Published in The Electricity Journal
March 2004

Transmission Investment Valuations: Weight Project Benefits

By Dr. Rajat K. Deb, LCG Consulting

It is no secret that the rate of growth in power generation across the U.S. measured against the existing asset base has outpaced new transmission investments for some years.

As a result, some parts of the country (such as ERCOT) have large reserve margins, yet transmission projects in chronically congested areas (southwestern Connecticut, for example) have barely made it out of the starting gate. The blackout of August 14th, 2003, caused a very public spotlight to be shone on the increased demands put on the grid, in terms of the amount of long-distance flows of electricity,[1] and on the job of grid operators, who need to keep the system conditions within manageable tolerances regardless of the flows. Whether a lack of investment in transmission actually contributed meaningfully to the recent blackout or not, it is now more difficult than ever to ignore the fact that where reliability is at stake, transmission infrastructure investment and coordinated grid operations cannot be left in a state of limbo.

The magnitude of investment that will actually be needed for the next several decades is open to debate, as estimates vary widely about how much new capacity will be necessitated by demand growth and new generation facilities.[2] While projections about the longer term are useful, the combination of local load growth, siting of generation and congestion will likely lend more immediate impetus to particular projects.

Before any broad conclusions about who should fund investment and what costs can be passed on to customers can gain traction, it is necessary to be able to articulate the value of projects in terms of more than just traditional reliability measures such as loss-of-load probability or MWh of unserved energy. As the blackout showed, even if one's own service territory appears secure, events in a neighboring area may overwhelm even thorough planning. Whether costs are spread among different stakeholders, or responsibility is given to a new set of transmission owners or to formerly integrated utilities, those who bear the cost will not do so without some idea of what the infrastructure provides, both in terms of operational stability, and in terms of increased revenues or reduced costs.

Lingering Regulatory Uncertainty

There are a few well-known reasons for relatively modest transmission spending in the face of some obvious bottlenecks. They include a lack of incentives for the traditional transmission owners and operators, meaning the investor-owned utilities, as well as regulatory uncertainty as deregulation and competitive market behavior have evolved. A political tug-of-war over the Federal Energy Regulatory Commission's plans for Regional Transmission Organizations (RTO's) has recently reached a standoff, as utilities such as the Bonneville Power Administration and Southern Company appear to have prevailed in Washington in minimizing requirements that they fund projects that they fear may lower their overall performance. They are resistant to potential requirements that they take part in funding new transmission projects that enable merchant power generators to not only produce power for local consumption but potentially send it elsewhere, given adequate existing generation resources. As flows of electricity cannot be directed to follow a particular path, merchant generators might be justified in saying that utilities cannot be free-riders on system expansions or upgrades simply because they do not initiate them.

Measuring Value and Benefits

An important goal of transmission investments, especially for the Federal Energy Regulatory Commission, is improving economic efficiency by increasing loads' access to low-cost generation and vice versa. There is considerable debate concerning - and a variety of approaches for computing - such efficiency. To be sure, there is disagreement regarding the extent to which transmission investment for economic efficiency reasons should be provided in a regulated manner with guaranteed cost recovery, as opposed to being provided in a market-based manner.[3]

With even a general consensus yet to emerge on power and transmission pricing, as well as transmission ownership and control, the return on any transmission investment carries substantial uncertainty. Behind these matters are questions about the mixture of market-based mechanisms, incentives and prohibitions that can foster reliability. These questions need not be fully resolved in order to carry out analysis of the potential benefits of transmission investment to be realized through reduced congestion costs and greater competition among generating units. The approach that we illustrate does not proscribe who in fact pays for the investments, but quantifies their operational and market effects, and their consequent value for various market participants. In this way, valuation based on operational and market effects may suggest alternative market mechanisms for capturing or signaling the value of transmission.

Assigning Value to Reliability

In transmission investment valuation for grid planning, physical performance standards may be addressed in a number of ways. The simplest approach is to establish minimum physical performance requirements such as can be monitored through probability of load curtailment under specified contingencies, taking into account appropriate thermal and electrical security constraints. Such performance criteria may be applied to reliability of service over the entire system, individual load busses or areas, or both. If analysis indicates that physical performance will fall below the minimum level, the next step would be to determine the least-cost method for restoring performance. Depending on design of the valuation process, ranking of various options for meeting technical standards might be based only on their respective costs, or may also take into account their ability to provide additional value such as economic efficiency (reduced congestion). An integrated generation and transmission model developed for investment valuation provides determination of whether technical performance (e.g., reliability) standards are being met on both a system-wide and a location-specific basis, once the performance standards, applicable outage contingencies, and market scenarios have been defined.

