BENEFIT ANALYSIS AND COST ALLOCATION FOR REGULATED TRANSMISSION INVESTMENT

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(Revised October 4, 2004)

I. INTRODUCTION

This paper discusses four interrelated issues pertaining to the application of cost benefit tests and cost allocation for transmission investments with regulated cost recovery, as opposed to market based transmission investments that are voluntarily funded by market participants. These issues are 1) the appropriate methodology for measuring benefits; 2) the application of a market test; 3) cost allocation methodologies and 4) modeling considerations relating to both measuring benefits and cost allocation.

II. COST BENEFIT TESTS

Regulated transmission investment projects will be subject to a cost benefit assessment to assure that the benefits of the transmission project exceed its costs. The most difficult element of this assessment is the measurement of prospective benefits. Three general approaches to measuring the economic benefits of regulated transmission investments have been considered by the Midwest ISO. These are to measure 1) the total change in payments for energy and ancillary services[1] by load before and after the expansion; 2) the total change in the as bid production cost of meeting load[2] (energy and ancillary services) before and after the expansion; or 3) the value of the change in transfer capability using pre-expansion FTR values. Each approach is described below and the implications of the various approaches are discussed in subsection D.

A. Change in Load Costs

This approach measures the benefits of a transmission investment by examining the impact of the proposed expansion on the LMP prices paid by load for energy and, if impacted, ancillary services. The basic logic for this approach is that loads will fund the transmission investment and the transmission investment should therefore not be funded unless it reduces payments by loads.

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[1] The ancillary service costs most likely to be impacted by transmission expansions would be the costs of reserves and regulation.

[2] The as-bid costs of suppliers will initially be based on administrative cost measures but will eventually be based on actual spot market costs.

There are several mathematically equivalent methods of measuring load costs.

One approach is to measure the load cost as:

$$\sum Load_i * LMP_i - congestion\,rents - losses\,residual$$

Thus, the load at each bus is multiplied by the LMP price at that bus and summed over all locations. Since the economic value of congestion rents is assigned directly or indirectly to loads,[3] these rents need to be deducted along with the losses residual (if the cost of marginal losses is reflected in LMP prices)[4] to arrive at the net costs borne by loads. If the transmission investment is expected to impact the prices of ancillary services, then the prices paid for ancillary services would be included in the calculation.[5] This measure of benefits can be illustrated with a simple example.

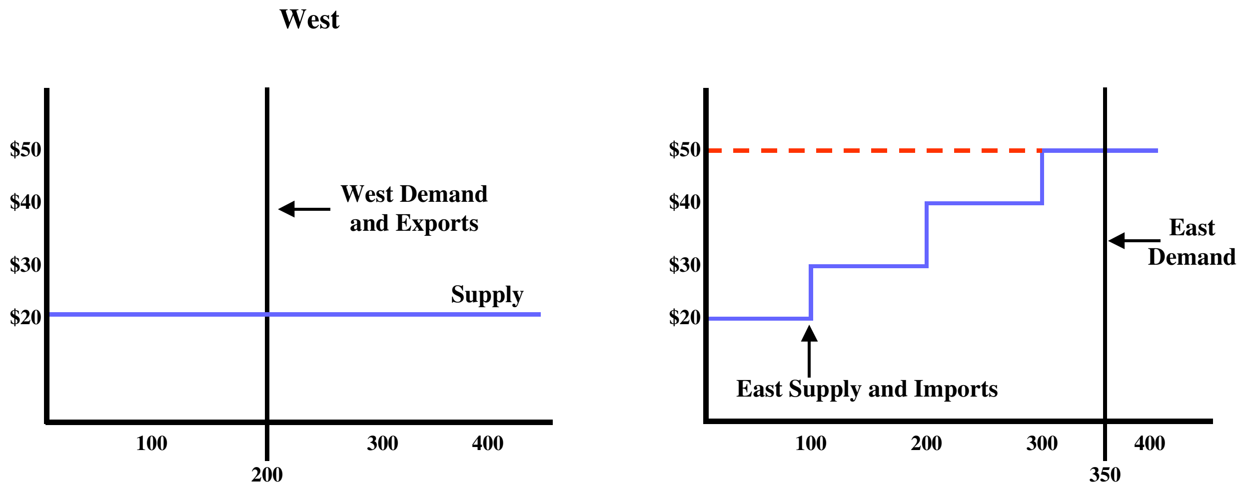
Figure 1 portrays a market with 100 MW of load in the West region and 350 MW of load in the East region. The West region has unlimited generation available at an incremental cost of $20/MWh, while the East region has 100 MW at $30/MWh, 100 MW at $40/MWh and 100 MW at $50/MWh. Initially there is 100MW of transmission from west to east, so Eastern load is met with 100 MW of import power having a cost of $20/MWh, 100 MW of power at $30/MWh, 100 MW at $40/MWh, and 50 MW at $50/MWh. The LMP price in the West is $20/MWh and the LMP price in the East is $50/MWh.

3 The economic value of congestion rents flows to consumers through three basic mechanisms. First, many FTRs will be initially allocated to LSEs. Second, the net revenues derived from the sale of FTRs in MISO coordinated FTR auctions will be credited against the embedded transmission charges paid by MISO transmission customers. Third, any congestion rent surpluses in the MISO coordinated day-ahead market will be credited to MISO transmission customers.

4 The losses residual is the difference between the losses charges reflected in LMP prices and total losses costs. If LMP prices include the cost of losses, then the losses residual will be the product of the net injections at each location on the MISO grid and the loss component of the LMP price at that location minus the total cost of losses (the difference between total injections and withdrawals times the price of energy at the reference bus). If the cost of losses is not reflected in LMP prices, then the additional losses costs need to be added to the costs calculated based on energy prices.

