Transmission Planning Today: A Challenging Undertaking

Ramón Nadira, Ricardo R. Austria, Carlos A. Dortolina, and Miguel A. Avila

Abstract. Planning electric power transmission systems today is a challenging undertaking, no matter what structure the electricity sector is organized under. We present the reasons as to why we believe this to be the case, discuss the issues relevant to transmission planning today, argue that traditional planning assumptions are no longer justified, and propose a methodology that explicitly accounts for the uncertainties and considerations relevant to today's transmission systems. We then show the results of applying this methodology to a transmission system in North America.

I. INTRODUCTION

In general, planning electricity transmission systems is hard to do, no matter if the electricity industry is bundled or unbundled, in developed or developing countries, with or without private sector participation, and so on. We believe this to be the case, in part, for a number of structural considerations which we discuss next.

First, there are the laws of *physics*[1], which apply in a nondiscriminatory fashion to all[2]. For one thing, a power system is an integrated "energy-conversion machine"[3], and as such, its various components (i.e., generation, transmission, and distribution) are strongly coupled from a functional viewpoint. For example, transmission transfer capability is a function of the generation dispatch as well as of the location and size of the load demand. Further, transmission systems do not behave – and therefore cannot be properly modeled - as transportation networks[4]; power flows in a transmission system do not follow contract paths. The laws of physics and the non-linear response of system controls are important.

On top of this, since system conditions are continuously changing, the requirements on the transmission grid also change continuously. This places a significant burden on the methodologies and tools used to plan and simulate the system.

Then, there are the ever so important *economic* considerations. It is quite challenging to calculate the costs and benefits associated with a transmission plan, in part because it is hard to functionally separate generation from transmission from distribution. Further, except for DC ties and in the simplest of cases (such as radial systems), it is incorrect to attempt to calculate the costs and benefits of individual transmission projects. These costs and benefits accrue to the entire plan and are virtually impossible to allocate to the individual projects.

In the U.S., regulated rates of return on transmission infrastructure projects may often be too low to attract the investment needed to finance and build new transmission facilities given the underlying uncertainties[5]; thus, other financial incentives are also needed (e.g., innovative rate approaches)[6]. As a result, even the most robust of plans, may not be implemented as designed because of a lack of interest from developers.

Finally, there are *regulatory* considerations to contend with. In today's systems, obtaining the necessary permits to build transmission infrastructure projects involves a prolonged process, which often encounters opposition from a number of the stakeholders, including consumer groups[7]. Again, because of this regulatory uncertainty, what in the surface may look like a robust plan may not be implemented as designed because of such opposition[8].

Traditionally, transmission systems have been planned under a number of fundamental premises, including the following. First, the location and size of future generating power stations are assumed to be known with relative certainty. Transmission planning is traditionally subordinate to generation planning and, in many cases, completely separated from it. Second, the system is simulated only for a few selected operating conditions. Third, transmission plans have been traditionally justified from a technical - rather than economic - point of view. Expansion philosophy was typically as follows: "Define service quality standards and expand the transmission system to satisfy these standards at minimum cost." Therefore, complete benefits associated with the transmission systems are rarely quantified.

The above assumptions, which certainly simplify the problem, were relatively valid for a vertically-integrated industry, and resulted in power systems that performed very well for many decades. In fact, in the words of the Federal Energy Regulatory Commission (FERC) of the U.S. "the degree to which we take this highly complex, highly interconnected machine for granted is a tribute to the past performance of the system."[9]

However, in the opinion of some, the 2003 blackout event in the United States and Canada has exposed the vulnerabilities of the transmission system. In fact, even President Bush appears to have concluded that the delivery system is "old and antiquated". Others have called for the overhaul of the transmission planning methodologies. We find it rather interesting that people appear to have assigned early and exclusive blame to the transmission system, when, as mentioned above, generation, transmission, and distribution are strongly coupled from a functional viewpoint.

The above notwithstanding, we recognize that worldwide, the industry is experiencing deep changes with regards to its structure (i.e., vertical separation of generation, transmission, and distribution companies), to its ownership (i.e., participation of privates in transmission), and to its regulatory mechanisms (e.g., establishment of autonomous regulatory entities)[10]. These changes are having a significant impact in the way transmission networks have to be planned and operated.

In practice, this means that a number of additional uncertainties must be explicitly modeled in the transmission planning process. For example, competition in generation results in major uncertainties with regards to location and size of future generating power stations. Additionally, transmission organizations will have to justify their expansion programs from a technical, economical and regulatory perspective.