Alternatively, and increasingly of interest under liberalization, it may be desirable to assign additional value to achievement of physical performance exceeding minimum standards. This can be addressed by the valuation methodology we demonstrate, based on measurements of transmission upgrades' operational effects. Unless this added value is converted to a financial measure, it creates valuation problems because there is no unambiguous way to balance this added non-financial value against investment costs or economic efficiency benefits, both of which are financially valued. This dilemma can be resolved by attaching a financial value to physical performance measures. For example, under Australia's "Regulatory Test" for evaluating regulated transmission investments, even the "market benefits" option for justifying transmission investments (as opposed to justification based on attaining physical performance standards) specifies that a financial cost be assigned for each projected MWh of unserved energy.

The methodology we propose for valuing physical performance ("reliability") benefits can readily accommodate assignment of specified financial values for each MWh of unserved energy. Of course, such values are somewhat problematic. The financial cost of a MWh of unserved energy is uncertain, and if it could be measured, it would be found to vary from place to place, time to time and customer to customer, and the 100th MWh of unserved energy in a given hour would likely be valued differently than the first MWh.

Value of Eliminating Unserved Energy

Transmission investments can have both economic efficiency impacts and impacts on reliability. We will address economic efficiency, but if we consider the reliability valuation problem alone, there is an objective solution that can be implemented using a modeling system such as UPLAN, a proprietary market model developed by LCG.[4] This solution is to value physical performance based on the amount of "reliability generation" investment that would need to be added to bring projected reliability up to a specified benchmark level. This "reliability generation" would generally be a low-cost peaking technology such as gas-fired combustion turbines. Thus, power system simulations can generate loss-of-load duration curves for each load node or region as part of the valuation process. From these curves it is possible to calculate the amount of additional "reliability generation" needed to keep expected load curtailment below the specified level, in terms of MWh per year, or in terms of maximum hourly loss-of-load MW not to be exceeded at a specified probability level.

A number of indices may be calculated to measure reliability on a dynamic basis. For example, the average unserved energy at each demand node measures the demand that would be interrupted due to shortages, transmission constraints or excessive loads. The standard deviation of the unserved energy gives a measure of the volatility of these occurrences. Other measures include the frequency of load interruptions, as well as the variability and the standard deviation of load interruptions. These numbers can be compared across cases reflecting a system before and after the addition of merchant plants, transmission reinforcements or transmission capacity additions.

Measuring Transmission's Effect on Economic Efficiency

In addition to the reliability (physical performance) benefits and losses, the basic transmission investment valuation methodology we illustrate considers consumer and producer surplus (economic efficiency).

It is essential to use realistic simulations of the transmission network's configuration and parameters, power flows over the network, and electrical and thermal constraints on those flows. This includes impacts of security constraints and contingencies on generator dispatch. These features are also required for valuation of physical (reliability) benefits as noted above. They contribute to realistic simulation of how transmission enhancements affect generator bidding, dispatch and resulting market prices at different locations, driving the valuation of economic efficiency benefits from transmission investments. As noted in Wolak et al's critique[5] of methods for assessing transmission expansion benefits in California, "..adding a realistic network model…is essential. …we also expect market outcomes to be very sensitive to the details of the assumed transmission network model."

Generation and transmission investment have a strong linkage, and may either compete with or complement each other, depending on whether the generation in question is near or far from loads. Since transmission investment can have a systematic impact on generation investment, alternative generation expansion scenarios should be linked rationally with transmission scenarios that do not run counter to the generators' competitive positioning. A major transmission upgrade may increase the profitability and likelihood of generation additions in a certain region, and so it does not make sense to pretend that the process of generation siting will not take the planned layout of the transmission network into consideration.

Congestion and Shadow Prices

One way of projecting the value of a transmission project where congestion exists is to start with the congestion cost or shadow price based on the difference between the nodal prices at two locations. This is based on certain assumptions about the effect of relieving the congestion. Assuming that the capacity of the transmission path connecting the two locations is increased, it is typically understood that the less expensive generation could supply more of the demand at the more expensive location. To the extent that the congestion is eliminated and the less expensive location has surplus generating capacity available, the more expensive location will benefit from the lower-priced generation, and the price should drop accordingly.

Taking this method of valuation at face value ignores a few caveats. First, just because congestion on a line is eliminated and the amount of surplus inexpensive generation is enough to completely displace the expensive generation does not mean that the prices will be equalized. This is because congestion and stability requirements of the system may exist elsewhere and preclude enough power from being sent to the high-priced location to reduce or eliminate the price differential. This is known as the "spring washer" effect. The second problem is that flows are not always in the direction of the high-priced location. They may in fact be in precisely the opposite direction, again due to operational constraints. The behavior of the network will be changed by whatever transmission projects are put in place, as well as by changing demand patterns and generation injection. This is why A/C-OPF modeling capabilities (rather than simplistic "transport" or DC models) are necessary for such valuation analyses. Buyers of power may benefit when congestion is reduced, and less efficient producers may earn less revenue, although the net change in benefits for either producer (if we pretend that there are two, an expensive and an inexpensive one) will in all probability not perfectly offset the change in benefits for the other. After all, the more expensive producer loses revenue because the price at which it sells energy is less competitive, while the consumer is able to buy at a more competitive price. The difference in operating efficiency weighs heavily in the determination of the overall societal benefit.