5 For simplicity, the discussion and examples below do not explicitly consider the impact of transmission investments on the cost of A/S (operating reserves and regulation) but it is possible that transmission investments could impact these costs. The cost of ancillary services to loads would be the quantity purchased at each location times the price of that ancillary service at each location.

Figure 1
Pre-Expansion Supply and Demand



The total cost to load is shown in Table 2. Western loads buy 100 MW at $20/MWh, while Eastern loads by 350 MW at $50/MWh. In addition, LMP pricing results in $3000 of congestion rents, which is assumed to flow back to consumers through their FTR holdings. The net costs paid by load would therefore be $16, 500.

Table 2 Pre-Expansion Costs to Load	
West Load $20/MWh * 100 MW	$2,000
East Load $50/MWh * 350 MW	$17,500
FTR Values $30/MWh * 100 MW	-$3,000
Net Load Cost	$16,500

Let us suppose that a transmission investment is proposed that would add 100 MW of transfer capability from West to East at a cost per period of $3,500.[6] Figure 3 portrays the new supply and demand balance. With the increased import capability from the West, the price of power in the East falls to $40/MWh.

[6] Actual cost benefit analysis will have to discount costs and benefits over the life of the transmission investment rather than comparing single-period costs and benefits as in this simplified example.

Figure 3
Post-Expansion Supply and Demand

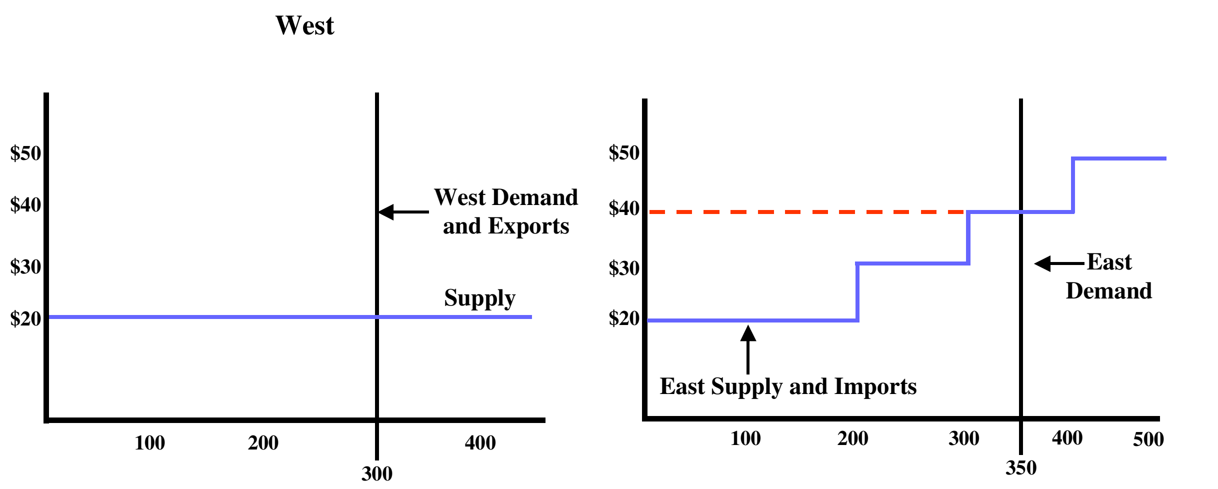


Table 4 shows the post expansion net cost to load. It can be seen that the result of the expansion is to reduce the cost of power to load from $16,500 to $12,500, a reduction of $4,000 compared to an assumed cost of $3500, so this project would pass a cost benefit test based on the impact on load costs.

Table 4 Post-Expansion Costs to Load	
West Load $20/MWh * 100 MW	$2,000
East Load $40/MWh * 350 MW	$14,000
FTR Values $20/MWh * 200 MW	-$4,000
Net Load Cost	$12,000

The calculation of load costs based on the price paid by loads less congestion rents is mathematically equivalent to the total payments to generation:[7]

$$\sum_i Generation_i * LMP_i$$

Thus, the net generation injections at each bus are multiplied by the LMP price at that bus and summed over all locations.[8] In this case it is not necessary to make any adjustment for

7 The relationship between load costs and generator payments is a little more complex if the benefit measure were restricted to the costs paid by internal loads. In that circumstance, the total costs paid by internal loads would be equal to total payments to generation less total payments by external loads.

congestion rents or the cost of losses as they are correctly reflected in this calculation. To this could be added the prices paid for ancillary services if these were impacted by the investment. The total benefits to a transmission investment are therefore

$$\sum_i \left(Gen_i^O LMP_i^O - G_i^t LMP_i^t\right)$$

where ^{O} superscripts the pre-investment values and t superscripts the post-investment values.

Table 5 shows that the value of generation at pre-investment prices is $16,500, while the post-investment value is $12,000. These are exactly the load costs derived in Tables 2 and 4. This equality between load costs and generator payments is definitional and either method can be used to calculate benefits to load.

Table 5
Change in Generator Revenues

Pre-Investment	Post-Investment
West 200 MW * $20/MWh = $4,000	West 300 MW * $20/MWh = $6,000
East 250 MW * $50/MWh = $12,500	East 150 MW * $40/MWh = $6,000
$16,500	$12,000

B. Change in Production Costs

Under this approach the benefits of the transmission investment are measured by the change in the total production cost of meeting load. Thus, rather than valuing the generation injections at each location based on the LMP price at that location, the injections would be valued based on the (as bid) costs. If supplier bids are cost reflective, the change in as bid production costs measures the benefits of the transmission investment from the standpoint of social welfare, i.e., the sum of the change in consumer and producer surplus.

