaccuracies (e.g., derating component capacity to accommodate VAR flows or nomograms to approximate voltage constraints).[3]

An alternative modeling approach can be based on "transshipment" (also called "transportation" or "zonal") models, often involving aggregations of buses into zones and multiple circuits into single paths. There are several potential difficulties with such simplified representations. One is that such models usually disregard Kirchhoff's voltage law, thereby allowing power flows to be directed along preferred paths so that they bypass constraints that would otherwise be binding.[4] That is, they treat the transmission system as if it was a network of pipes with valves. If the network is strictly radial in form and there are no nomograms that restrict combinations of flows through different components, a transshipment model can be a sufficiently accurate representation of flows. However, in the more general case, by excluding nomograms and parallel flow restrictions, transshipment models artificially increase the feasible region of flows. This causes a downward bias in production costs and, thus, the benefits of transmission reinforcements. It is possible to attempt to correct for this bias by derating the capacity of individual lines, but unless the transmission system is radial, such corrections are *ad hoc* in nature and can even lead to upward biases in costs. For instance, a conservative approach might derate capacities so that each individual line flow never exceeds the minimum possible flow under any plausible configuration of injections in the network, or so that individual line flows are restricted to some percentile of observed flows. The result in that case can be too small of a feasible region for injections, thereby artificially inflating production costs. To illustrate these points, we present a simple example of a three-node network in an Appendix to this opinion.

Other difficulties with transshipment models arise because the process of aggregation can distort production costs and prices in a networked system. One type of aggregation is of buses into large zones. In that case, distortions can occur even if there are no binding constraints within a zone, because different buses within a zone will have different swing factors relative to binding constraints outside the zone. Such aggregation can hide within-zone price differences that will matter to some market participants (such as metered subsystems who do not pay a zonally averaged price, or generators). Further, there is no guarantee that a zonal price calculated by an

[2] Nomograms can be exactly represented in a linearized DC model if they can be represented as a set of inequalities that are affine functions of flows and injections. If a nomogram is nonlinear, but still defines a convex feasible region, then a set of affine inequalities can be defined to approximate the nomogram to any desired degree of accuracy. If a nomogram defines a nonconvex feasible region, then the accuracy of the linearized model depends on the magnitude of the nonconvexity. In the case of the SCIT nomogram, which is nonconvex, the degree of nonconvexity is not large.

[3] Experiments with large-scale transmission systems in ERCOT, the eastern interconnection, and the WECC confirm that linearized DC power transmission distribution factors generally do an excellent job of reproducing marginal transmission flows in full AC load flow models, although the match in the WECC is not quite as good as in other regions (see R. Baldick, "Variation of Distribution Factors With Loading", IEEE Transactions on Power Systems, 18(4), Nov. 2003, 1316-1323, and T.J. Overbye, X. Cheng, and Y. Sun, "A Comparison of the AC and DC Power Flow Models for LMP Calculations", 37th Hawaii International Conference on System Sciences, January 2004, Big Island, Hawaii).

[4] FACTS devices, such as phase shifters, enable flows in an AC network to be controlled to some extent; such devices, and constraints in their operation, can be represented in linearized DC load flow models.

aggregated model will closely approximate the load-weighted average locational price that would be derived by a full network model.

A second type of aggregation is of several constraints that might potentially limit flows on a path into a single constraint on path flow. For instance, there may be several capacity-limited lines in parallel, and in addition they may be in series with capacity-limited transformers or other substation equipment. Under certain assumptions, one of those many constraints may be identified as the limiting factor in a detailed load flow analysis, and an equivalent path rating might then be estimated for use in an aggregated transshipment model. However, variations in the distributions of loads and generation or changes in network configurations could change which constraint is binding. The transshipment model's path rating may then be incorrect (thus distorting estimates of production costs and prices), and the only way to know would be to repeat the detailed load flow analysis.

The difficulties that can arise when one tries to squeeze a network into the strait-jacket of a transshipment or radial model are amply indicated by the recent challenges faced by the ISO in managing Miguel-Imperial Valley congestion. It has become abundantly clear that a radial representation of network constraints is inadequate, and that locational marginal pricing based upon a full network model is required.

Therefore, we believe that any estimation of transmission benefits should rely upon a full network model, unless computational experiments under a representative range of cost and demand conditions show that little bias results from using a simpler transshipment model. If indeed there is little such bias, then a transshipment model may have significant computational advantages, allowing consideration of a more complete range of fuel price, demand, hydrological, and equipment outage scenarios. However, in the absence of a demonstration that insignificant bias results from network simplification, a full network model based upon, at a minimum, a linearized DC load flow should be adopted.