To obtain a realistic simulation of the configuration and properties of the transmission network, power flows over the network – and the electrical and thermal constraints on them - must be represented. In such network valuation and system simulations, it is necessary to incorporate security-constrained unit commitment, security-constrained economic dispatch, plus several combinations of contingencies and special protection schemes. In the absence of such a comprehensive procedure, a transmission system may be overbuilt for reliability purposes. Without a comprehensive model and procedure, valuations will be distorted and lead to sub-optimal infrastructure investments.

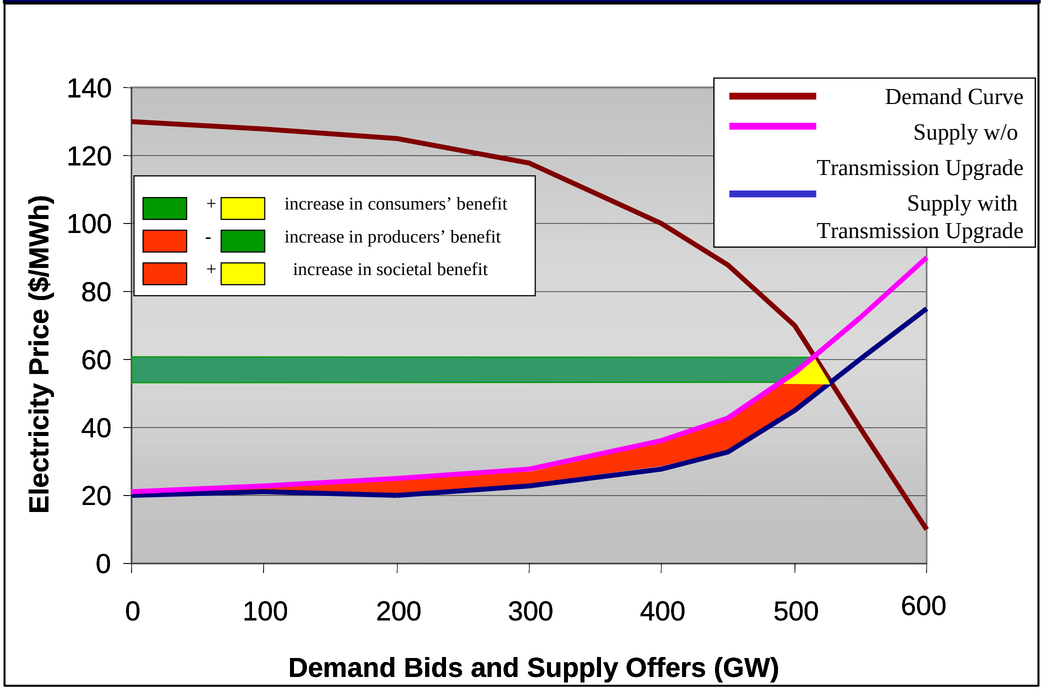
As mentioned, transmission investments cannot be assumed to take place against a static backdrop of fixed generation resources. Thus, the transmission valuation process ultimately needs to include some projection of generation investments and retirements based on rational financial profit and risk criteria, responsive to projected market conditions such as fuel and electricity prices. (In turn, the electricity prices would be affected by transmission expansion.) For example, one application of Australia's Regulatory Test to a proposed transmission project[6] examined several market scenarios, within which generation expansion projections were based on reserve margin or financial viability criteria, influenced by market conditions under that particular scenario.

In some situations the reliability or even economic value that would be provided by transmission investment could alternatively be provided by demand-side measures (load bidding or voluntary curtailment) or strategically located generation additions, including distributed generation. In some jurisdictions, cost-benefit analyses of regulated transmission investment are required to consider demand-side and/or local generation options to determine if transmission investment represents the most efficient solution. Demand-side and local generation options are not strictly part of a transmission investment valuation process. However, it may be useful or desirable that modeling tools used for transmission investment valuation be well-suited for evaluating these other options in a manner that allows them to be compared using the same criteria that are used with transmission investments.

Quantifying Societal Economic Benefits

We base our transmission investment valuation methodology on determination of societal benefits that the investment produces. The benefits of transmission investment or upgrades have to be evaluated in conjunction with changes in the generation system. Such investments increase the efficiency of the electricity system, lower the costs to the consumers, modify the amount and allocation of producers' profits, and make the system more reliable.

Figure 1. Illustration of Societal Benefits



The economic benefit of the project is the sum of the changes in consumer and producer surplus, as illustrated in Figure 1. For consumers, surplus is the difference between what they pay for electricity (market price or locational marginal price, LMP) and the amount they would be willing to pay (demand bid). For producers or generators, surplus is measured by their revenues less their production cost. Their revenues are calculated from the hourly equilibrium market prices or LMPs. The benefits or loss thereof associated with transmission investment are calculated for each hour by the change in social benefits (sum of producers' and consumers' surpluses) between the two cases (with and without investment). Figure 1 illustrates the demand curve and supply curves, one prior to the transmission upgrade and another following an upgrade. The decreased congestion and correspondingly lower cost of meeting energy demand represents the societal benefit of the upgrade. In a complete economic analysis of transmission investment, these gains would have to be compared to the investment costs over a project life of many years. To determine the temporal and spatial distribution of benefits to consumers and producers, it is essential to simulate the hourly generation dispatch as well as load flow.