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8 The equality can be seen by observing that

$$\sum_i Load_i \ LMP_i \text{ - } Congestion \ \ Rents \text{ - } \ Loss \ Residual$$

can be rewritten as:

$$\sum_i Load_i \ LMP_i - \left(\sum_i Cong_i Load_i - \sum_i Cong_i Gen_i\right) - \left(\sum_i Loss_i Load_i - \sum_i Loss_i Gen_i - Pref\left(\sum_i Gen_i - \sum_i Load_i\right)\right)$$

which simplifies to:

$$\sum_i Load_i LMP_i - \sum_i Load_i (Cong_i + Loss_i + Pref) + \sum_i Gen_i (Cong_i + Loss_i + Pref)$$

$$= \sum_i Load_i LMP_i - \sum_i Load_i LMP_i + \sum_i Gen_i LMP_i$$

In the notation above, the benefits are measured by:

$$\sum_i G_i^O Cost_i^O - G_i^t Cost_i^t$$

It is simplest to think of $Cost_i$ as measuring the variable cost of the generation segment (fuel variable O&M, emission allowances, etc.), but it can include all costs that vary between the state of the world with and without the transmission investment. As discussed further below, for major transmission investments the costs affected by the investment may include changes in generation investment costs, as well as variable operating costs.

This measure of consumer benefits can be illustrated using the same example discussed above. The pre- and post-investment production costs are calculated in Table 6. The production cost is calculated by multiplying the net generation at each location by its offer price (which will initially be based on administrative cost measures and ultimately based on spot market cost measures). By this measure, the total change in production costs for this investment would be only $2,500, so a transmission investment with a period cost of $3,500 would fail the production cost benefit test.

Table 6
Change in Production Cost

Pre-Investment		**Post-Investment**	
West 200 MW * $20/MWh =	$4,000	West 300 MW * $20/MWh =	$6,000
East 100 MW * $30/MWh =	$3,000	East 100 MW * $30/MWh =	$3,000
East 100 MW * $40/MWh =	$4,000	East 50 MW * $40/MWh =	$2,000
East 50 MW * $50/MWh =	$2,500		
	$13,500		$11,000

C. Pre-Investment FTR Values

It is a fundamental premise of regulated transmission investments that the value of the FTRs awarded in conjunction with the transmission upgrade will be less valuable than the cost of the investment. If this were not the case, the investment could be funded in the market because the market participant that funded the investment would receive direct benefits that would exceed the cost of the project. This relationship applies, however, to the post expansion FTR values, because they may be depressed by the scale of the transmission investment. The value of a transmission investment valued at pre-investment FTR values will place an upper bound on the production cost savings from the transmission investment. Pre-investment FTR values place only an upper bound on the production cost savings because the pre-investment FTR values reflect the marginal production cost savings which will exceed the average production cost savings for substantial transmission investments. Thus, a third way of measuring the value of a transmission investment would be to measure the value of the FTRs attributable to the investment using pre-expansion FTR values.

In the example above, the value of the FTRs that would be made feasible by the expansion (100 MW from West to East) would be $3,000 at pre-investment prices (($50-$20) * 100). The proposed investment would therefore not be economic valued at pre-investment FTR prices if its period costs were $3,500.

While this methodology can only be used to place an upper bound on the production cost savings associated with a prospective transmission investment, this methodology is particularly important because these FTR values can be readily calculated from actual LMP prices and FTR auction prices. This methodology is therefore far easier to apply than the other approaches and is not susceptible to some of the potential errors that could make simulation model results unreliable. Future LMP prices and FTR values may of course differ from current prices, so this method does not necessarily provide a good measure of future benefits. Nevertheless, the current pre-investment LMP prices and FTR values provide a market assessment of the value of the transmission investment if current conditions persisted and a reality check on values produced by other methods. This methodology will only, of course, be able to look forward over the term of FTR auctions and very long term auction results would be unreliable if the term of the awarded FTRs extended into the period in which the prospective transmission upgrade would be in service.

D. Discussion

The change in load costs is conceptually appealing as a measure of transmission investment benefits, since it is ultimately the cost of meeting load that we seek to reduce by implementing a competitive market, improving transmission access, and implementing regional congestion management. Moreover, much of the costs of regulated transmission investments will typically be borne by loads.

The fundamental limitation of the change in load cost approach is that measuring the change in load costs may not provide a very good measure of how a transmission investment will actually impact the prices paid by consumers. On the contrary, it may be that the change in production costs will often provide a much more reliable measure of the actual benefits to load from a transmission investment. There are several reasons for taking such a view.

First, if the total production cost savings associated with a transmission investment are less than the cost of the upgrade, this means that the transmission upgrade is economically inefficient. To proceed with such an investment based on an assessment that the inefficient upgrade will nevertheless reduce the power costs paid by loads must rest on a presumption that the difference between the benefits to consumers and the social benefits will be reflected in a reduction in generator profits. Such an assumption requires that the impacted generators be earning economic profits (i.e., rents) that can be eroded by the transmission upgrade without causing the generators to exit the market. While there can be circumstances in which this assumption is accurate, it is not assured that it would be applicable. If this assumption regarding the incidence of the reduction in prices is not satisfied, the generators impacted by the reduction in prices could exit the market and consumer costs could rise. If the impacted generation could not be allowed to exit, then the reduced market revenues would simply translate into higher uplift or resource adequacy payments by consumers.

Second, even the potential for load cost savings arising from changes in generator rents (i.e., economic profits) requires that the loads be buying power in the spot market at prices that will be impacted by the change in generator rents. This assumption is clearly inappropriate for the rate payers of vertically integrated utilities. For them, the change in production costs is a much better measure of the change in rate payer costs. In effect, the rate regulation of the vertically integrated utility already ensures that any economic rents to generation are appropriately flowed through to consumers. These rate payers therefore only benefit from transmission investments that actually reduce the cost of meeting load, i.e., lead to reductions in production costs. The same logic applies to the customers of vertically integrated public power entities who can only benefit from actual reductions in the cost of meeting their load. Moreover, consumers served by LSEs that are not vertically integrated but have entered into forward contracts to hedge the cost of electricity would similarly derive little benefit from changes in spot prices unless those price impacts were accompanied by real decreases in the cost of meeting load. In all of these circumstances, the benefits to these consumers of a transmission investment are better measured by the gains in social welfare.