2.3. Modeling of Market Prices

The experience of the past six years in California has provided ample evidence that transmission constraints can enhance the ability market participants to exercise unilateral market power. For this reason, a transmission benefits methodology that is to be applied in the context of a restructured wholesale market must try to account for the impacts of a transmission upgrade on market power and therefore market prices. Despite the fact that modeling the impact of market power is extremely difficult and fraught with substantial uncertainties, its potential impact on the benefits of a transmission upgrade should not be ignored.

At the same time, it should be recognized that the interaction of transmission constraints and market prices is an extremely complicated process that is difficult to model. Over the last decade there has been quite a bit of research into methods for modeling imperfect competition in electricity networks and several approaches have been developed. Unfortunately, the process of vetting and empirically testing these approaches has just begun.

Techniques for modeling strategic behavior in transmission networks fall into two general categories: the simulation of oligopoly competition and the econometric estimation of relationships between various market elements and market prices or price-cost margins. The strength of the best oligopoly models is that they are based upon economic equilibrium concepts. While markets are almost certainly never in a true equilibrium, over time most all markets tend toward equilibrium states. While equilibrium models may not be a perfect descriptor for where we are, they are often quite informative about where we may be going in the future.

That said, oligopoly models that incorporate transmission network constraints can be very complex. This can both cloud the economic intuition provided by the models and reduce the value of the models because these complexities typically produce multiple equilibria or, as was often in the case of the London Economics model, no equilibrium at all. In order to solve models in a reasonable time, strong assumptions must be made about the firm behavior and their responses to the behavior of other firms.

Econometric techniques can follow a predictive approach, where relatively fewer assumptions are made about the functional form of the relationship between market factors such as the concentration of generation ownership or transmission capacity and market prices. This kind of analysis must still make some assumptions about the functional form relating the factors that predict market outcomes to the specific market outcome chosen, such as if the impacts of these predictive factors are additive or multiplicative. More structural econometric modeling techniques use an explicit economic theory to derive the relationship that forms the basis for the empirical analysis. However, if the econometric modeler feels that individual variables in an estimated statistical relationship should interact in a specific way and this restriction is imposed in the actual estimation, it will affect the parameter values estimated by the regression and, in turn, the estimated impact of the dependent variables on market outcomes.

The advantage of econometric approaches is that, by definition they are benchmarked to actual relationships between these observable factors and market outcomes. The coefficients defining these relationships are based upon an econometric fit to historical data. This is a valuable aspect of this approach, and one can often take comfort in the fact that the estimated relationships make empirical sense. It therefore follows that the relative strength of econometric models will depend upon the quantity and quality of data that are available to feed into the models. Two potential risks are relevant here. First, the lack of current data requires making assumptions about the relationships between variables. Second, historic predictive relationships may not reflect future predictive relationships because of changes in the incentives of firms or the structure of the market.

Another consequence of the shortcomings of currently available data is the fact that it is difficult to estimate econometrically unit or even firm-specific bid mark-ups. Thus assumptions must be made about how to translate the estimated market-wide price-cost markups into unit specific bid mark-ups. For example, the ISO currently assumes that bid-cost markups are scaled relative to the size of the strategic firm's portfolio within the zone. By contrast, some oligopoly simulation models are able to derive unit-specific output levels for strategic generators.[5] Depending on how the market evolves, more data may become available on the unit-specific bids of firms and econometric specifications can be refined to estimate mark-ups at the unit level.

Thus although the relationships estimated in the current proposal are grounded in empirical data, important assumptions had to be made either because of the lack of data or the lack of variation in key data. In particular, periodic variations in the available capacity on critical California transmission paths do not explicitly appear in the ISO's empirical estimates. So we cannot empirically observe, for example, how margins would change with a variation in the available *capacity* of Path 26, although we can observe how margins change with the actual *flows* over the line. The relationship between flows and transmission capacity is instead imputed from the functional form of the regression model and the results of the production-cost simulation. This fact implies that predictions of theoretical models of oligopoly equilibria imply relationships between transmission capacity and imports that are not always consistent with those predicted by the ISO model.

There are many uncertainties and ambiguities in predicting mark-ups; this is a fact of life that must be recognized and dealt with in transmission benefits assessment. A benefits methodology that uses a single set of predicted mark-ups or single mark-up prediction methodology will distort decisions. We believe that the most reasonable course is to develop alternative plausible scenarios of mark-ups and then explore their implications for market prices and upgrade benefits. These alternative scenarios might be derived from simulation models under alternative assumptions, or from empirical relationships based on alternative data sets or specifications. It is important to recognize that no single set of predictions is likely to be correct. However, as the experience of June 2000 to June 2001 in the California market emphasizes, the impact on the exercise of unilateral market power is an extremely important component of an expected benefits assessment of a proposed transmission upgrade. In general, the proposed TEAM methodology can accommodate different sets of mark-ups, and this capability is illustrated by the sample Path 26 analysis.