In this paper, we present a transmission planning approach that is not based on the traditional fundamental premises. The approach has been proven in two real-world applications, one in North America and the other in Central America. The paper briefly describes one of these applications, with emphasis on the advantages, disadvantages, and difficulties associated with the initial application of the planning approach.

II. PLANNING METHODOLOGY

Here, we apply the planning under uncertainty methodology known as trade-off risk (or TOR, extensively reported in the literature[11]), which has been proven to be very effective in multi-objective optimization problems such as transmission planning. With multiple conflicting objectives, the traditional concept of optimization is of limited use since there is usually no plan which is "best" in terms of all of the objectives or attributes of concern.

When a problem has multiple objectives or attributes, there is usually no single solution which simultaneously optimizes all of them. The best that can be hoped for is a compromise which represents a reasonable trade off among the attributes. In Figure 1, where the objective is to minimize both unserved energy and the cost of electricity, the interior plans are inferior to, or dominated by, the plans on the trade-off curve (the continuous curve in Figure 1). The plans near the knee of the trade-off curve are the most interesting. They make up the **decision set** for particular materializations of future conditions. These concepts extend mathematically (but not necessarily graphically) to problems with more attributes, and with several different types of conflict.

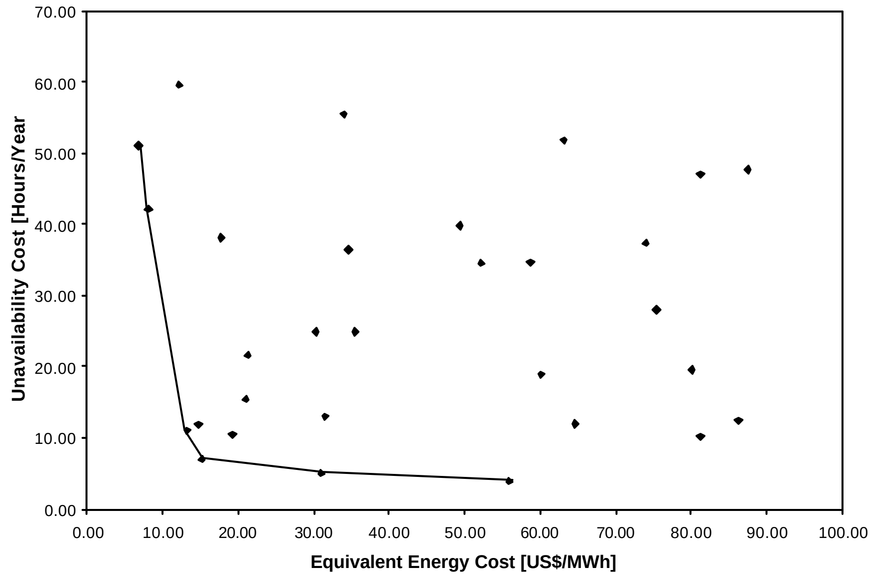

Figure 1. Example of Trade-Off Curve.

A rigorous cost/benefit analysis of the candidate plans is performed as part of the TOR methodology as applied in this paper to transmission planning. The analysis attempts to answer the following seldom asked questions:

1. Are transmission plans economically feasible?
2. If so, what is the return on investment?

In addition, the TOR approach takes explicit account of:

- **Relevant Uncertainties**[12]: - such as those associated with the location and size of new power generating stations - to produce robust transmission plans with regards to these uncertainties[13].
- **Reliability Criteria**: transmission plans are a direct function of the adopted reliability criteria[14] (incidentally, congestion is too[15]) For example, the cost of the plan is directly related to the reliability criteria used (and congestion costs are too!)

  In many developed countries, the reliability criterion often used is that known as "n-1." According to this criterion, the transmission system will have enough capacity to withstand the loss of a single power system component without the need to shed load and with all remaining equipment continuing to operate within safe limits. The n-1 criterion is deterministic (i.e., it does not account explicitly for the probability of the single contingency occurring), and as such it is rather stringent. In fact, the system is planned to withstand the worst contingency at the worst possible moment. Other criteria, such as those of the probabilistic type, have received some attention, but are not widely used[16].

