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Capricious Cables: Understanding the Key Concepts in Transmission Expansion Planning and Its Models

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National Renewable Energy Laboratory

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1 Introduction

The extra-high-voltage transmission network is the bulk transport network of the electric power system. The design of this network determines which generation resources—whether hydropower, natural gas, wind, solar, coal, or geothermal—can be brought to market. Solving the major issues facing the power system—such as continuing drought, climate change, and natural gas network coordination—will depend on wide-area coordinated planning of the transmission network. However, the complex economic and physical relationships in the power system make it difficult to predict how the transmission planning decisions of today will impact the power system of the future. To understand how the future power system may react to planning decisions today, wide-area transmission models are increasingly used to aid decision makers and stakeholders. The goal of this work is to illuminate these models for a broader audience that may include policy makers or relative newcomers to the field of transmission planning.

Transmission expansion planning models attempt to simulate trade-offs in the planning process in their simplest form. Ideally, a transmission model would be able capture the entire planning process; however, even relatively simple models are difficult to solve because of the large number of complex computations that are required. As a result of this computational complexity, transmission system modelers simplify many aspects of a power system. These simplifications can drive the results of an individual model, as will be demonstrated using simple examples throughout this paper.

The computational complexity and the difficulty of interpreting model results are driven by two characteristics of transmission networks. First, a transmission system is a network driven by the laws of physics. Second, new investments in transmission or generation are capitally intensive—requiring significant financial capital—and “lumpy,” because they can only be built in discrete increments. As a result of these two characteristics, planning models may not be intuitive and can be very sensitive to input parameters—small variations in model inputs can potentially produce very different model outputs. Adding to the complexity of understanding model results, modelers rarely have access to data governing specific generator contracts, ad-hoc reliability constraints considered by system operators, or other proprietary data. Thus, some of the features of the existing transmission system are unknown and cannot be represented in a model at all. Given these complexities, the most important outcome of a modeling exercise is an understanding of the system’s behavior, the model’s limitations, and the implications of its limitations.

Understanding the implications of modeling assumptions, simplifications, and lack of information can be difficult. This paper explains the basic transmission expansion planning model formulation and highlights six of the major simplifications made in transmission expansion planning models. The six major examples highlight two temporal simplifications, future uncertainty in generation development, inclusion of externalities, and technical simplifications. The examples presented herein are very simple by design. The intent is to highlight the simplifications made by various models and the resulting need to contextualize model results using knowledge from other models and knowledge not captured in the modeling process.

2 The Basic Formulation

Transmission network expansion planning has been studied using computer algorithms since the late 1960s (Garver 1970). Although the algorithmic solving of the transmission expansion planning problem has evolved with dramatic increases in computation power, the core of the problem has not changed. A planning model is naturally framed as an optimization: minimize the cost required for a system to operate subject to physical and institutional constraints. Transmission expansion planning models minimize this cost by balancing the cost of new transmission investments against decreases in losses, generation costs, and the cost of energy not served. (Expected energy not served, EENS, is often the output of a probabilistic algorithm that produces a mathematical "expectation" that some load may not be served.)

Most models are presented in their mathematical forms, not in prose. The set of equations, or formulation, describing the model is explained in Box 1, which shows the most common and critical elements of most models.

The core of an optimization model is the objective function. This mathematical equation expresses the goal, or objective, of the model. In a basic expansion planning model, the objective function minimizes the investment of the cost of new lines and operational (generation and non-served energy) costs on an annualized basis. The quantities that the model can change to achieve the lowest cost are called decision variables. In a transmission expansion planning model, the key decision variables represent whether a specific transmission line will achieve part of the goal of the objective function. This means that in the modeling process some lines will be "built" and others will not.