In summary, there are several general approaches to modeling the economic behavior of generation firms operating within constrained transmission networks. Each approach has relative strengths and weaknesses. The adoption of any one of them for a particular study may defensible, but at the same time subject to criticism. The RSI approach adopted by the ISO, for example, utilizes actual empirical relationships but also relies upon strong assumptions about the relationships between key variables. The state of knowledge in this area is rapidly expanding, and we urge continued exploration into the relative effectiveness of the various approaches. As further data become available, we will be better able to both improve econometric estimates of these relationships and to calibrate oligopoly simulation approaches to real world outcomes. The

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[5] S. Borenstein and J. Bushnell (1999) "An Empirical Analysis of the Potential for Market Power in California's Electricity Market." Journal of Industrial Economics, Vol 47, No. 3, September, present oligopoly simulation model of the California electricity market. An example of an oligopoly simulation considering network constraints and unit-specific decisions is B. Hobbs and F. Rijkers (2004), "Modeling Strategic Generator Behavior with Conjectured Transmission Price Responses in a Mixed Transmission Pricing System: Formulation and Application", IEEE Transactions on Power Systems, 19(2), May.

benefits methodology should be designed to allow convenient consideration of alternative scenarios of mark-ups and market behavior.

A major area for future research on this topic is benchmarking the method used to construct markups for the benefits assessment methodology to historical market outcomes. For example, the ISO should explore the extent to which the RSI methodology applied to the time period 2002-2004 yields predicted markups close to the actual markups observed. Alternatively, if a simulation model is used to compute predicted markups, the ISO could explore the extent to which this model was able to replicate actual market outcomes when applied to demand and input price data observed during that time period.

2.4. Modeling Uncertainty

Because future system conditions are the major driver of the benefits associated with a transmission upgrade, there is an enormous amount of uncertainty associated with any given benefits assessment. In particular, virtually any transmission upgrade can have positive net benefits for a plausible set of future system conditions. Adequately capturing the range of plausible values for all of the drivers of locational prices differences is crucial to obtaining credible expected benefits estimates.

The events of June 2000 to June 2001 provide a vivid illustration of the extent to which extreme events can drive the benefits of a transmission expansion. Had there been significant transmission capacity available to transfer electricity to the Western Interconnection from the Eastern Interconnection, it is unlikely that the enormous rise in electricity prices in the Western US could have occurred during this time period. This transmission capacity could have allowed consumers in the Western US to avoid paying prices that were orders of magnitude higher than prices in the Eastern US during this time period. In addition, this interconnection would have also eliminated the need for the State of California to sign long-term forward contracts during the winter of 2001 at prices more than double wholesale prices during first two years of operation of the California market in order to commit suppliers to the California market during the summer of 2001 onwards. A very conservative estimate of the discounted present value of this interconnection to consumers in Western US (because it would have prevented the events of June 2000 to June 2001 from occurring in the Western US) is on the order of 30 billion dollars.

This example emphasizes that it is far more important to assess the benefits of any proposed transmission upgrade at the extremes of system conditions rather than under typical or average system conditions. Only a few benefit scenarios need to be run for typical or average system conditions. Substantially more benefits calculation scenarios should be run for plausible system conditions that yield substantial benefits for the upgrade. Moreover, it would be worthwhile to determine the sensitivity of the benefits measures to each dimension of future system conditions. For example, suppose that the value of a given transmission upgrade is particularly sensitive to the amount of hydroelectric energy available in the Pacific Northwest. This implies that it would be very useful to compute the benefits for scenarios that assume historical lows in hydroelectricity energy availability from the Pacific Northwest.

Because different parties will have different expectations about the future distribution of important sources of uncertainties, it is important that a transmission benefits methodology be able to conveniently and quickly accommodate alternative probability distributions. For instance, if someone wishes to specify a mean and standard deviation for several variables (e.g., fuel prices and load growth), along with correlations among them, it would be possible to translate these assumption into a probability for a set of system conditions scenarios. The TEAM methodology includes this approach in its "moment consistent estimation" method.

Because there are so many dimensions of uncertainty in future system conditions, an alternative view of a proposed transmission expansion is as an insurance policy against a particular combination of future system conditions. In particular, for almost any proposed transmission upgrade there is some combination of future system conditions (for example, hydro conditions, demand growth, and the pattern of new generation investment and retirements) that would lead to locational price differences that cause the benefits of a specific transmission upgrade to be greater than its cost. Identifying these system conditions may be more useful to decision-makers than providing a specific expected benefit number, because the decision can then be framed in terms of the question of what the likelihood is of these particular future system conditions and whether the decision maker wants to purchase insurance (in the form of the transmission upgrade) against them.