  Developing countries generally adopt less stringent criteria, which obviously result in less expensive designs. An often used criterion is for the system to withstand single contingencies without widespread loss of supply, islanding, voltage collapse or cascading outages, with no operator intervention.
- **When is Additional Transmission Needed?** A complex issue is to determine when a transmission system has reached "saturation", and as a result, new transmission is needed. Figure 2 illustrates the situation.

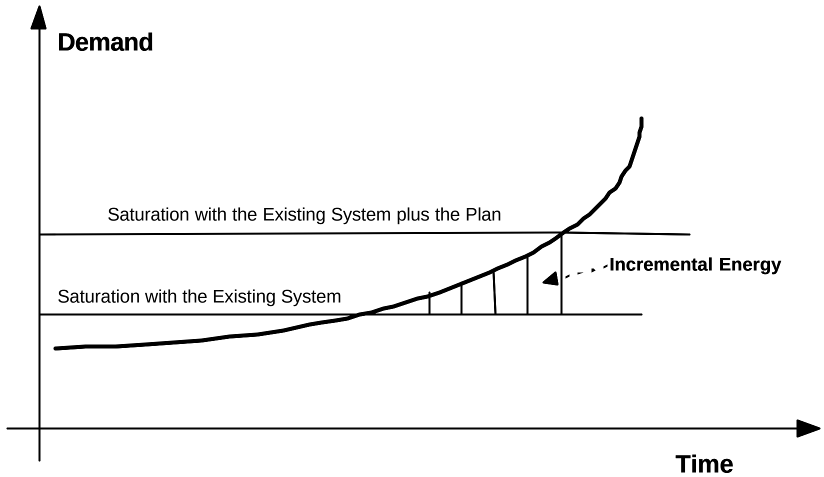

Figure 2. Incremental Energy.

A transmission system reaches saturation when it is no longer able to perform to the reliability it was designed to provide. Determining when this is the case is rather complicated, and is a function of the generation expansion plans and the relative load demand growth in the various regions of the system. Incidentally, the Incremental Energy is simply the area under the load demand curve which can be served as a result of expanding the transmission system (i.e., with and without the plan).

One way of determining the saturation demand for a future year "i" is as follows:

1. Verify that the system meets the standing reliability criteria for year "0".
2. Test the reliability criteria for all system areas for year "i". If there is an area where the criteria are not satisfied, reduce the load in that area until the standing criteria is satisfied. The saturation demand in that area will be the maximum load that can be supplied without violation of the criteria. Once it is necessary to reduce load in an area to satisfy the reliability criteria, the saturation demand in that area is set at the saturation demand value.
3. Repeat above step until the saturation demand in all areas has been determined.

Alternative methods based on optimization techniques have also been proposed[17].

III. OPTIONS, UNCERTAINTIES, AND SCENARIOS

Key to the successful application of TOR is the correct definition of **options** (choices or possible decisions available to the planner), **uncertainties** (quantities or events which are beyond the decision makers' foreknowledge or control), and **scenarios**, as shown in Figure 3. A **plan** is a set of specified options. A **future** is a set of materializations of the modeled uncertainties. A scenario is a combination of a single plan with a single future. **Attributes** are measures of the goodness of a particular scenario (more precisely, they are measures of the goodness of a particular plan, for a given future[18]).

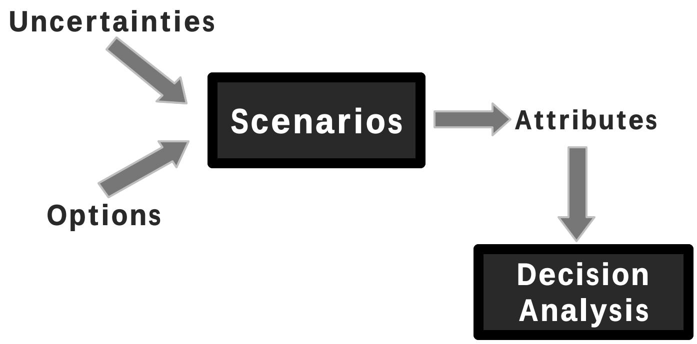

Figure 3. Proposed Methodology.

Options include the alternatives traditionally available to the planners, such as building additional transmission lines and/or substations, as well as upgrading circuits, expanding substations, etc.

Traditional uncertainties, such as load growth, O&M costs, capital requirements, and availability of transmission facilities, among others, clearly have a significant impact on the transmission planning process. Arguably, however, uncertainties related to the structure (i.e., "structural" uncertainties) of the energy sector may have the largest potential impact. Typically, these uncertainties may be modeled by the use of unknown-but-bounded models (see below).