This limitation of the consumer cost measure can also be illustrated using our simple example above. Suppose that all of the load in the example was served by a single utility subject to cost of service regulation and that its consumer rate recovered its cost of generation plus $1.500 of transmission costs. The pre-investment consumer charges would therefore be $15,000 or $33.33/MWh as shown in Table 7. The transmission investment would reduce the utility's generation costs by $2,500, as shown in Table 6, but if the project had a period cost of $3,500, the total consumer charges would rise to $16,000 or $35.56/MWh. For the consumers of this vertically integrated utility the impact of the investment on the LMP prices used to calculate the load costs in Tables 2 and 4 is irrelevant because the consumer rates are based on the cost of power generated by the utility's generation and market prices would be paid only for power purchased from other utilities or unregulated suppliers.

Table 7
Impact of Transmission Investment on Ratepayers

Pre-Investment Rate Generation Costs		**Post-Investment Rate Generation Costs**	
200 MW * $20/MWh =	$4,000	300 MW * $20/MWh =	$6,000
100 MW * $30/MWh =	$3,000	100 MW * $30/MWh =	$3,000
100 MW * $40/MWh =	$4,000	50 MW * $40/MWh =	$2,000
50 MW * $50/MWh =	$2,500		
Transmission Cost =	$1,500	Transmission Cost =	$5,000
Total $33.33/MW	$15,000	Total $35.56/MW	$16,000

Third, meaningful estimates of the impact of transmission investments on LMP market prices must take account of the entry and exit decisions of marginal generators. In other words, transmission expansions that reduce the prices paid by consumers also reduce generator revenues, which can cause generation to shut down, partially offsetting the impact of the investment on consumer prices. For example, while the construction of transmission upgrades into load pockets may have a material impact on LMP prices within the load pocket if the generation resources within the load pocket are held constant, the actual impact of a transmission upgrade may be to cause a high operating cost low variable cost generator within the load pocket to shut-down and no longer be available, while low fixed operating cost high variable cost gas turbine remain in operation because less operating profits are required to keep the GTs in the market. As a result the GT continues to set market prices after the transmission investment in many hours, reducing the apparent benefits to consumers from the transmission investment. Analyses that hold generation resources constant may therefore find large benefits from investments that actually would have little or no long-run impact on market prices.

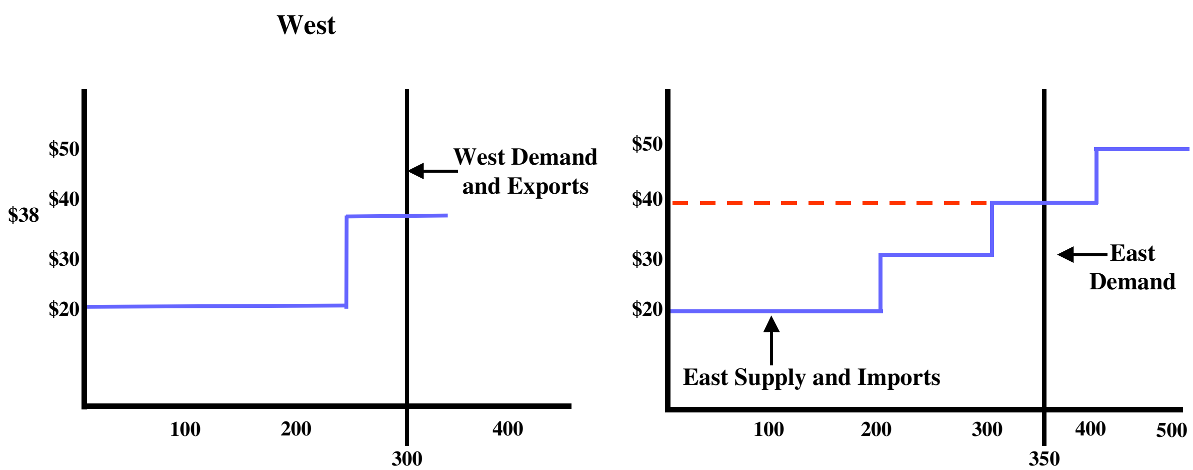
The potential impact of such exits can also be illustrated using the example above. The reduction in load costs of $4,000 shown in Tables 2 and 4 assumed that all of the generation remained in operation. Suppose, however, that without the profits earned during high load conditions when the GTs were on the margin and prices were $50/WMh, the intermediate unit with costs of $40/MWh could not recover the going forward costs required to keep the unit available and ceased operation, while the $50/MWh GTs remained available. Table 8 shows that in this circumstance the post investment load costs would be $13,500, a reduction of $3,000 rather than $4,500, and the post investment production costs would be $11,500, a reduction of $2000. If this transmission investment had a cost of $3500, even loads buying all of their power in the spot market would not benefit from this investment, because the potential reduction in load costs would be diminished by the exit of marginal generation.