To provide a concrete illustration why the realized benefits under extreme system conditions should be more thoroughly investigated than those under typical system conditions, consider the following example. Let B(X) be the realized benefits of the upgrade for given value of an N-dimensional vector of system conditions $X = (x_1, x_2, \ldots x_N)$ such a hydrologic conditions, input fuel prices, demand growth, and new generation capacity. Consider two vectors of system conditions, X and Y. If the realized benefit for system conditions X, B(X), is equal to the realized benefits for system conditions Y, B(Y), then computing B(Y) is of little value in determining the support and shape of the distribution of possible benefits associated with the upgrade. The analyst only needs to know the probability that system conditions Y occur. There is no need to compute B(Y), because it is equal to B(X). Similar logic applies to system conditions Z, where B(Z) is approximately equal to B(X). For system conditions Y, where B(Y) is substantially above or below B(X), computing B(Y) is very useful because it provides valuable information about the range of the realized benefits associated with the upgrade. Moreover, if the analyst is able to determine the sensitivity of B(X) to specific elements of the vector X, this can be very useful for finding those system conditions that are likely to produce very large and very small realized benefits associated with the upgrade.

The fact that X, the vector of future system conditions is N-dimensional, and B(X), the benefits associated with these system conditions, is a scalar, implies that the potential gains associated with putting time and effort into the selection of the values of X at which B(X) is evaluated for a given proposed transmission upgrade can maximize the information about the support and distribution of benefits from the transmission upgrade that can be obtained from fixed amount of computer time available to compute the realized benefits for specific values of future system conditions. This is, in fact, the philosophy behind importance sampling in statistics: the best estimate of some uncertain quantity will be obtained by sampling more intensively from those regions where the quantity is most uncertain.

We recommend that the ISO investigate the sensitivity of the benefits, B(X), with respect to specific elements of X. The ISO should use these results to find the set of values of X that make B(X) greater than the cost of the proposed upgrade. The proposed portion of the TEAM methodology in which probabilities of different scenarios are chosen in order to maximize the net benefits of the upgrade is consistent with this perspective.

2.5. Substitutability of Transmission with Generation/Demand Resources

The MSC recognizes the enormous technical challenges associated with developing a transmission benefits assessment methodology for a wholesale market regime. Rather than simultaneously determine the transmission network along with future generation needs, demand-side participation, and distributed generation, as was the case during the former vertically-integrated regime, the transmission network must be designed to best serve the needs of wholesale market participants. New suppliers are allowed to interconnect to the network wherever they find it most profitable. Load-serving entities would like access to the lowest-priced electricity possible. Distributed generation and renewable resource owners want to serve as many customers as possible.

A last principle that has been identified by the ISO as a required part of a transmission analysis is the consideration of the interaction, or even substitution, of transmission with generation or other resources such as energy efficiency programs. We recognize that all of these resources can represent substitutes or sometimes complements to each other and that the proper balance of these resources would be reflected in a socially efficient outcome.

There is still the question of how public policy tries to achieve socially efficient outcomes. In most industries we rely upon competitive markets to properly weigh and balance the relative merits of various input resources. Most agree that electricity transmission investments cannot be left to a market process. Generation investment, however, has been either directly or indirectly driven by market forces in most of the US for more than a decade. It is therefore hard to separate out the question of whether transmission planning should be integrated within a general integrated resource planning process from the question of how centralized that planning process will become.

In most ways, these questions do not impact the applicability of the ISO's transmission evaluation methodology. The same tools could be used to compare a specific generation resource to a specific transmission upgrade or to compare a hypothetical cluster of market driven resources to that same transmission upgrade. The difference is how one comes up with the hypothetical generation resources for the purposes of comparison.

In its current study, the ISO uses a mix of reliability-driven and economically-driven generation investment to project future resources that would enter by 2013. The resources are all generic and enter according to rough rules of thumb, such as maintaining a 15% planning reserve in each WECC sub-region, and earning sufficient revenues to cover capital costs. While rough, these rules seem reasonable. It should be noted that these new resources are projected to locate themselves in parts of the network that are most able to accommodate that new entry. It is very possible that these are not the places where it is most profitable to site generation, and therefore not the most likely places where generation will be built.

We urge that in the future more effort be devoted to projecting *where* new resources and loads are likely to emerge. One of the key purposes of long-term transmission planning is to pro-actively establish transmission infrastructure to accommodate the evolving pattern of network usage. This involves identifying potential scenarios of resource and demand growth that captures both the quantity of growth and the diversity of locations within the network. Such an undertaking would be consistent with the spirit of developing a transmission infrastructure that can support and provide benefits under extraordinary as well as ordinary, well-organized conditions. Such a projection should account for the interactions of resource locations with transmission decisions. That is, if a proposed transmission reinforcement would induce a shift in the location of new generation or demand-side programs, these shifts should be anticipated and appropriately valued in the net benefits calculation.