For each scenario, the proposed methodology selects alternative transmission plans which, for the uncertainties modeled and in the long run, are least-cost and meet the standing reliability criteria. Several tools (e.g., load flow and transient stability programs) may be used to develop the alternative transmission plans for each scenario, for a given year. The typical planning period is ten years, considering the significant uncertainties associated with the very long term (25-30 years) and the desire to evaluate transmission projects for a significant period of their useful life. A ten-year period is also consistent with recent experiences in countries such as Thailand, the Philippines, Mexico, Guatemala, India, and China.

The least cost plans must be developed for intermediate staging years in order to identify the sequence (or priority) of the individual projects for each plan. For each staging year, the plan must also meet reliability criteria.

Finally, although the methodology is able to accommodate a large number of options, uncertainties, and scenarios, it is often necessary to narrow down the alternatives to a number small enough in order to be able to produce - in a reasonable amount of time - a solution that: (1) captures the important issues (i.e., produces useful results), (2) represents a wide range of possibilities, and (3) aids in the decision making process. For example, one possibility is to select only one transmission plan (the minimum cost plan) for each scenario.

IV. CALCULATION OF ATTRIBUTES

The attributes of the transmission plans can be naturally segregated into two categories: costs and benefits. These can in turn be used to calculate economic indicators, such as cost/benefit ratios or internal rates of return (IRR).

The costs are:

- *Capital Expenditures (CapEx)*. These are the estimated costs of the expansion solutions, and include all of the Engineering, Procurement and Construction (EPC) costs associated with these solutions.
- *Operation and Maintenance Expenditures (OpEx)*.
- *Upstream Incremental Costs*. These are the costs associated with the wholesale purchase of energy by the transmission system, generally valued at the marginal cost of such purchases.
- *Downstream Incremental Costs*. These are the costs associated with the delivery of power from the transmission system to the end-user (i.e., sub-transmission, distribution, and commercialization costs).

The upstream and downstream incremental costs are designed to account for the fact that all of the benefits, as calculated below, do not accrue exclusively to the transmission system.

The benefits are classified according to whether they are:

- *Associated with the Incremental Energy.*
- *Associated with Reliability Improvements*; and
- *Associated with Operations* (i.e., loss reduction and optimized dispatch).

Benefits associated with the Incremental Energy include the additional load demand than can be served as a result of the transmission system expansion, valued at the average tariff level, as well as the consumer surplus, calculated as follows (see Figure 4):

$$\textbf{Consumer Surplus} \approx (\Delta P \times \Delta Q)/2 = P(\Delta Q)^2/(2\varepsilon Q) \quad (1)$$

where ε the price elasticity, and Q is corresponds to the saturation demand without the plan plus the incremental demand.

Benefits associated with reliability improvements are generally difficult to quantify since a number of quality of service indicators can be applied. These indicators may include, among others, frequency and duration of outages, and energy-not-served (ENS). When using ENS as the indicator, the reduction in unserved energy, valued at the interruption cost (a system-dependent quantity), corresponds to the plan's reliability benefits. ENS was the indicator used to measure reliability improvements in the cases described later in the paper. This is common practice in many countries, as interruption costs associated with the ENS are regularly estimated in connection with generation expansion studies.

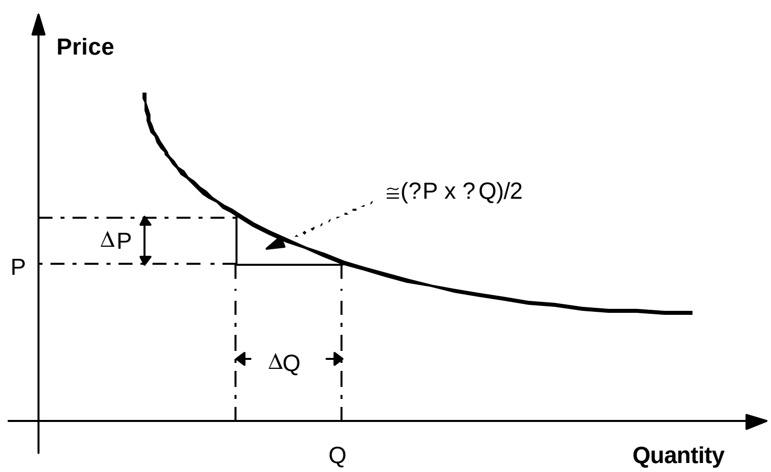

Figure 4. Consumer Surplus.