Following the objective function are constraints. These constraints set the conditions that a solution must meet. For example, a generator may not produce more power than its rated size. There are two key constraints in the transmission expansion planning problem. The first, Constraint 1 in Box 1, is the energy balance at each bus. This constraint requires that the demand at each bus is equal to the sum of the energy generated at the bus plus flow into the bus and minus flow out of the bus. Throughout an entire electric power system, this constraint implies that all demand must be met, and the quantity of generation must be equal to the demand. The second key constraint, Constraint 2 in Box 1, is an approximation of the alternating-current load flow. It relates the physical properties of the line to the phase of the alternating current at each bus. The formulae and terms used in Box 1 are the technical jargon used by modelers when describing which aspects of transmission planning their models capture. Understanding this terminology is important both for understanding information presented by modelers and being able to frame questions to modelers.

Box 1. Transmission Expansion Planning Model Formulation

Objective function—The goal of the model

Minimize

$$\text{transmission\_cost}+\text{operational\_cost}$$

$$\textit{operational\_cost}=\text{cost\_generation}+\text{cost\_eens}$$

$$\textit{transmission\_cost}=\text{cost\_per\_line}*\text{x}$$

where x is the variable indicating whether or not a specific investment is selected.

Decision Variables—The quantities that the model chooses. For transmission planning, the primary decision variable of interest is whether or not a transmission line between two nodes is constructed.

Constraints—Restrictions on the values that variables may take or other conditions a solution must respect

Constraint 1) $demand(i)=generation(i)+eens(i)+flow\_in(i)\text{-}flow\_out(i)$

The demand at any bus, *i*, must be equal to the amount of generation at that bus, the non-served energy, and the flow on any transmission lines into the bus minus any flow out on any transmission lines.

Constraint 2) $flow(i,j)=\gamma_{ij}(\theta_i\text{-}\theta_j)$

The flow on any transmission line between two buses (*i* and *j*) is proportional to the physical properties of the line and the difference in voltage angles at each bus. This constraint represents Kirchoff's second law and is an approximation that is called the direct-current load flow.

Constraint 3) $flow_k \leq max\_flow_k$

The flow on any line, *k*, between two nodes cannot be greater than the maximum capacity rating for that line.

Constraint 4) $gen\_min \leq \text{generation} \leq gen\_max$

The output of any generator must be between its minimum and maximum output ratings.

Constraint 5) $x \in 0,1$

Each possible investment, *x*, must be assigned a binary value of zero or one. The value is one if the line is constructed and zero if the line is not selected for construction.

3 Temporal Simplifications

Transmission lines are capitally intensive investments with economic life spans of 40 or more years. During the life span of these investments, the power system will continue to evolve. Existing generators will retire, and new generators will be added. Loads will increase and decrease with economic changes and new development patterns. Fuel prices will fluctuate, as will national policies and environmental regulations. None of these potential future values or events is known with certainty—and even if they were a transmission expansion model could not capture all of these varying future events and do so over all relevant time steps and -scales. Instead, modelers simplify the number of time horizons to capture the most important details.

One of the most common simplifications made in transmission expansion planning models is to consider only a single investment decision time period. With this simplification, modelers plan for a specific target year. Traditionally, plans have been constructed for short-term horizons (5 to 10 years) or long-term horizons (20 to 30 years).[1] The short-term horizon simplification is problematic because economies of scale are not captured in the modeling. As an example of these economies of scale on a thermal-capacity basis, a 345-kV double-circuit line (a tower with two sets of conductors) costs $1,333/MW-mile, whereas a 765-kV single-circuit line (a tower with one set of conductors) costs 70% less, $413/MW-mile[2]; however, with a limited time for demand to grow, the need for larger lines is never recognized. On the other hand, with a long-term horizon and the assumption of no new transmission for 20 to 30 years, there is pent-up demand for new transmission and large lines are almost exclusively selected.