3. Stakeholder Comments

Immediately before and during our May 17 meeting, we received comments on the ISO's transmission expansion assessment methodology from a number of parties. The Electricity Oversight Board (EOB) expressed concern with the ISO using only the RSI methodology to determine market prices. The EOB also requested that ISO present detailed breakdowns of the distribution of the benefits of the transmission expansion among the various types of market participants, rather than only present a single aggregate benefit number. The EOB felt that policy-makers should determine which benefit measure to use to assess the viability of a proposed transmission expansion project. As noted above, we recommend that the ISO consider alternative methods for determining market prices. We also recognize that time constraints prevented the ISO from considering other alternatives at this time. We also support the perspective that regulators should determine which benefits measure is used in the assessment process.

Coral Power provided written comments before the May 17 meeting and summarized these comments during the meeting. Corel Power encouraged the ISO to quantify the impacts of the extremes of market participant behavior and rare events on the expected benefits calculation. Coral Power encouraged the ISO to avoid excessive focus on base case fuel price, hydrologic or other system conditions scenarios, but instead concentrate on assessing the insurance value of a transmission line by assessing the benefits of the upgrade under extreme but plausible input fuel, demand growth, hydrologic and other system conditions. As discussed above, we strongly support a comprehensive analysis of the insurance value of the proposed upgrade. As noted above, we encourage the ISO to attempt to find, for each proposed upgrade, the set of system conditions that would cause the total benefits of the project to exceed the cost of the project.

Pacific Gas and Electric (PG&E) argued that the benefits to California ratepayers should be of primary importance in assessing the benefits of an upgrade. PG&E agreed that accounting for the uncertainties in future system conditions is important and that transmission capacity provides insurance against extreme events, but it also urged the ISO not to over-value them. PG&E also argued that a stakeholder process should be used to decide whether an upgrade should be undertaken and that transmission should be part of integrated resource planning process at the state level. As noted above, we do not have a position on which benefits measure should be used. We understand PG&E's concern with overvaluing rare events, but we do not think this should be a reason for not computing the benefits of the upgrade under plausible rare events. After the set of system conditions that lead to significant benefits from the proposed upgrade has been computed by the ISO, a stakeholder process may be the ideal forum for assessing the likelihood of these system conditions occurring in the future, and therefore provide valuable input into the subsequent decision-making process about whether to move forward with the upgrade.

Henwood Energy Services provided written comments and summarized them at the May 17 meeting. Henwood argued for the use of a zonal transmission model appropriately tailored to the specific upgrade being modeled as opposed to the DC Optimal Power Flow (OPF) model used in the current version of the ISO's transmission expansion assessment methodology. Henwood felt that because a zonal model tailored to the specific circumstances could be solved more quickly this could allow a richer model of uncertainty about future system conditions to be considered in the benefits measurement process. Henwood also argued that because the ISO planned to use an AC-OPF to operate the system under the locational marginal pricing market proposed as part of MD02, there was also an approximation involved in using a DC-OPF model in the transmission expansion methodology. As discussed above, we do not believe that the use of a zonal transmission model should be ruled out a priori. However, we believe that more prudent strategy for the ISO to follow is to use a full DC-OPF model as the default network model. Unless it can be demonstrated that an appropriately modified zonal model adequately approximates the behavior of the actual transmission network and resulting locational prices from the DC-OPF, the ISO should continue to require a DC-OPF network model in the assessment process.

The public discussion at the meeting also compared the results from AC-OPFs and DC-OPFs. The general consensus expressed from the ISO's Grid Planning staff is that during the vast majority of system conditions, the difference between DC-OPF solution and AC-OPF solution is very small. Although there are clearly circumstances when there can be significant differences between the solutions from these two load-flow models, our reading of the relevant academic literature on this topic has convinced us of the importance of using a DC-OPF in transmission expansion assessment process and of the adequacy of the approximation of DC-OPF for an AC-OPF for valuing transmission expansions. Nevertheless, we believe that as the ISO begins the transition to the MD02 market and the AC-OPF software is written for this market, comparisons should be made between the AC-OPF solution and DC-OPF solutions from the transmission expansion assessment model.

Southern California Edison (SCE) submitted written comments on May 27, 2004, which was too late for us to incorporate a discussion of them in these comments.

4. Concluding Comments

We believe the ISO has made significant progress on this very important and challenging task. As noted in several stakeholder comments, there are number of directions for refinement of the current version of the methodology. However, we do not believe that any of these refinements should delay the process of moving forward with the ISO's transmission expansion assessment methodology. The ISO should move forward as quickly as possible to begin working with the California Public Utilities Commission and other parties to produce a final methodology that best suits the needs of all parties involved.

APPENDIX: COMPARISON OF TRANSSHIPMENT AND LINEARIZED DC LOAD FLOW MODELS

This Appendix contrasts the feasible set of power injections that result from a transshipment and linearized DC load flow model of the same three-node system. The difference between the two models is that the former, in essence, disregards Kirchhoff's voltage law, allowing power to be routed so that it avoids binding constraints (i.e., as in a valved-pipe network).