In the following section, we present an example of a small system and illustrate the methodology for investment analysis for a 5-year period (2004-2008), measuring the change in social benefit resulting from the transmission investment. In making real investment decisions, this analysis has to be carried over for the entire grid using a generation/transmission model capable of simulating the market using, for example, the FERC Standard Market Design (SMD) and generation dispatch with SCUC/SCED. In the case of a long-term simulation for a full representation of the network, we would also incorporate an optimal plan for future investment in generation to meet the projected load growth for the planning horizon (10-20 years), to the extent that new installations were economically viable.

Under a market-driven restructuring, the generation capacity decision and the transmission capacity decision are separate business decisions. Yet, they remain inter-dependent. The potential investor in additional generation capacity is interested in the future energy prices at a prospective location, which are likely to be influenced by the future state of the transmission grid. In turn, the need for transmission and the profit opportunities for transmission reinforcements are determined in large part by future generation expansion. We would like to emphasize that the impact of a transmission upgrade is distributed throughout the entire grid and all users benefit.

Simulation and Results

As stated, we used the UPLAN Network Power Model with SCUC/SCED to determine the actual hourly dispatch of generators and load flows. The simulation provided the following information:

- Location and duration of any unserved energy which can be used as an index for reliability and optimal generation expansion for both cases
- Security constrained unit commitment and hourly economic operation of the generators
- LMP-based electricity prices, producers' revenues and consumers' costs
- Producers' generating costs, including fixed and variable O&M
- AC Load flow and congestion costs

In the base case, congestion existed along a transmission path, while in the upgrade case, congestion was reduced by raising the capacity of the line, in effect performing a transmission upgrade. Besides this single difference, the same static set of values for input variables such as demand and fuel prices was used for both cases. This pair of cases showed the transmission upgrade's financial benefits to the consumers, producers and society. Comparing the net benefits with the cost of upgrade, which we do not account for here, provides the basis for a comprehensive cost-benefit analysis. In the following tables we summarize the characteristics of the sample system.

Table 1. Features of Sample System

The Sample System	
Number of Generators	6
Number of Buses	6
Number of Transmission Lines	7
Peak System Demand (MW)	1,700

The main features of the example system are given in Table 1, while the characteristics of the generating resources appear in Table 2. The weekly peak loads for 2004 are presented in Figure 1. The characteristics of the transmission lines are presented in Table 3, while the layout of the network, including the locations of the generating units, is shown in Figure 2.

We performed simulations of the year 2004 for the base case and for the line-upgrade case, both based on the most likely set of conditions concerning demand. Key results and the differences between those results from each of these cases will be presented first. We also performed a series of simulations for each of the years 2004 through 2008, to determine by how much the benefits from our targeted transmission investment may vary. This contrasted with the first 2004 simulation, in which a single demand forecast, or single-point forecast, was used in one simulation. For 2004 through 2008, Monte Carlo sampling was used to develop a range of possible scenarios, in which the demand level was randomly sampled from a probability distribution. The probability distribution reflected the uncertainty of future demand. Given that the same seed was used to generate the random variation in demand in both the base case and the case incorporating the line upgrade, we then were able to compare the probabilistic variation in the benefits, based entirely upon the line upgrade and on no other changes. We first discuss the results from the original 2004 simulation, which assume that the single-point demand forecast, the most likely case, is actually observed. We then review the five-year results, which reflect the uncertainty with respect to demand.

Figure 2. Weekly System Peak Load, 2004

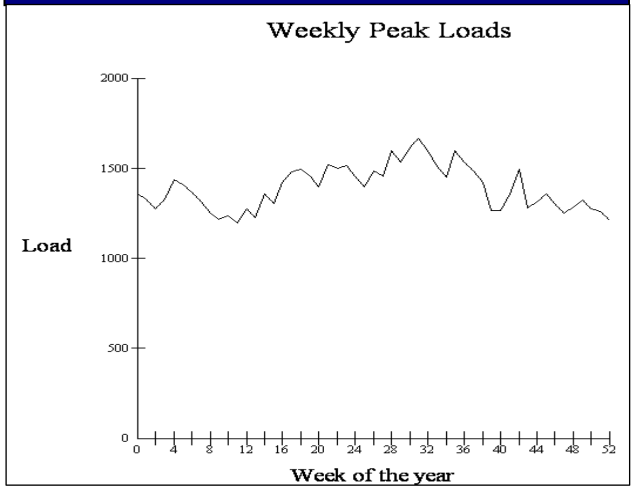


Table 2. Generating Resources

Unit	Capacity (MW)	Fuel	Avg. Var. Cost ($/MWh)	Injection Bus	Zone
Gen1	500	Gas	42	C	1
Gen2	200	Coal	32	E	1
Gen3	300	Gas	35	E	1
Gen4	300	Gas	33	A	1
Gen5	350	Gas	40	D	2
Gen6	200	Oil	50	F	2