This concept is illustrated in a simple three-bus model in Figure 1. In this model, a single load exists at Bus A with generators at Bus B and Bus C. These generators are already connected to Bus A via two 300-MW lines; however; these existing lines cannot meet the new demands in years 10 and 20. In this system, there are two investment options to expand capacity: (1) a 750-MW line from Bus A to Bus B for an annualized cost of $5 million, or (2) a 1,500-MW line in the same corridor for $7.25 million annually. In a traditional myopic formulation, only the load in year 10 would be considered. In this case, only 400 MW of transmission capacity are required to meet the load, and the lowest-cost investment is the smaller 750-MW line. However, if a second time horizon, such as 25 years, is considered, the demand has grown to 1,500 MW, and now an additional 900 MW of capacity is required to meet the demand at Bus A. The lowest-cost option is now the more expensive but larger line.

[1] The Midcontinent Independent System Operator and Southwest Power Pool have attempted to close these gaps. See, for example, the Southwest Power Pools Integrated Transmission Planning Reports: http://www.spp.org/publications/20130730_2013_ITP20_Report_clean.pdf.

[2] Thermal limits and costs from American Electric Power

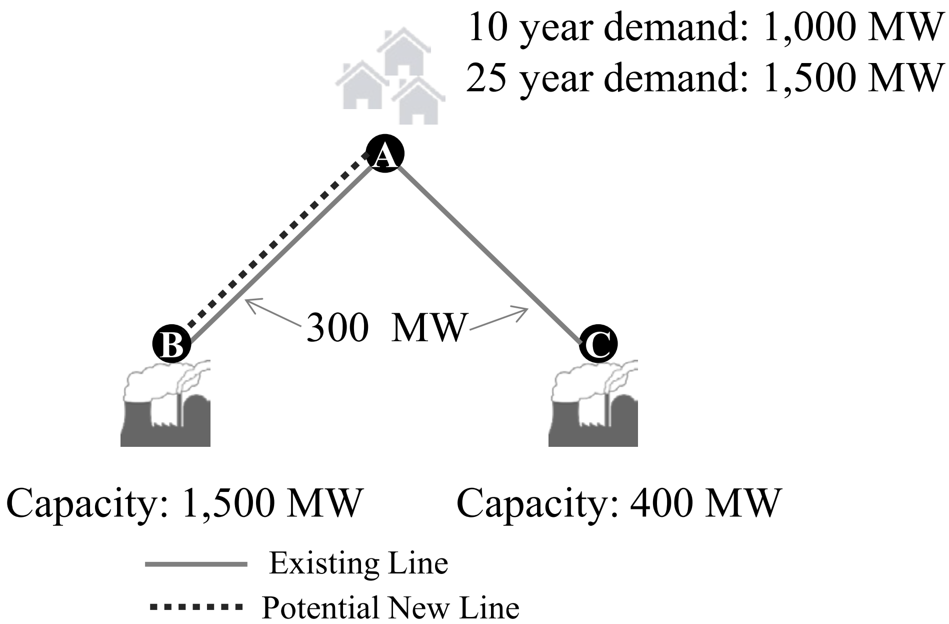


Figure 1. Test system for the time horizon simplification

If the myopic model was used and only the smaller line was constructed, a second 750-MW line would need to be added to the system to meet the demand in year 25. This would have a net cost of $10 million, $2.75 million more than the single $7.25-million line, which would be sufficient to meet demand in both year 10 and year 25. It is important to note that these cost figures, though somewhat arbitrary, are scaled to reflect relative costs of transmission lines and generation. Given these costs, differentials between transmission options are commonly measured on the scale of millions of dollars.

Table 1. Investment Costs and Capacities for the Time Horizon Simplification

	Cost $M	Capacity (MW)
Line A-B Medium	5.0	750
Line A-B Large	7.25	1,500

A possible conclusion from the example above is that larger lines should always be selected. A segment of transmission planning community makes this argument, called "right sizing" (Rivers 2010). This is not the argument we make here. The efficacy of right-sizing a line depends on the evolution of the power system over the lifetime of the investment, the size of the lines considered, and the difficulty of adding new lines in a specific geographic region. For example, right-sizing may not be the most economic solution for an area that has low demand and stagnant load growth. Instead, the point of the example above is that models commonly assume a single time horizon and different answers can be easily obtained even in small problems when multiple time horizons are considered. In large systems with thousands of buses, considering multiple time horizons can alter the location of a new transmission investment and its size.