Consider the three node network shown below, in which node A is an importer, and nodes B and C are exporters. All three lines have capacity limits as indicated. However, the reactances of the three lines are equal. As a result, the flow from B to A is split 1/3:2/3 between the paths B→C→A and B→A, while the flow from C to A is split 2/3:1/3 between C→A and C→B→A. The next figure shows the net power injections at B and C that are feasible the analogies to both Kirchhoff's voltage and current laws are enforced (linearized DC load flow). The figure shows four constraints that define the feasible region, one for each of the flow limits in Figure 1. The maximum total injection that is possible is 200 MW, split evenly between nodes B and C. If the three nodes have significantly different costs, then other combinations of flows might be preferred (for instance, if B is much cheaper, then the combination of 130 MW injected at B and 40 MW

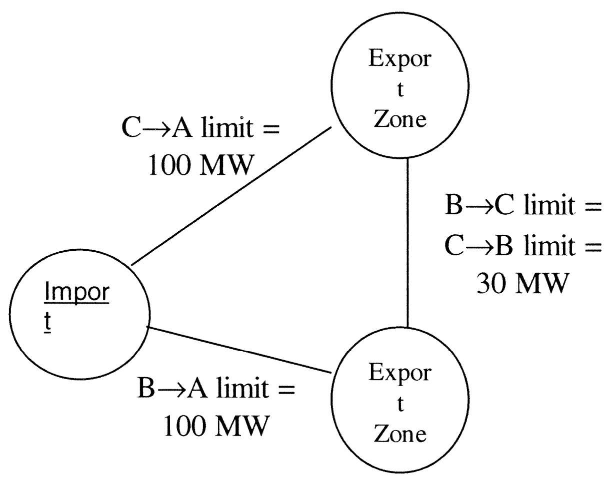


Figure 1. Three node system (lines have equal reactance)

injected at C might instead represent the market equilibrium). If both B and C have cheaper power sources (on the margin) than A, then the dispatch solution will be somewhere along the northeast boundary of the feasible region.

If instead a transshipment model is assumed (i.e., only Kirchhoff's current law is enforced), the feasible set of injections expands, as shown below. A larger feasible region implies that total production costs are likely to be lower (and certainly cannot be higher) than for the network model. It is likely that the benefits of relaxing a transmission constraint will decrease, although the reverse is possible. Therefore, there is a danger of significant bias in the benefits estimate if a simplified network is used.

In order to better represent the set of feasible flows and injections, users of transshipment models sometimes derate individual component capacities. For instance, one might adjust these capacities so that the injections at B and C can never exceed their lowest upper limit in Figure 2 (90 MW, which occurs when the other injection is zero; at this level of injection, the line between B and C is congested). We do this by lowering the capacity of all lines by 30.7%; in the below figure, the resulting feasible region for the transshipment model is superimposed on the full network model's feasible region. The feasible region is now much smaller, and in this case the transshipment model will overstate production costs (and probably overstate the value of a transmission addition).

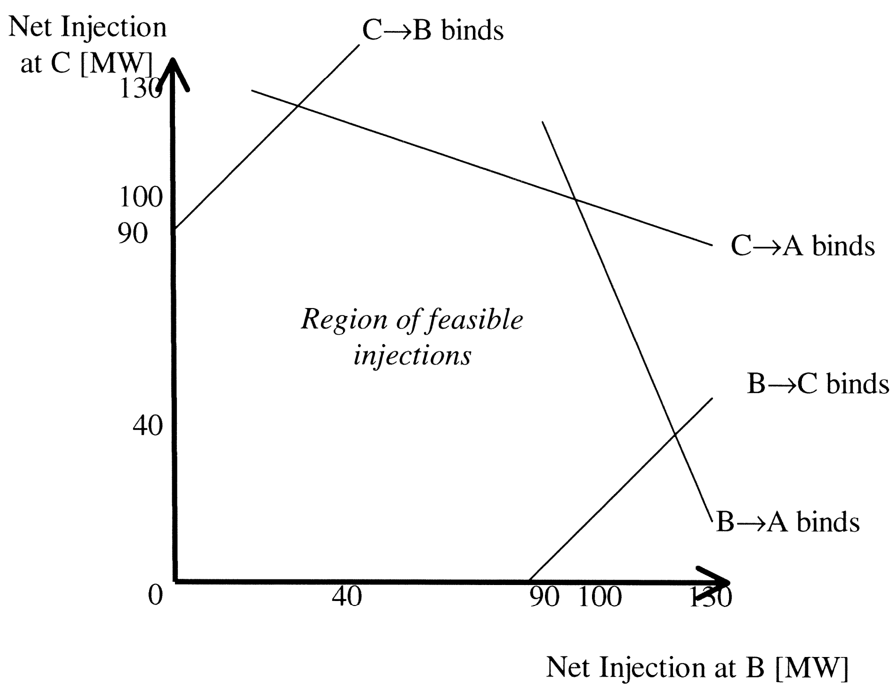


Figure 2. Feasible injections resulting from network (linearized DC load flow) model