Base and Transmission Upgrade Cases, Most Likely 2004 Results

In the base case covering 2004, the demand levels at each bus as well as the line and generating capacities were such that a line, E2D, was heavily congested, based on its existing capacity of 200 MW (see Figure 3). The line B2E also experienced congestion in the base case. Thus busses D and F, in Zone 2, were unable to obtain energy from less expensive generating resources in Zone 1, which had spare capacity. Generating units on the congested side of the line, 5 and 6, had relatively higher costs than the other units, and because of the congestion, the busses in Zone 2 where units 5 and 6 were situated, D and F, experienced higher locational marginal prices (LMPs) than would have been expected otherwise.

The generating unit output at each bus for all of 2004 is presented in Figure 3, for both the base case and the upgrade case. There were also 6.3 GWh of unserved energy during the year in the base case, during 183 hours, on 31 separate days, all at busses D and F.

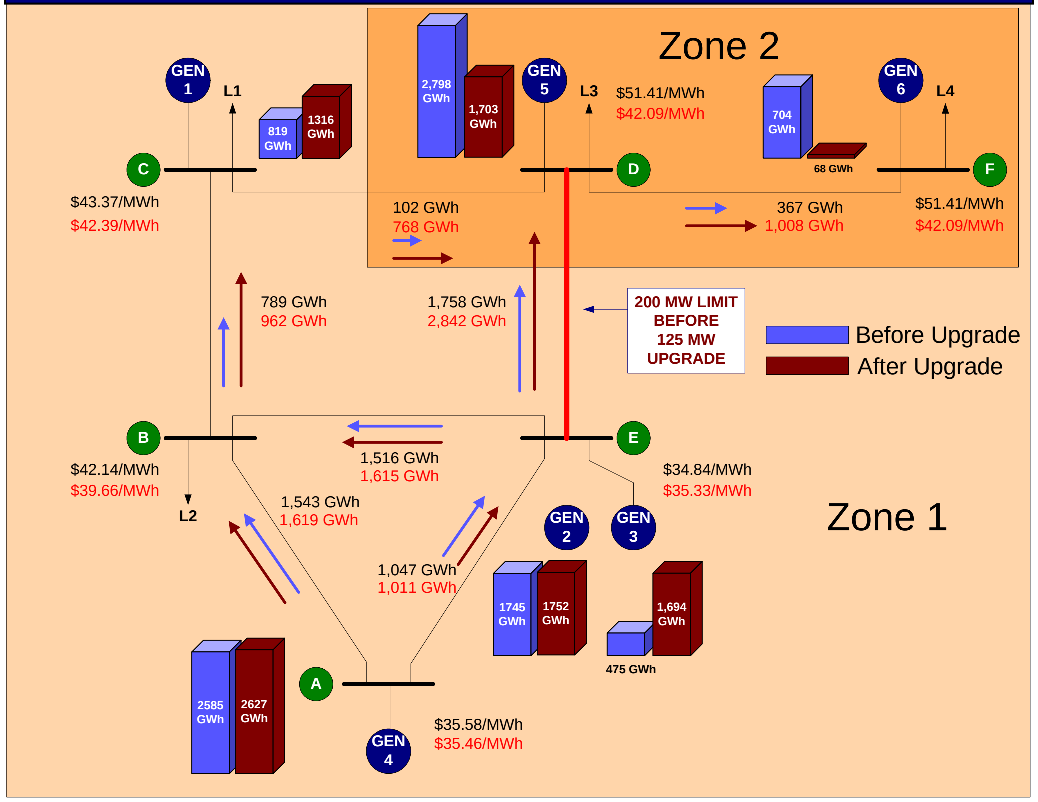
Table 3. Transmission Network

The Transmission Network Characteristics of the Example System

Line Name	Transmission Capacity (MW)	Transmission Loss (%)	Resistance (pu)	Reactance (pu)
A2B	197	0.561	0.0025	0.0141
C2B	137	1.701	0.0010	0.0054
C2D	195	0.516	0.0030	0.0149
E2D	200 existing, 325 with upgrade	0.945	0.0020	0.0125
E2A	154	0.135	0.0006	0.0032
D2F	174	1.751	0.0060	0.0320
B2E	199	0.647	0.0020	0.0120

For the upgrade case, we simulated the system by adding 125 MW to line E2D, for a new capacity of 325 MW (this is summarized in Table 3). With the line upgrade, and with all other conditions remaining the same, all the unserved energy was eliminated, and the 2004 annual peak LMP at bus D was reduced by $9.31/MWh, to $42.09/MWh. The average annual peak price for each node in both the base case and upgrade case is shown at the nodes themselves in Figure 3.