A second common temporal simplification in models is to consider few operational hours. Production cost modeling programs such as PROMOD, GE MAPS, GridView, and PLEXOS traditionally include the full 8,760 hours in each year. However, including the full 8,760 hours in a year is too computationally demanding for planning models. As a result, a few select hours are modeled. In some cases, only a single peak hour is modeled. The logic behind this is intuitive: if a primary goal of transmission expansion planning is to meet demand at the lowest possible price, why not choose the most demanding hour? Simply put, overemphasizing demand and thus generation costs throughout the course of a year biases the system toward over-development.

For example, consider Figure 2, which depicts the three-bus system now modified to show two different demand levels. The system has a peak load of 1,250 MW and an off-peak load of 500 MW. If only the peak hour is considered, the lowest-cost option is to build the larger 1,500-MW line. This configuration and its cost calculations are given in Box 2; the cost of the system with different configurations is given in Table 2. This large line allows the full peak load of 1,250 MW to be met using the lower cost plant at Bus B. However, if peak conditions are assumed to exist for 10% of the load hours and the remaining 90% are non-peak, now the lowest-cost option becomes building the smaller 750-MW line. The smaller line becomes a lower cost option because the demand can be met 90% of the year with the lower cost generator at Bus B. The more expensive plant at Bus C is required only during the remaining 10% of peak hours.