Table 8 Post-Investment Prices and Costs with Exit					
Load Cost			**Production Cost**		
100 MW * $20/MWh	=	$20,000	300 MW * $20/MWh	=	$6,000
350 MW * $50/MWh	=	$17,500	100 MW * $30/MWh	=	$3,000
-200 MW * $30/MWh	=	-$6,000	50 MW * $50/MWh	=	$2,500
		$13,500			$11,500

Conversely, benefit analyses of major transmission investments based on market price impacts that hold the generation mix constant will often find that the impact of the investments is to raise consumer costs, so that the investments would appear uneconomic under the consumer cost standard even if the investments were zero cost. This outcome arises because the pre-investment supply of excess generation in the low cost region is often quite limited, precisely because transmission constraints prevent the dispatch of much additional low cost generation, so the additional low cost generation is not built. If the transmission constraints are suddenly removed in a simulation of the impact of a transmission upgrade but the generation supply is left unchanged, one will often find that the same high cost generation is needed to meet load much of the time and prices rise in many hours in the regions previously served by constrained down low cost generation. These price increases may even appear to swamp the impact of price reductions within the constrained area.

This phenomena is illustrated in Figure 9, which modifies Figure 3 to assume that there is only 250 MW of Western generation available at $20 and another 200 MW available at $38/MWh. Post investment, the price of power in the East would fall to $40/MWh while the price of power in the West would rise to $38/MWh.

Figure 9
Post-Expansion Supply and Demand



It can be seen in Table 10 that the total cost to load actually rises from $16,500 to $17,400 after this investment, although production costs fell from $13,500 to $11,900.

Table 10
Post-Investment Prices and Costs with Limited Western Supply

Load Cost	Production Cost
100 MW * $38/MWh = $3,800	250 MW * $20/MWh = $5,000
350 MW * $40/MWh = $14,000	50 MW * $38/MWh = $1,900
-200 MW * $2/MWh = -$400	100 MW * $30/MWh = $3,000
	50 MW * $40/MWh = $2,000
$17,400	$11,900

In practice, however, if such investments in the transmission system were undertaken and prices rose in the constrained down region, more generation would be built in the low cost region, limiting the rise in market prices. In order to develop accurate estimates of the price impact of transmission investments, it is therefore important that the benefit analysis correctly account for the impact of the investment on entry and exit decisions. While benefit analyses measuring production cost savings will also be impacted by errors in accounting for entry and exit decisions, such errors will generally have less impact on the assessment of production cost savings because the production cost calculation is based on the total change in costs, not just the change in incremental costs at the margin.

These considerations suggest that it may be desirable to rely on measures of production cost changes to determine consumer benefits, particularly if many consumers are served by vertically integrated entities.

The third approach to measuring benefits, based on pre-expansion FTR values, is similar to measuring the change in production costs because it effectively assumes away the price effects of the transmission investment and uses pre-expansion FTR values to value the upgrades. As noted above, this approach will generally overstate the benefits of transmission investments that lead to substantial changes in transfer capability, because the marginal benefits will in practice be decreasing with scale rather than fixed as assumed for this calculation. In addition, this test focuses on measuring the benefits of the prospective investment in the near-term and thus would not capture the impact of expected changes in market conditions on the benefits produced by the investment. Nevertheless, it is useful to test whether such an investment would be beneficial if it were already in place and this test is a particularly useful measure of benefits because an estimate of benefits can be calculated directly from pre-investment LMP prices and FTR auction prices that reflects actual market conditions and current expectations, avoiding the need to develop and apply a simulation model to estimate either the change in load costs or the change in production costs.

III. MARKET TEST

An underlying premise of applying cost benefit analysis to regulated transmission investments is that the investments under consideration not only yield social benefits that exceed their social costs and thus ought be undertaken, but that these investments need to funded outside the market because they are uneconomic if evaluated on a market basis. Free rider effects associated with scale economies in transmission and with retail access are often suggested as reasons for such an outcome. Suppose, for example, that the per period cost of the transmission project in the prior example were only $2500. If evaluated at pre-investment FTR prices ($30/FTR) reflected in Figure 1, a project increasing transfer capability by 100MW, would produce $3000 in FTR values. As shown in Figure 2, however, this investment would lead to a fall in Eastern prices, so that the post-investment FTR values would be only $20/FTR, so a project increasing transfer capability by 100MW would only create FTR values of $2000, less than the assumed cost of the project. If the customers of a single LSE would benefit from such an investment, such an LSE would nevertheless find it cost effective to undertake the investment, as the LSE and its customers would capture the benefits both in FTR values and in price impacts. If there were a large number of LSEs benefiting from the price reduction, as might be the case in a state with retail access or if the transmission investment impacted the customers of a number of distribution companies, no single LSE might find it cost effective to undertake an investment that is unambiguously cost effective for load as a whole. This circumstance is the rationale for regulated transmission investments.

It should therefore be the case for all of the regulated transmission investments under evaluation that it is simultaneously true that:

1. Social Benefits > Project Cost[9]

2. Market value < Project Cost

A primary form of market value created by transmission investments would be the FTRs made feasible as a result of the investment.[10] If the same cost benefit study that finds that the social benefits exceed the social costs also yields LMP prices implying that the FTR values would also exceed the costs of the project, there needs to be further review of why the transmission project needs to funded through a regulatory mechanism, rather than funded by the market based decisions of market participants. If it is known that no market participants are interested in funding the investment yet the study used to measure benefits also predicts that the investment would be highly profitable on a market basis, this is an indication that there is something wrong with the study used to measure benefits.

IV. COST ALLOCATION METHODOLOGY

A. Overview

If it is the case that the market value of a proposed transmission investment is less than the cost of that upgrade (due to free rider effects) but the investment passes the overall cost benefit test, then the issue arises of how the project should be funded, i.e., who pays for it. The FTRs made feasible by the transmission upgrade could be auctioned, but the sale of these FTRs would by definition not yield sufficient revenues to cover the cost of the transmission upgrade (if they did the investment would pass the market test discussed above (market value greater than private costs) and would not need to be undertaken as a regulated investment). It is therefore necessary to require the beneficiaries to pay for these transmission investments and some mechanism must be used to assign these mandatory payments to the beneficiaries.