Figure 3. Transmission Flows Before & After Upgrade for the Year 2004



The changes in the generator performance for 2004 between the base case and the upgrade case are shown in Table 4. The annual load flows on each line before and after the upgrade are shown in Figure 3. In addition, the output of each generator for both cases appears in the form of columns of variable height at the generator's location. Note that the annual flow on line E2D is roughly 50% greater with the upgrade, while the output of generating unit 5 has decreased by more than one-third. The unit's net income is lower by 80%. As might be expected, more of the demand is being served by generating units in the less expensive Zone 1, while the prices in Zone 2 are lower. Because the results are produced on an hourly basis, it is possible to quantify with relative precision by how much consumer payments and producer incomes have been affected following the line upgrade. Table 4 also shows the average revenue per MWh, which is generally lower, contributing to a drop in net income for all units with the exception of unit 2, which experienced a rise in the average revenue and net income.

Table 4. Generator Unit Performance With and Without transmission Upgrade in 2004, Single Simulation with Most Likely Results

Unit	Energy Production (GWh)			Net Income ($000's)			Average Revenue ($/MWh)		
	Before Upgrade	After Upgrade	Change	Before Upgrade	After Upgrade	Change	Before	After	Change
Gen1	820	1,317	(497)	9,032	5	(9,027)	53.0	42.0	(11.0)
Gen2	1,746	1,752	(6)	4,546	5,256	710	34.6	35.0	0.4
Gen3	475	1,694	(1,219)	0	0	0	35.0	35.0	0.0
Gen4	2,585	2,628	(43)	5,819	5,434	(385)	35.3	35.0	(0.3)
Gen5	2,799	1,703	1,096	27,058	4,651	(22,407)	49.7	42.7	(7.0)
Gen6	704	68	636	4,113	-	(4,113)	55.8	50.0	(5.8)

High-cost generating units 5 and 6, on the previously congested side of line E2D (Zone 2), produced less energy when the upgrade was installed. Correspondingly, Zone 1 units 1 through 4 produced more. Units 1 and 3 in particular increased their output the most, displacing the generation from the less competitive units 5 and 6. While unit 1 increased its output, its net income decreased and became nearly zero after the upgrade, due to the lower price it was paid for its output. Unit 2, which produced at nearly the same level in both cases, improved its net income by $710,000, because of the rise in prices that took place in the more competitive Zone 1, as surplus capacity shrank due to exports. Unit 5 had nearly an 83% drop in its net income, yet still had positive net income of $4,651,000. This unit, which was one of the least efficient as seen by its high variable cost, was no longer protected by the congestion, following the line upgrade. As a result for the illustrated year of 2004, the total generation of units 1 and unit 3 increased and replaced the high-cost generation by units 5 and 6, and the net income increased for only one unit (unit 2).

Results from 2004-2008 With and Without Transmission Upgrade, Using Variable Demand Based on Monte Carlo Random Sampling

We now discuss the results obtained by running a series of simulations, each incorporating a particular level of randomly determined demand. For future years, 2005-2008, we assumed that the load shapes and generation characteristics remained essentially the same. However, we assumed that the basic, most likely load forecast would show demand increasing at an annual rate of 1.5%. While the resulting forecast provided the highest-probability point of each year's probability distribution for peak demand, each simulation was based on random sampling from a distribution.

We also assumed the installation of two small generating units at bus D, one in 2006 and one in 2008. This was determined by the fact that the location provided economic justification for such an installation. The installation was assumed in not only the base case but the line-upgrade case as well, as we wished to maintain all assumptions for the respective simulations, other than the upgrade itself, as being identical.

One-hundred simulations were conducted for each year, providing an essentially stable distribution of outcomes. Out of these simulations, average or expected values of consumer, producer, and societal benefits were determined for each year. The resulting nominal consumers' benefits for these years are shown in Table 6 and range from $56.80 - $80.90 million per year, with a net present value of $274.07 million based on the entire 5-year period. Since the market price dropped, the generators on the congested side of the transmission line no longer received higher electricity prices, and their benefits (due to a loss of revenue, slightly offset by lower operating costs) dropped by $217.10 million over the 5-year period. The loss of revenues was borne mostly by the inefficient generators on the congested side of the system. However, the overall benefits to both consumers and producers for the period are put at a net present value of $56.97 million, and can be used as the upper bound for transmission investment.

In Table 5 and 6 we summarize the mean results of the simulations of the illustrative cases with and without the transmission upgrade. Table 5 shows the Zone 2 electricity prices and corresponding decreases due to the upgrade across all hours, by $8.22/MWh in 2004, and by more in succeeding years, up to $10.69/MWh for 2008. As a result of the upgrade, the market price of electricity in Zone 2 dropped and the customers benefited.

It is notable that because of the reduced congestion, there was a smaller difference between peak and off-peak prices in the upgrade case as compared with the peak price differential of the base case, meaning that with less congestion, hourly price volatility was reduced.

The cost of the proxy unserved energy unit was determined by calculating the required revenues to make the proxy unit whole for both capital and operating costs. Incidentally, the proxy unit operated for 15 hours for the upgrade case compared to an average 290 hours of operation every year for the base case.