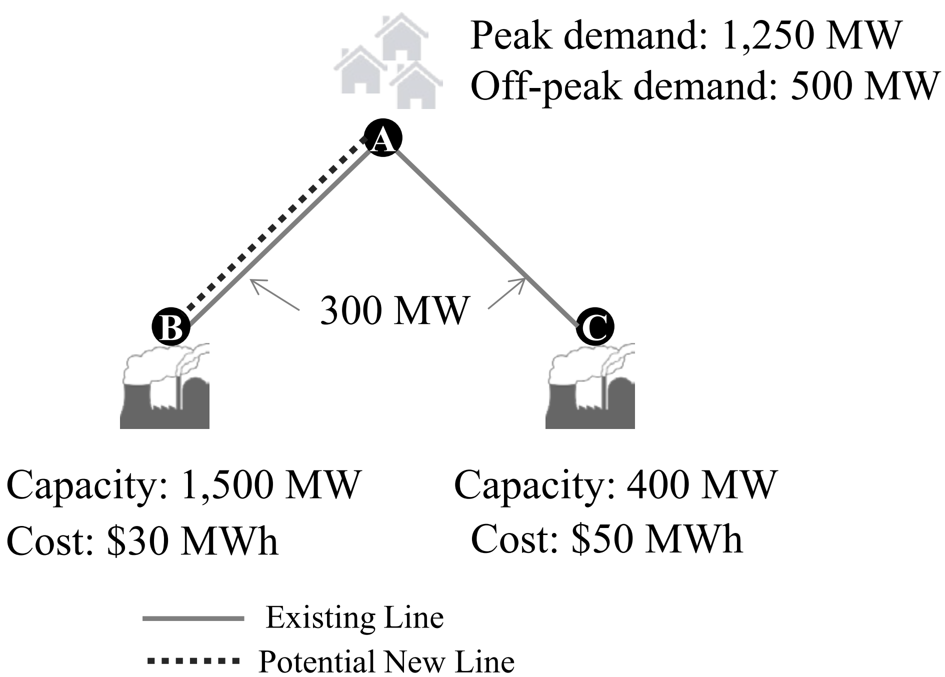


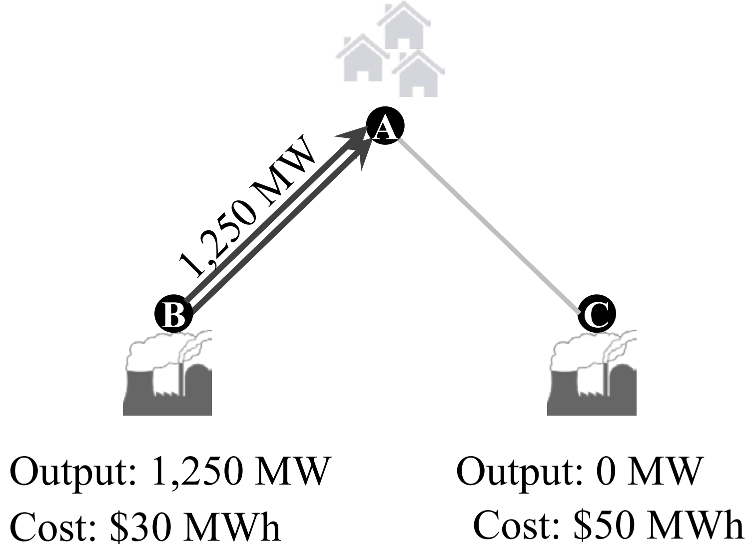
Figure 2. Test system for hourly demand simplification

Table 2. Investment Costs and Capacities for Hourly Demand Simplifications

	Line Cost ($M)	Capacity (MW)	Peak Hour Only System Cost ($M)	Peak and Off-Peak System Cost ($M)
Line A-B Medium	5.0	750	347	157
Line A-B Large	7.25	1,500	336	158

The simple problem shown in Figure 2 also provides insight into one of the fundamental issues in transmission expansion planning. The annual generation costs listed in Table 2 are two orders of magnitude larger than the annualized transmission costs. This is not an artifact of the example selected. In existing power systems, transmission costs are typically less than 10% of the total system cost. As a result of this difference in costs, transmission expansion planning models often select more transmission lines to access lower cost generation than are constructed in reality These modeled plans represent the most economic transmission expansion plans but do not account for institutional barriers such as siting or cost allocation. These institutional barriers can be partially incorporated into transmission expansion planning if an interactive process is used. For example, if a line selected by a planning model encounters an area with known siting issues, the line can be rerouted and the model rerun with the new capital cost, or it can be removed from the set of options that the model can select.

Box 2. Cost Calculation Example for Temporal Simplification 2, Peak Hour Only



Total Cost Annual

Cost	=	Transmission cost	+	Operational cost
Cost	=	$5{,}000{,}000 \cdot x_{medium} + 7{,}250{,}000 \cdot x_{large}$	+	generation_cost·hours
Cost	=	$5{,}000{,}000 \cdot x_{medium} + 7{,}250{,}000 \cdot x_{large}$	+	$8760(30 \cdot gen_A + 50 \cdot gen_B)$
Cost	=	$0 + 7{,}250{,}000$	+	$8{,}760(30 \cdot 1250 + 50 \cdot 0)$

Demand

Demand(i)=		generation(i)	+	non-served energy(i)	+	flow in(i)	-	flow out(i)
A:	1,250 =	0	+	0	+	1,250	-	0
B:	0 =	1,250	+	0	+	0	-	1,250
C:	0 =	0	+	0	+	0	-	0

4 Uncertainty Simplifications

Almost all transmission planning models consider specific scenarios with perfect knowledge. That is, the modeler assumes that all future demands, fuel prices, generator locations, and reliability issues are known. In reality, of course, there is very imperfect knowledge about the future. Natural disasters destroy infrastructure and cause major changes in fuel prices. Technological breakthroughs produce new generation types not known to today's planners. To capture some of this uncertainty, planning models can try to produce transmission plans with low costs projected to a variety of different futures.