Reliability benefits should be estimated for the corresponding expected demand conditions subtracting the associated incremental energy under two scenarios: with and without the plan. Incremental energy is subtracted in order to compare scenarios where demand is supplied under comparable reliability conditions.

Similarly, benefits associated with the reduction of losses and optimum dispatch should be valued according to the difference in the corresponding costs with and without the plan. Loss reduction is a classical benefit calculated as the reduction in system losses brought about by the expanded transmission system. It is quantified in terms of the savings in generation costs.

On the other hand, the optimization of generation dispatch benefit is associated with the reduction in system marginal generation costs as a result of the expanded transmission system. This benefit is calculated by means of a security constrained economic dispatch (or Optimal Power Flow) program for a number of representative operating conditions, and is quantified in terms the of monetary units saved as a result of the expanded system.

V. DECISION ANALYSIS

In the best of cases, a single plan will be robust, that is, it will be the plan that one would chose no matter how uncertainties were to materialize. Clearly, such a situation is not very common.

Thus, in the majority of the cases, it is necessary to use hedging strategies with the goal of mitigating the possible impact caused by the modeled uncertainties[19]. In particular, it may be possible to create a hedge by adopting combination plans. These would contain options that could be canceled or activated in the future, if possible, if the uncertainties materialized in an adverse way[20].

VII. CASE STUDY

This section describes recent experience with the application of the planning approach in a North American country[21]. A key aspect of the application of the proposed methodology was the explicit consideration of the uncertainty associated with the location and size of future generation. There were, at least, two sources for this uncertainty, as follows:

1. assuming the existence of a *normative* generation expansion plan, it is possible that some of the premises used to develop this plan will cease to be valid at some point in time. For example, if the plan includes a large number of gas-fired combined-cycle power stations, it is possible that changes in the actual vs. assumed availability of that fuel in certain areas of the system will introduce important uncertainties; and
2. assuming the existence of an *indicative* generation expansion plan (e.g., with the participation of privates), it is evident that the precise development of such future generation is rather uncertain.

The uncertainty associated with the development of future generation was modeled via unknown-but-bounded models, i.e.,:

1. *"Status quo" scenario*: simulated the continuous application of normative planning.
2. *"Restructured" scenario*: assumes a restructured energy sector, in which the generation is developed without any normative plan.

Although it is recognized that the electric sector's real evolution may not strictly follow any of these two scenarios, these extreme cases probably cover most possibilities. Furthermore, modeling such extreme scenarios enables the separation of those projects that are affected by possible sector restructuring from those that are not, which allows identifying robust transmission projects.

The case study involved the development of ten generation scenarios (four status quo and six restructured) based on assumptions that have a material effect on the location of future power generating stations, such the availability of natural gas in some regions of the country. Additionally, the postulated scenarios were designed to represent a wide range of transmission system operating conditions. From these ten scenarios, a total of eight were selected to develop detailed transmission plans (three status quo and five restructured). Two generation scenarios were dropped since they demanded similar transmission reinforcements than at least one of the eight finally chosen.

Fifteen (15) transmission plans were then developed, to meet system requirements for the horizon year (10 years into the future) for the various scenarios. On the average, about two distinct transmission plans were developed for each scenario. In addition, of the eight scenarios, only six exhibited materially different transmission requirements. Only one transmission plan (the least-cost plan) was selected for each of the six remaining scenarios. These six transmission plans were staged.

Decision analysis revealed that a robust transmission plan existed for the first four years of the period (all projects turned out to be similar for all plans). On the other hand, the transmission projects for the following years were found to be different.

The results of the economic analysis revealed the following (using a 12% discount rate and a useful life of 30 years for each project):

1. As shown in Figure 5, incremental energy sales and increased reliability comprised about 80% of the total benefits associated with the transmission plans. Consumer surplus, on the other hand, accounted only for a small percentage of the benefits.
2. Taking into account all benefits and costs associated with the transmission plan, the IRR was significantly above 12% (i.e., the plan was economically attractive).
3. When excluding the benefits associated with the consumer surplus, the IRR decreases only marginally.
4. If the benefits are limited to the incremental energy, the IRR is negative (the costs exceed the benefits in every year of the period).
5. If the benefits are limited to those least uncertain (i.e., reduction of losses, incremental sales, and reduction of operating costs), the IRR significantly exceeds 12%.