Table 5. Zone 2 Electricity Prices With and Without Transmission Upgrade, Based on Variable Demand Forecast ($/MWh), 2004-2008

Year	Without Transmission Upgrades (a)			With Transmission Upgrades (b)			Price Difference (a-b)		
	Off-Peak Avg	On-Peak Avg	All Hours	Off-Peak Avg	On-Peak Avg	All Hours	Off-Peak Avg	On-Peak Avg	All Hours
2004	48.01	52.40	49.80	41.22	41.96	41.58	6.79	10.44	8.22
2005	50.16	54.88	52.48	42.32	43.21	42.59	7.84	11.67	9.89
2006	50.76	55.22	52.59	43.44	44.25	43.59	7.32	10.97	9.00
2007	52.81	57.77	54.98	44.55	45.58	45.05	8.26	12.19	9.93
2008	54.16	59.06	56.78	45.72	46.66	46.09	8.44	12.40	10.69

The results at various levels of demand show that while the change in both consumer surplus and producer surplus was affected noticeably by demand, the overall societal benefit was remarkably stable. The production cost savings depends on the altered dispatch of the units, and the operating characteristics of the more efficient units. These units ran more because of the transmission upgrade and the corresponding decrease in congestion.

In Table 6, we show the nominal change in consumer, producer and societal benefits (consumer and producer benefits combined) averaged over the paired differences of one-hundred simulations performed for each case for each of the five years, and the present value of the yearly amounts, discounted by 8% to 2003 dollar terms.

Table 6. Present Value in 2003 of Annual Producer and Consumer Benefits at 8% Discount Factor for 2004-2008 (in $ Millions)

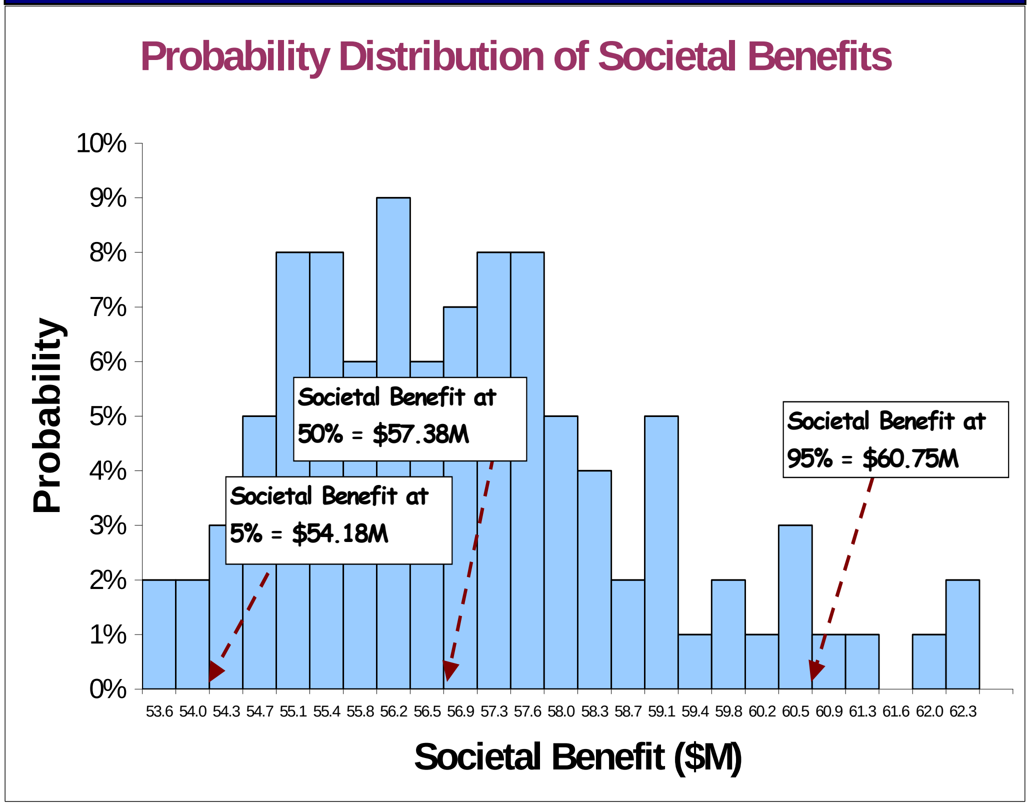
Consumers', Producers' and Societal Benefits from 2004-2008 (Nominal $ Millions, except for NPV)

Year	Consumers Benefits ($M)	Producers Benefits ($M)	Societal Benefits ($M)
2004	56.80	(44.47)	12.33
2005	67.46	(54.02)	13.44
2006	66.60	(52.01)	14.59.
2007	75.79	(60.05)	15.74
2008	80.90	(64.92)	15.98
NPV (2003) of Sum @ 8%	274.07	(217.10)	56.97

For some of the simulated cases, there are unserved energy due to high demand. For comparison purpose, we added a proxy unit to eliminate the unserved energy in all cases.