Before turning to discussion of mechanisms the MISO could use to assign the cost of transmission upgrades to beneficiaries, there is a quasi market alternative that avoids the need for the MISO to perform this cost allocation role that warrants consideration. This quasi-market approach would rely on state regulators to perform the cost allocation role, in those cases in which this is appropriate. After discussing the quasi market approach, there is a consideration of alternatives for MISO assignment of these costs.

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9 The project costs is the revenue requirement for the transmission investment. For simplicity we assume that these costs are the same regardless of how the project is funded.

10 In a market with an ICAP market similar to those in the eastern ISOs, there might be additional private market value in the form of ICAP delivery rights.

B. Quasi-Market Approach

In this approach, once the MISO has undertaken a cost benefit analysis in its transmission planning coordination function, the mechanism for market-based investments could be relied upon for carrying out the regulated investments in certain circumstances. In circumstances in which the beneficiaries are consumers largely located within a single state and the distribution companies serving those consumers are largely state jurisdictional, there is a potential to rely on agreements between the state regulatory commission and the local distribution companies subject to its jurisdiction and serving consumers that benefit from the transmission investment to determine the investment shares of the distribution companies in the transmission investment. With the investment responsibility thus determined, the MISO could treat the project like any other market based investment, awarding FTRs to the distribution companies that fund the investment reflecting the increase in transfer capability provided by the upgrade.

This quasi-market approach has the benefit of avoiding the need for the MISO to determine beneficiaries and assign costs and provides a framework for state regulators to carry out this function with their jurisdictional utilities.[11]

This approach will not be sufficient, however, if the beneficiaries are spread across multiple states or if important beneficiaries are served by distribution systems that are not subject to the state regulators. A fallback MISO allocation approach is therefore needed.

C. MISO Allocation Approaches

If it is necessary for the MISO to identify beneficiaries and assign transmission investment costs to the beneficiaries, there are a number of potential approaches that could be applied.

1. Production Cost Impacts

Since changes in production costs are likely to provide the most reliable measure of the overall consumer benefit from transmission upgrades, it may appear appropriate to assign costs based on the incidence of these changes. This would not be appropriate, however, as the location of the change in production costs generally does not have much relationship to the location of the benefits. The location of production cost savings merely reflects the change in the generation dispatch resulting from the transmission upgrade and provides little insight into the beneficiaries of the investment.

2. Market Price Impacts

Given the irrelevance of production cost changes for identifying beneficiaries, another possible approach would be to rely upon market price impacts. While such evaluations of price impacts for benefit analyses are necessarily based on forward looking analyses, it should be kept in mind that cost allocation processes can potentially take advantage of the observed post investment

[11] In states with no retail access, minimal regulator involvement would be necessary for transmission investments most of whose benefits accrued to the customers of a single distribution company.

outcomes, rather than relying solely on forecasts. Whether based on forward looking simulations or actual market data, there are several factors that need to be accounted for in applying such an approach.

First, as noted in the initial discussion of forecasting market price impacts, transmission investments impact generation entry and exit decisions, and generator entry and exit decisions can have a material impact on market prices. Thus, any analysis of market price impacts for the purpose of assigning benefits must take account of how the transmission investment would impact generation entry and exit. Prospective analyses must predict what generation projects will be built, will not be built, will shut down or will not shut down if a particular transmission upgrade goes forward. Perhaps less obviously, a similar need arises if the cost allocation is retrospective and based on actual market outcomes, as it would then be necessary to predict which plants would not have been built or would not have exited had the upgrade not been made in order to assess what prices would have been had the transmission investment not been made. This retrospective analysis for the purpose of cost assignment will be easier to develop than a prospective analysis, however, because it will be possible to observe which plants did in fact either enter or exit the market following the investment, although causation may at times be ambiguous.

Second, the magnitude of any price impacts attributable to a transmission investment will depend in part on market participant bidding strategy, fuel costs, load growth and generation and transmission outages. After the fact benefit analysis has the advantage of being able to take account of the actual realizations of these variables, rather than relying solely on forecasts.[12] After the fact allocation of benefits may not be attractive to the market participants that will have to pay these charges, however, because the market participants would not know in advance what their cost exposure would be.[13]

A third consideration is whether the allocation of costs will be in proportion to price impacts or whether costs will be allocated equally to all benefiting consumers. Many of the difficulties in estimating price impacts arise in quantifying the magnitude of the price change, not in assessing the direction of the price change. The sign of the impact of potential transmission investments on prices at various locations would likely be much less sensitive to the details of the assumptions regarding entry, exit, load growth, and fuel costs than would the estimate of the magnitude of the impact. This approach might be made more workable if the residual investment costs were allocated equally to all consumers benefiting from the price reductions, without an effort to precisely weight the allocation of investment costs to customers by the calculated benefits.

Aside from these estimation issues, other important choices to be made in applying this kind of cost allocation methodology include: a) should the analysis consider benefits to generators that receive higher prices as a result of the transmission investment; b) should special

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[12] In accounting for the impact of generators that are assumed to exited because of the transmission upgrade, however, it would be necessary to make assumptions regarding bidding patterns, fuel costs and availability had the investment not been made and the plant not ceased operation.

[13] This would likely be less of a concern if recovery of the allocated costs in a non-by passable distribution charge is assured.

consideration be given to consumers that pay higher prices as a result of the transmission investment; c) should impacts on ICAP prices or more generally the cost of complying with resource adequacy requirements be taken into account; and d) should account be taken of whether consumers are served by vertically integrated utilities or buy power on the spot market.