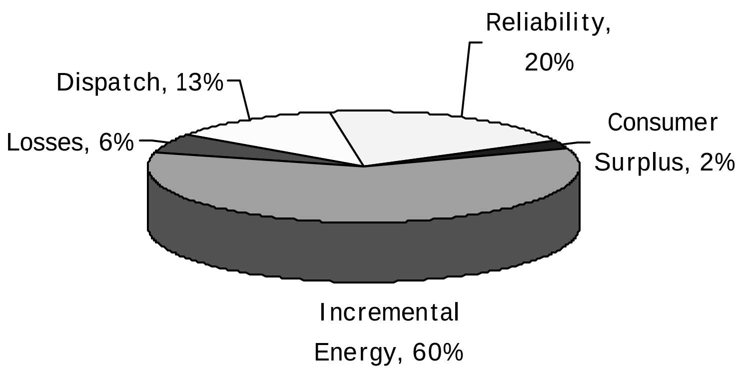

Figure 5. Incremental Energy was the Most Significant Benefit.

Finally, sensitivity analysis revealed the following:

1. as expected, uncertainties in load growth ratios only have an impact in the staging of the plans and not on the plans themselves, and
2. significant variations with respect to key variables (e.g., value of ENS, average tariff, and demand elasticity) still confirmed the economic feasibility of the plan.

VII. CONCLUSIONS

Power system planning methodologies need to adapt to changes that are occurring in the electric power industry worldwide. In particular, the traditional procedures need to explicitly consider the impact of parameters that traditionally were assumed to be either well-known or known with relative certainty. Additionally, methodologies should address technical, economical, and regulatory issues in an integrated framework.

This paper hopes to have presented a transmission planning approach, which satisfies these requirements. In particular, our approach considers structural uncertainties (e.g., those associated with both location and size of new generating power stations) to produce robust transmission plans. Additionally, the planning process involves a rigorous economic analysis of the transmission plans.

BIOGRAPHIES

Ramón Nadira is a graduate of Case Western Research University, Cleveland, Ohio (PhD, 1989). He is currently a Vice President in the Houston office of Stone & Webster Management Consultants, Inc. He provides advise to stakeholders in the electricity sector in the U.S. and worldwide.

Ricardo Austria received his BSEE from University of Santo Tomas, Manila, Philippines, and the MSEE from Rensselaer Polytechnic Institute, Troy, NY. He is currently the Director of Consulting Services at Shaw Power Technologies, Inc. in Schenectady, NY.

Carlos Dortolina received an Electrical Engineering degree from USB, Caracas, Venezuela, the MSEPE from Rensselaer Polytechnic Institute, Troy, NY, and the MBA in Economics from Universidad Católica Andrés Bello, Caracas, Venezuela. He is currently a Senior Consultant in the Houston office of Stone & Webster Management Consultants, Inc.

Miguel A. Avila received his BScEE and MScEE from Instituto Politécnico Nacional, México, in 1972 and 1977, respectively. He also received a MASc EE from the University of Toronto, Ontario, Canada, in 1979. He is currently the Area Manager of Transmission Planning of Comisión Federal de Electricidad in México.

The views expressed in this article are those of the authors', and do not necessarily reflect those of their respective organizations. Errors and omissions remain the authors' sole responsibility.

ENDNOTES

1 A mighty "force" (pun intended).

2 This is probably the only truly nondiscriminatory force at play in today's power systems.

3 Merrill, H.M., and A.J. Wood, "A Busy Signal for Electric Power: A Day in the Life of N.U. Gigawatt," *The Electricity Journal*, Vol. 3, No. 3, April 1990.

4 Electrons do not flow, like many people claim. Instead, power systems exert a "force at a distance."

5 The uncertainty associated with developing transmission projects in the U.S. is not unlike that of developing hydro power projects (i.e., long development times in which the project earns no revenues). To compound this problem, when developing transmission projects, there is no reasonable certainty that the project will ever be actually developed. Thus, the risk of investing significant sums of money without the possibility of ever earning a return is quite real.

6 We find it rather interesting that when asked, many would-be transmission developers have no clear idea about what ranges of return on investment would be required to develop transmission projects in the U.S.

7 In the U.S., the FERC is considering regulations that will facilitate new transmission construction.

8 This can be somewhat mitigated in those jurisdictions where the corresponding regulator has the ability to enforce eminent domain authority. This is not the case in the U.S. In fact, in the view of some observers, unless and until the Federal Energy Regulatory Commission is given such authority by Congress, expanding transmission in the U.S. will remain to be an activity mired with uncertainty.