The distribution of the societal benefit over the series of simulations showed the societal benefit at the 50th percentile was $57.38 million and ranged from $54.18 to $60.75 million dollars at 5% and 95% levels. The entire range of societal benefits from the simulations is indicated in a percentage frequency distribution in Figure 4. Note that the annual congestion cost is a poor estimator of consumer savings. The savings for consumers based purely on annual congestion has understated the value of the transmission line. Based on the previous discussion, of course, the consumers' gain is also a loss in terms of producer surplus. We determined probabilistically that the overall societal benefit of the transmission upgrade in 2004 based on uncertain demand has an expected value of $12.33 million. According to congestion cost output from the model, based on locational price differentials across all hours, the two cases based on the single most likely demand forecast show a congestion cost reduction of $15.158 million, which is favorable for consumers and unfavorable for less efficient producers. We see that in this example, using congestion cost as a valuation method for the upgrade yields a higher figure than does the measurement of change in social benefit ($15 million as opposed to $12 million). The benefit to consumers and the loss to producers in isolation exceeded both valuation measures and showed the magnitude of the redistributive effect that could be expected. Thus, if we are to base our valuation of a transmission project on congestion cost alone, it must be made clear that congestion costs may not fully represent the effect a transmission project will have on a given set of market participants, or overstate the overall benefit to be realized.

Figure 4. Probability Distribution of Societal Benefit from Line Upgrade, 2004-2008, 2003 Net Present Value ($ Millions)



As discussed, transmission and generation investments can have significant impacts on one another. Therefore, the two must be considered together for long-term planning purposes, not in isolation. As stated before, we consider one aspect of the cost-benefit analysis. We do not try to assign a specific value to reducing unserved energy, and neither do we account for the method of financing or the time-frame for recovery of expenditures. Insofar as it is desirable for funding to come from those who are expected to benefit from particular projects, it is important to understand the way in which economic surplus for different participants is likely to be affected, and the degree to which fundamental variables will affect the incremental cash flow relative to other transmission projects, generation projects, non-infrastructure market-oriented programs, or relative to a situation in which investments are delayed or not undertaken.

Dr. Rajat Deb is the founding president of LCG Consulting, Los Altos, California. He has more than 30 years experience in energy industry and academia and has contributed extensively to both the theory and practice in the energy field. Mr. Alexey Tretyakov from Progressor of Moscow, Dr. Keith White, Dr. Pushkar Wagle, Sidart Deb and Nick Brown of LCG have contributed to the model simulation and provided valuable comments and suggestions for this paper. Dr. Deb can be reached at deb@energyonline.com or 650-962-9670.

---

[1] In testimony before the House Committee on Energy and Commerce, David Owens, Executive Vice-President, Edison Electric Institute, noted that NERC has put the increase in the volume of "actual transmission transactions" at 400 percent in four years. Accordingly, Owens said, NERC found that the amount of uncompleted transactions due to congestion as rising from roughly 300 in 1998 to nearly 1,500 in 2002.

[2] Huntoon, Steve & Metzner, Alexandra, "The Myth of the Transmission Deficit," Public Utilities Fortnightly, November 1, 2003.

[3] For example, PJM's planning protocols would require regulated transmission investment for the economic purpose of reducing high congestion costs, where such investment is calculated to be cost-effective and is not provided by the market. In contrast, NYISO has established procedures for awarding long-term transmission rights to developers of merchant transmission, but not for mandating transmission investments for economic efficiency purposes.

[4] UPLAN-NPM is a multi-commodity, multi-area regional electricity model using optimal AC/DC power flow and market algorithms to analyze the economic and physical impacts of competition in a regional power market. It simulates markets and bidding for energy and ancillary services using arbitrage opportunities across markets for bidding behavior, and iteratively determines the Nash equilibrium between producers aiming to maximize their profits, and consumers, whose objective it is to minimize their costs. UPLAN simulates the network operations, as well as the location of demand and generating resources, and the modeling of the interaction among injections, withdrawals, security-constrained economic dispatch and unit commitment (SCED and SCUC), and the impact of transmission investments on impedances and on thermal and electrical constraints for network elements. It does so using AC optimal power flow, and can incorporate thousands of buses. A simulation that is geographically limited or restricted to a small number of busses relative to the actual number within the area represented will inevitably be less accurate.

[5] See Frank Wolak, Chairman, Brad Barber, Member, James Bushnell, Member, Benjamin Hobbs, Member, Market Surveillance Committee of the California ISO, "Comments on the London Economics Methodology for Assessing the Benefits of Transmission Expansion", October 7, 2003. Also see Peter Dobney, Chairman, Energy Users Association of Australia, "Market Review and Competition Benefits Test Forum", July 28, 2003, and see "Competition Benefits and the ACCC Regulatory Test", Drayton Analytics, July 28, 2003.

[6] "Application of the ACCC Regulatory Test to SNI," op cit.