Of course, some level of derating between these extremes might result in expected production costs that are close to the value that would be yielded by a full network model. However, because system conditions (e.g., locations and magnitudes of injections) can vary significantly, it is very difficult a priori to determine what level of derating will minimize the bias in production costs for a network. Even if such a bias was minimized for a base case, there might still remain a bias for other network configurations, so the estimated benefits of transmission improvements might be misrepresented. Only if the network is radial in structure will such biases necessarily be absent.

The final figure in this appendix considers how transmission reinforcement affects the feasible regions of Figures 2 and 3. In particular, imagine that a circuit is added to the corridor between A and B, increasing its capacity from 100 MW to 125 MW, and decreasing its impedance by 20%. The left side of Figure 5 shows the change in the feasible injections at B and C for the linearized DC load flow model, while the right side shows the change for the transshipment model. For the latter model, the feasible region expands uniformly to the left (e.g., if there is no injection at C, then B can inject 155 MW, with 125 MW flowing directly to A, and the other 30 MW flowing indirectly to A via C). But the picture is more complex for the linearized DC load flow model, with one constraint becoming tighter. This shows that use of a transshipment formulation distorts not only a "base case" feasible region, but also the nature of the changes to that region when transmission reinforcements are made.

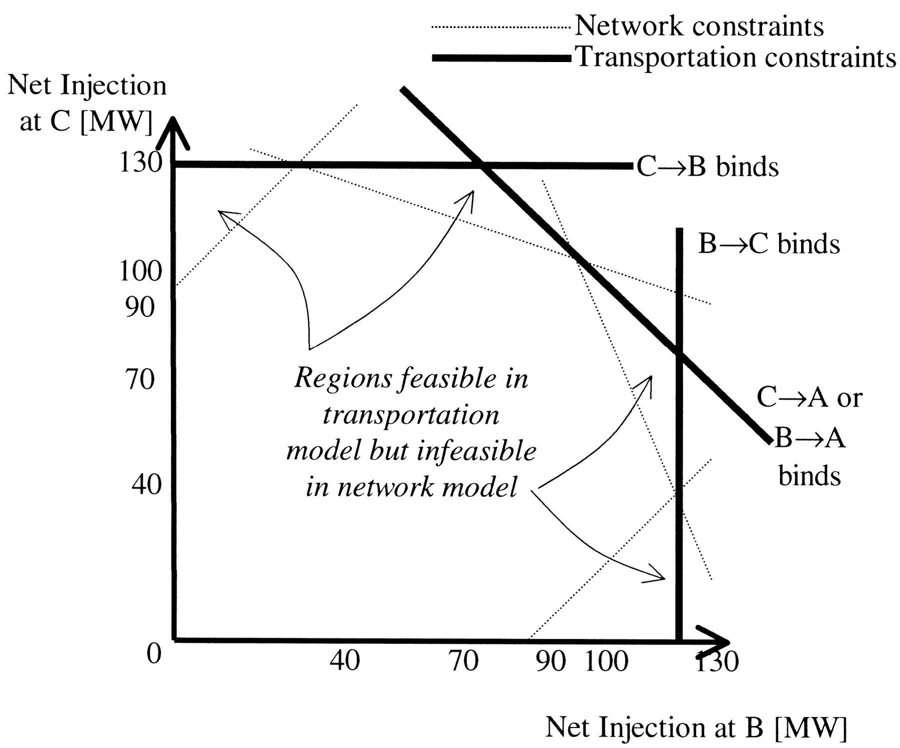


Figure 3. Increase in feasible set of injections resulting from using transshipment model rather than linearized DC network