There are many possible variations within the general category of market impact based cost allocation methodologies. One variation that may be appropriate if the MISO were to utilize production cost savings as the criterion for measuring benefits, would be to allocate costs using the following formula:

$$S_i = \frac{\sum_{i \in j} \Delta Gen_i (LMP_i^t - Cost_i)}{\sum_i \Delta Gen_i \left(LMP_i^t - Cost_i \right)} * Unrecovered\, Investment Costs \qquad [1]$$

where:

ΔGen_i	=	Change in generation at location i between the pre-investment case and the post-investment case (ΔGen_i is negative if the investment leads to reduced generation).
LMP_i^t	=	LMP price at location i post-investment.
$Cost_i$	=	Cost of the change in generation.
Unrecovered Cost	=	The excess of the project cost over the auction revenues collected from the sale of FTRs made possible by the expansion.
j	=	A region.

The logic of this formulation has three elements. First, at any location at which ΔGen_i is negative, it will be the case that $(LMP_i - Cost_i) \leq 0$, because generation would not be dispatched down if its cost was less than the market price. The load served by this generation therefore benefits by the difference between LMP_i and $Cost_i$ because the load is served at a lower cost than it could be served by its own generation. Second, at any location at which ΔGen_i is positive, it will be the case that $(LMP_i - Cost_i) \geq 0$, because generation would not be dispatched up if its cost exceeded the market price. The incremental sales at a price above cost would benefit the generation owner. Third, mathematically, the total production cost savings from the investment

$$-\sum_i \Delta Gen_i Cost_i \qquad [2]$$

can be rewritten as:

$$-\sum_i \Delta Gen_i Cost_i + \sum_i \Delta Gen_i LMP_i \qquad [3]$$

$$- \sum \Delta Gen_i (Pref + Cong_i + Loss_i)$$

$$= \sum_i \Delta Gen_i (LMP_i - Cost_i) - \sum \Delta Gen_i Cong_i$$

$$- \sum \Delta Gen_i (Loss_i + Pref)$$

The first term in Equation [3] are the benefits to loads and generators that would be used to allocate the residual transmission investment costs. The second term is essentially the market value of the FTRs made possible by the transmission investment. This component of the costs should be recovered through the sale of the FTRs made possible by the expansion and therefore does not have to be allocated to MISO transmission customers. The third term are the benefits, if any, of the transmission investment in reducing the cost of losses. It is anticipated that this benefit would generally be small. If it is material, a share of the residual project costs would be assigned to those who would benefit from the reduction in the cost of system losses.

It is proposed that the cost allocator S_j would be calculated for regions and would define the share of the unrecovered project costs (product costs in excess of FTR auction revenues) that would be assigned to entities in the relevant region. A possible elaboration on this approach would be to only include in the calculation of S_j those locations for which the change in between the pre-investment and post investment price is 5 percent or more. This would avoid assigning costs to regions impacted only to a trivial degree by the investment.

It is noteworthy that if this allocation rule were applied to a true reliability investment, all of the costs would be assigned to the customers of the distribution company undertaking the reliability investment because the impacts on generators outside the region would be small (a reliability investment should not be large enough to raise market prices elsewhere in the MISO by more than 5 percent, nor to decrease the prices paid by customers of other distribution companies by more than 5 percent).

The operation of such a cost allocation rule can be further clarified by applying it to the examples used in the discussion above.

Consider first the impact of the transmission investment portrayed in Figures 1 and 3.

The benefits in the West would be

ΔGen_{West} ($LMP_{West} - Cost_{West}$) = 100 MW (20-20) = 0

The benefits in the East would be:

ΔGen_{East} ($LMP_{East} - Cost_{East}$) = -50 (40–40) - 50 (40–50) = 500.

The share of the benefits received by Eastern load would be 100 percent.

It can also be seen from Table 6 that the total change in production costs was $2,500. In this example, $500 takes the form of price impact benefits to Eastern load and $2,000 is the post-investment value of the FTRs made possible by the expansion (100 * (40-20)).

The application of this rule can also be illustrated using the example portrayed in Figures 1 and 9. For this example:

Western benefits are:

$$50 \bullet (\$38–\$20) + 50 * (\$38–\$20) = \$900$$

Eastern benefits are:

$$-50 (\$40–\$40) - 50 * (\$40–\$50) = \$500.$$

Thus, customers in the East would be assigned 5/14 on the unrecovered costs and customers in the West would be assigned 9/14.

The total change in production costs is $1,600, with $200 reflected in the post-expansion value of the FTRs made possible by the expansion (100 * ($40-$38)) and the remainder reflected in the customer benefits.

There are two issues in applying such a benefit allocation rule that ought to be highlighted. First, while this methodology measures total benefits in the impacted region, it does not by itself identify the specific customers receiving these benefits. In the example above, for instance, if all of the Eastern generation that is backed down is owned by net short LSEs, then it is reasonably easy to identify the specific LSEs within the region that benefit from the investment, since as a result of the transmission investment the LSEs would be able to cover their load at a lower cost in the spot market than by using their own generation. If some of the impacted generation is sold on a short-term basis, however, assignment of the benefits to specific LSEs may be more problematic. An important implementation choice is whether the methodology should attempt to assign the benefits to specific LSEs or merely to all LSEs in the impacted region.

In the second example, the beneficiaries in the West are the entities that own the generation that is dispatched up. Another important implementation choice is whether the costs assigned to regions in which ΔGen > 0 will be assigned to resource owners and the set of resource owners to which this will be assigned (pre-investment resource owners or post-investment resource owners).

While it may in some contexts appear fair to assign some of the benefits to post-investment resource owners, assignment of transmission costs to generation entrants could deter the very entry that is needed for the investment to be beneficial.

3. All Consumers

An alternative approach would be to not attempt to assign the price impact benefits to specific consumers but to simply move forward with all transmission investments that pass the cost benefits test and spread the residual investment costs over all consumers in the MISO region.