Consider the three-bus example shown in Figure 3. In this iteration of the model, a new low-cost power plant may be constructed at Bus C, and three different investment options are presented by the planner (given in Table 3). The total system costs assuming each transmission and generation scenario are given in Table 4. If the planner had perfect foresight and knew that the plant would not be built, the lowest-cost investment option would be to build Line A-B and Line B-C. Note that because the system is networked, the most intuitive solution—building Line A-B only—is not the lowest-cost option in any scenario. Instead, building the additional line between Bus B and Bus C allows the lower cost power plant at Bus B to meet the entire load at a lower cost by sending power across the new lines and the existing line between Bus A and Bus C. On the other hand, if the planner had perfect foresight and knew that the new generator would be built, the lowest-cost option would be to build only the additional capacity between Bus A and Bus C. If the planner assumes that the generation is built and adds only Line A-B, but the generation developer pulls out, the system becomes very expensive—by nearly a factor of five more—to operate.

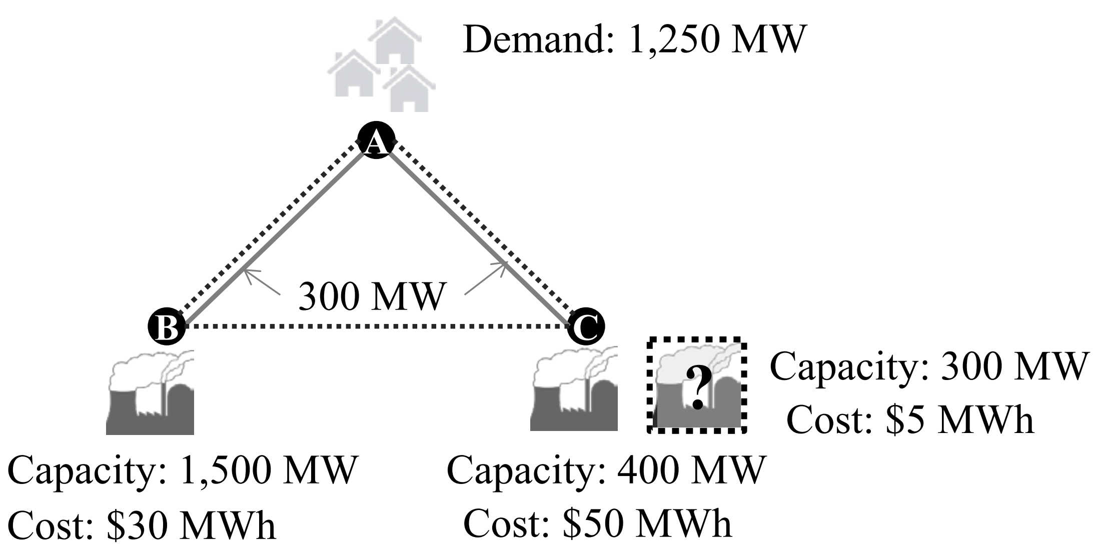


Figure 3. Test system for generation location uncertainty

Table 3. Transmission Costs for Generation Uncertainty System

	Cost ($M)	Capacity (MW)
Line A-B	5.0	750
Line A-C	5.0	750
Line B-C	3.0	500

Based on the disparity among potential costs in the example above, it is clear that the objective is to find a plan that does well across a variety of possible futures, rather than one that performs well for a single scenario. In the example above, if there is a 50% probability that the generation will be developed, the transmission build-out with the highest expected value includes Line A-C and Line B-C. *Expected value* is the modeling term for weighted average, and it implicitly assumes that the decision maker is neutral. In the example here, if the probability of new generation increased to 60%, the expected cost for the Line A-C, B-C build-out would decrease from $248 million to $231 million, as shown in Table 5.