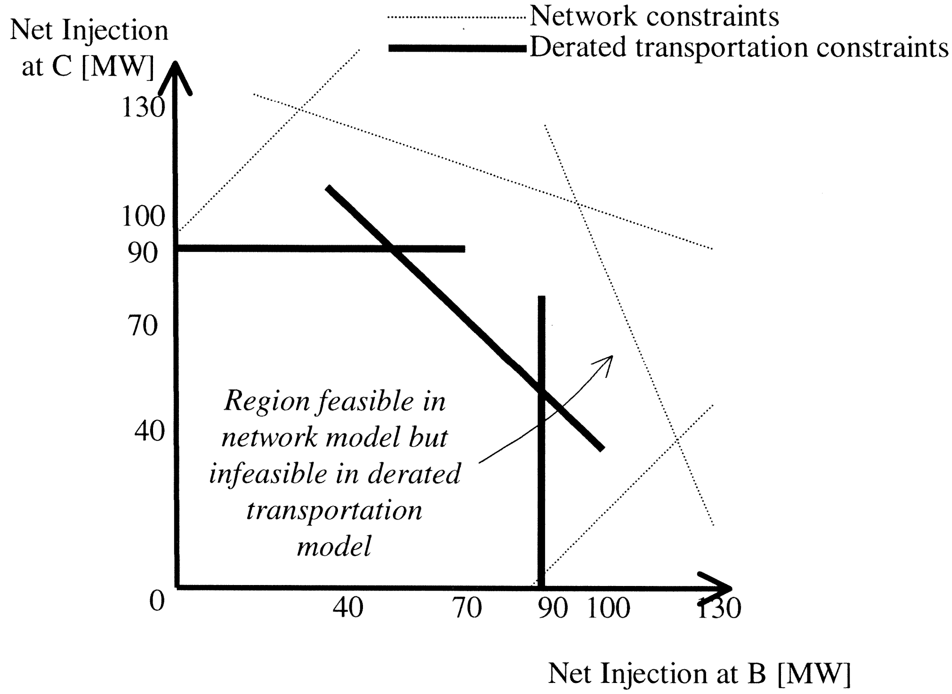
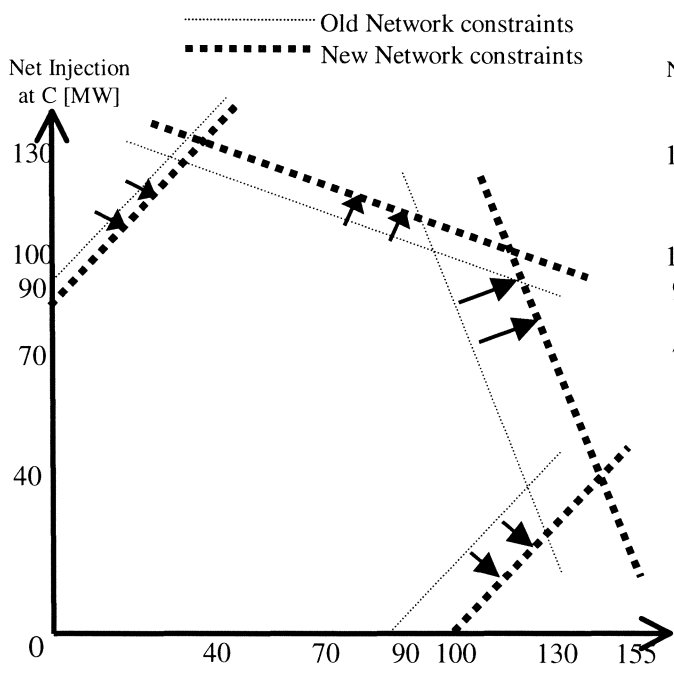


Figure 4. Decrease in feasible set of injections resulting from using transshipment model with derated line capacities rather than linearized DC network



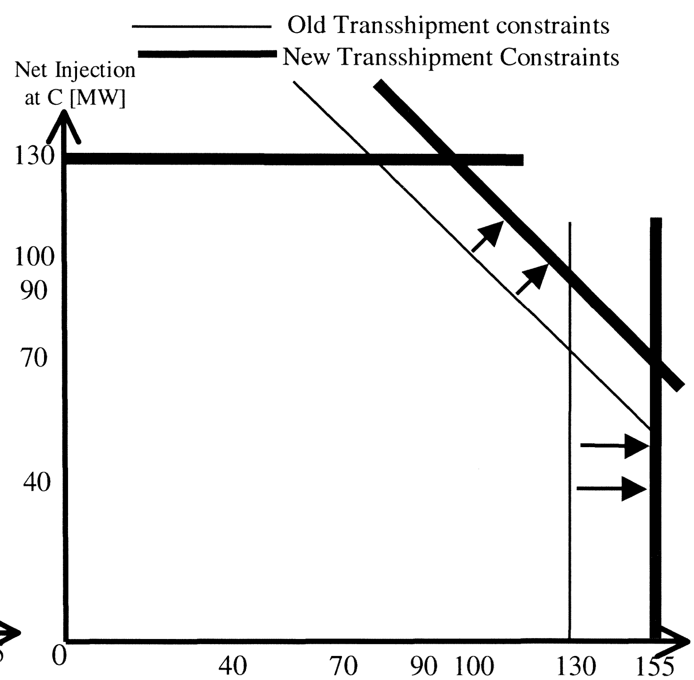


Figure 5. Effect of transmission expansion of 25 MW from B to A. (Left) Effect on feasible injections for linearized DC load flow model. (Right) Effect on feasible injections for transshipment model