This approach has the potential to charge consumers for transmission projects from which they derive no benefits (or that even raise the prices paid by some consumers) which may delay rather than speed needed transmission investments by increasing the number of parties that are strongly opposed to the investments. If the costs are assigned largely to those consumers that will in fact benefit, as much as they would like to shift the costs to others, those consumers would be less inclined to take actions that stall needed transmission investments.

4. Generic Transmission Regions

Rather than spreading transmission investment costs over the entire MISO footprint, the MISO and its market participants could define some logical but reasonably broad transmission investment regions. The MISO benefit analysis would then merely need to identify the general transmission investment region in which the price impact benefits are concentrated, which would usually not require extensive analysis, and then allocate the residual investment costs equally to all consumers within the region.

It is possible that this approach would have the same problems as the MISO wide approach. If it is perceived that the actual price impacts of a transmission investment are concentrated within a subsection of the region, those that do not benefit from the investment may have an incentive to oppose or delay such investments. It is also possible, however, that there may be cohesive regions that while not similarly impacted by every single potential transmission investment would be similarly impacted by the kind of major transmission projects that would give rise to material free rider problems.[14]

5. FTR Auction

Rather than trying to estimate energy prices with and without the transmission investment, which would entail either using a simulation model or rerunning a unit commitment model, an alternative approach for assessing the pattern of benefits might be to rerun annual FTR auctions with and without the upgrade to identify the impact of the investment on congestion costs and patterns. The proportionate allocation of the costs to consumers located at particular buses or groups of buses could then be based on the relative impact of the expansion on FTR prices at that bus.

A fundamental limitation of using FTR auction results to allocate costs among consumers is that FTR bids submitted in auctions either before or after completion of a transmission investment will show too little impact of the investment on FTR values because they will be too

[14] Keeping in mind, however, that how such a transmission investment would impact rate payers could vary from LSE to LSE depending on the degree of vertical integration and forward hedging.

elastic around expected congestion values.[15] Conceptually, one needs to calculate FTR values without the investment based on bids that assume no investment and then calculate FTR values with the investment based on bids reflecting the existence of the investment. While this impact measure can be calculated by comparing prices across auctions, such comparisons would be compromised by the many other changes in expectations, regarding demand, fuel prices and generation outages between the two auctions. It is unclear whether comparisons of results across auctions separated in time by a year or more could even produce a reliable measure of the direction of the impact of the transmission investment on consumers across regions within MISO.

6. Conclusion

Overall, the second and fourth approaches appear to provide the best alternatives for assigning costs.

V. MODELING CONSIDERATIONS

There are a number of practical implementation issues in estimating either market prices or production costs for the purpose of estimating benefits or for identifying beneficiaries.

A. Generation Incremental Costs and Availability

There is a fundamental choice in estimating prices whether they are to be estimated based on estimated cost based bids or on actual bidding patterns. It is in general preferable to utilize actual bidding patterns. This would be difficult to implement in a forward looking simulation, however, because the bid patterns would need to be associated with the correct system conditions (high load, low load, transmission outages, generation outages, fuel price changes, etc., in order to provide accurate estimates of price impacts. For example, if a large oil fired generator submits higher offer prices relative to its fuel costs whenever gas prices are very high because high gas prices raise the cost of its competitors, simulations will not accurately capture the impact of this bidding behavior on prices unless the simulations also raise this generators offer prices in conjunction with gas prices. Simply raising the generators' offer prices in 15 percent of all hours will not replicate real-world outcomes because the generator will face low cost gas competition in most of these hours.

Trying to develop a forecast simulation while matching assumed demand and supply conditions with bidding strategies, however, would also be complex. It may therefore be more appropriate to use a combination of backward looking reruns of actual market data and forward looking simulations to assess the likely range of market price impacts. One advantage of the pre-investment FTR value method of assessing aggregate benefits is that the FTR value methodology is based on actual market bids and outcomes and avoids the need to simulate the interrelationships between bidding behavior, supply conditions and demand conditions.

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[15] Because FTR values are relatively price elastic, LSEs potentially impacted by the allocation rule could potentially impact the allocation of investment costs through such a procedure by submitting bids that ensure that the demand for FTRs into their region is very price elastic.

B. What Model Used for Calculation

It is important in simulating market outcomes to use a modeling tool that replicates reasonably well the outcomes in the MISO coordinated day-ahead market. Models that are simplified by omitting some kinds of transmission constraints, that omit or inaccurately model A/S requirements or that utilize greatly simplified unit commitment algorithms may produce results that differ materially from actual market outcomes.

From this perspective, the best approach to simulation would therefore be to use the actual DAM market engine, but use of this tool may be too slow and resource intensive, especially for cost allocation. A further consideration in using actual DAM market outcomes is that the DAM market includes price sensitive load as well as virtual supply and demand bids that reflect expected market outcomes, so the estimated total payments by load and generation may be impacted in unintuitive ways if the day-ahead market is simply rerun with additional transfer capability. A compromise approach may be to use a simplified production cost model that solves for price inelastic demand but has been calibrated against actual day-ahead market outcomes. This modeling issue can also be addressed by the use of pre-investment FTR values for the benefit analysis, as these calculations do not require rerunning DAM results while also avoiding the potential errors from relying on the results of simplified simulation models.

C. Assumptions Regarding Future Additions and Retirements

As observed above, estimation of transmission investment price impacts can be sensitive to the modeling of generation exit and entry. The analysis of entry and exit decision requires that the analysis take account of the full cost of generation capacity, not merely the dispatch costs.

D. Assumptions Regarding Future Loads, Fuel Costs

The simulation of the price impacts of a transmission investment will often be sensitive to the assumed rate of growth of load across regions and the level of fuel costs. The future level of economic activity and time path of fuel prices are, of course, unknown but the impact of these uncertainties can be accounted for through analysis of multiple scenarios.