9 Statement of Pat Wood, III, Chairman of the Federal Energy Regulatory Commission, August 15, 2003.

10 Nadira, R., R. Austria, C. Dortolina, and F. Lecaros, "Transmission Planning in the Presence of Uncertainties," Proceedings of the IEEE 2003 PES General Meeting, Toronto, Canada, July 2003.

11 See Schweppe, F.C., H.M. Merrill, and W.J. Burke, "Least Cost Planning: Issues and Methods," *Proceedings of the IEEE*, Vol. 77, No. 6, June 1989, Merrill H.M. and P.D. Fuller "Playing Leapfrog with a Unicorn: Risk and Uncertainty in Power System Planning", paper published at the Minnesota Power Systems Conference, St. Paul, MN, October 1992, or Pereira, M.V.F., M.F. McCoy, and H.M. Merrill, "Managing Risk in the New Power Business," *IEEE Computer Applications in Power*, April 2000, pp. 18-24.

12 The distinction between **risk** and **uncertainty** is important. Some factors which can have a major influence on a decision are not under the control of the decision-maker or cannot be predicted with certainty. These are uncertainties. Risk, on the other hand, is the hazard to which a decision is exposed because of uncertainty. Risk has to do with attributes like cost of electricity, capital requirements, and reliability, but there is considerably more to risk than how these might vary.

13 Risk is a characteristic of decisions, with two dimensions: (1) **robustness**, or the likelihood of a decision being regrettable (robustness is a measure of how insensitive a given decision is to the materializations of the uncertainties. A completely robust plan is one which would be selected for every future, that is, no matter how the uncertainties turn out), and (2) **exposure**, the conditions when, and the amount by which, the decision is regrettable. Unless a decision is 100%

robust, even the least-risky plan carries some risk of a regrettable outcome. The distinction between outcomes and decisions is important because, as one analyst has said, "unlike *quality of outcomes*, which depend on … (uncertainties), the *quality of decisions* is directly controlled by …" decision makers.

[14] In the U.S., for example, the North American Electric Reliability Council (NERC) is the organization in charge of setting reliability standards and ensuring compliance with these standards. However, currently such compliance is not mandatory.

[15] When there is no reserve capacity in the transmission system we say that there is "congestion". This is not always due to transmission lines reaching their current-carrying capacity (i.e., thermal limits). Sometimes congestion is due to voltage or stability limits. The point is that these limits are established by the standing reliability criteria.

[16] Allan, R.N., R. Billinton, S.M. Shahidehpour, and C. Singh, "Bibliography on the Application of Probability Methods in Power System Reliability Evaluation, 1982-1987," *IEEE Transactions on Power Systems*, November 1988.

[17] Nadira, R., K.A. Loparo and T.E. Dy Liacco, "Maximal Load Demand Allocation," *IEEE Trans. on Power Systems*, Vol. 7, No. 2, May, 1992, pp. 528-535.

[18] Risk is **not** an attribute. An attribute is a measure of the goodness of a particular *plan* and is meaningful only for a specified future, or set of outcomes of uncertainties. Risk is the chance that a *decision to select* one particular plan (instead of another) will be regrettable, and the magnitude of the regret in terms of the attributes, depending on how the uncertainties are realized. The key risk is the risk of making the wrong decision, and this must be viewed in the context of the other decisions that are available.

[19] Two useful approaches to modeling uncertainty are (TOR analysis is able to handle both of these approaches): (1) **Probabilistic**: probability distributions for all of the uncertainties are assumed; and (2) **Unknown but Bounded**: upper and lower limits on the uncertainties are assumed, with no assumption about probability distributions.

[20] Risk may be minimal, even if the most attractive plan is not completely robust. This could be because the futures for which the plan is not in the decision set are very unlikely. Or the exposure could be low because the difference in attributes is small between the plan selected and plans in the decision set for the adverse futures. If a decision is risky, however, ways should be sought to mitigate the risk (i.e., hedge). Good plans are made better by developing hedges against adverse materializations of uncertainties.

[21] Austria, R.R., R. Nadira, L. Cosenza, C. Fuentes, M. Avila, and J. Ramírez, "Least-Cost Transmission Planning Considering Power Industry Restructuring", IASTED Conference, Orlando, FL, October 1997.