Table 4. Generation Uncertainty System Costs Given Different Generation and Transmission Scenarios

System Costs	New Generator ($M)	No New Generator ($M)	Expected Value ($M)
Line A-B	268	369	318
Line A-C	104	500	302
Lines A-B, B-C	161	336	248

Table 5. Calculation of Expected Cost for Generation Uncertainty System

New Generator				No New Generator				
Scenario Cost ($M)	*	Probability of Scenario	+	Scenario Cost ($M)	*	Probability of Scenario	=	Expected Cost ($M)
161	*	0.5	+	336	*	0.5	=	248
161	*	0.6	+	336	*	0.4	=	231

With a risk-neutral decision metric, it does not matter how a transmission plan performs in individual scenarios as long as it performs well on average. A selected plan that has a risk-neutral decision metric could perform very well under one scenario yet very poorly scenario under all other scenarios. Likewise, the plan could perform very well on average but very poorly in a single scenario. Other decision metrics exist to differentiate between risk-averse and risk-seeking plans, but expected value is the most common modeling metric.

The simplifications thus far have been presented individually. In reality, however, the effects are not easily separable. The test system presented in Figure 4 considers two time periods and uncertainty regarding the construction of a new generator. The test system shown includes two existing generators, at costs of $30 MWh and $45 MWh, as well as two existing 400-MW capacity transmission lines. Three possible lines may be constructed: (1) a large line from Bus A to Bus B, (2) a medium line from Bus A to Bus B, or (3) a medium line from Bus A to Bus C. This example combines the effects of uncertainty and multi-period modeling.

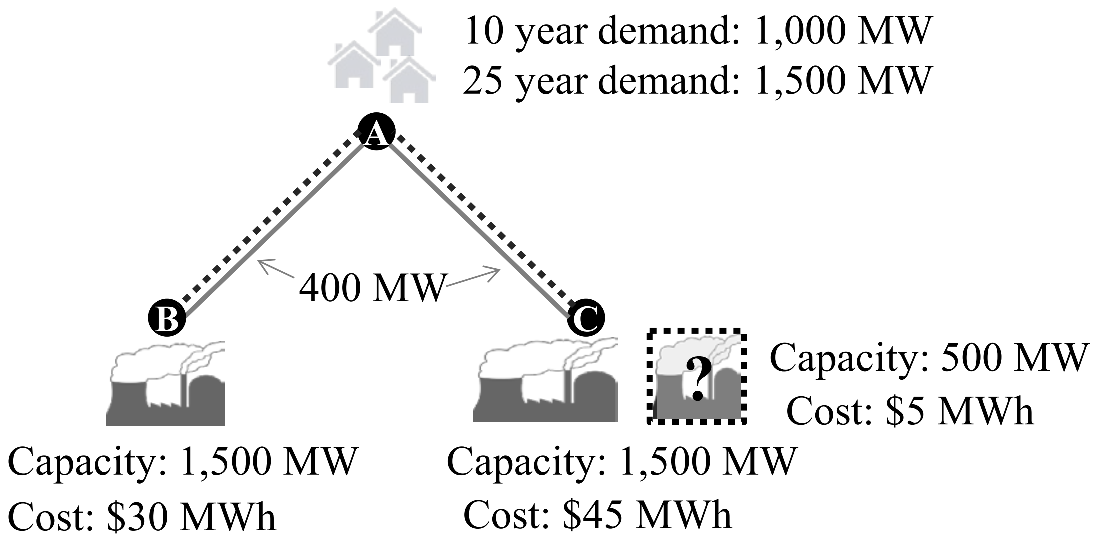


Figure 4. Test system combining uncertainty and multi-period modeling

A myopic view of the test system that considers only the first period would always select only the medium-size Line A-B. The medium-size line allows the demand at Bus A to be met at the lowest possible cost in the near term. However, this solution is blind to both the development of new generation and the growth in demand. If both time periods are considered and the planner knows that the new generation will not be built, the lowest-cost investment option is the large-size Line A-B. The large line allows the full demand at Bus A to be met with the cheaper generation available at Bus B across both horizons. However, if the planner considers both time periods and knows that the generation plant will be built, the lowest-cost transmission decision is to build the medium-size Line A-B during the first period and add Line B-C during the second period.

Table 6. Transmission Characteristics for the Uncertainty and Multi-Period Modeling Test System

	Cost ($M)	Capacity (MW)
Line A-B Medium	5.0	750
Line A-C Large	7.5	1,500
Line B-C	5.0	750

Table 7. Minimum Cost of First-Period Transmission Investments

First-Period Transmission Investment	New Generation ($M)	No New Generation ($M)
Line A-B Medium	363	411
Line B-C Large	366	400

In this example, the lowest-cost decision depends on whether or not the new generation will be built. Each point shown in Figure 5 represents the expected total cost for the test system shown in Figure 4 for different transmission investments when the probability of new generation varies from 0% to 100%. For example, when the probability of new generation is 10%, the expected system cost with the medium line is $396 million, and the expected cost with the large line is $406 million. When the probability of new generation is 90%, the large line—which has an expected cost of $367 million—becomes a less-expensive option than the medium line, which has an expected cost of $369 million. As shown in Figure 5, building the medium line from Bus A to Bus B is the lowest-cost decision as long as the probability of developing new generation is less than 80%. Although not shown in this small example, using an expected value across scenarios may identify line combinations with average values in individual scenarios but with high expected values when considering multiple scenarios. Lines with average values may not be identified if only high value lines from scenario analyses are considered. From a planning perspective, there is some certainty about whether an existing generator will retire or a new generator will come online if construction has begun. This timescale, however, is mismatched to the transmission planning timescale—a new transmission line takes 5 to 10 years to plan and build, whereas a new wind plant may be permitted and constructed in less than 3 years. Thinking further into the future and considering the 40-year life span of a transmission investment, it is impossible for a planner to know how the future will evolve. As a result, the planning discussion returns to one of risk. In the example here, the risk of no new generation and constructing the wrong size line must be weighed against the potential economic benefits of developing new generation.

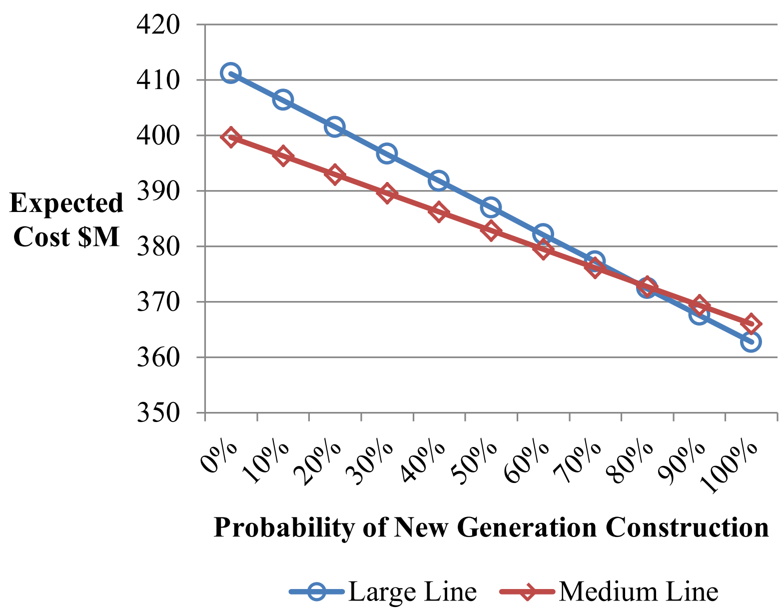


Figure 5. Risk illustration for new generation uncertainty

5 Externalities

Thus far, the costs included in the transmission expansion planning process have not included the external costs imposed by the power system. External costs, such as land use impact and air pollution, are those that are not directly priced and may be imposed on unwilling or unknowing participants. These costs can greatly influence the lowest-cost transmission plan by accessing different generation resources and rerouting lines.

The goal of an optimization-based transmission planning model is to plan the lowest-cost system. Given the large number of transmission lines under consideration, often transmission line costs are modeled using straight lines between buses. Modelers do not have sufficient geographic or political knowledge to route lines, and it can be untenable to try to route them individually when thousands of lines are being considered. As a result, plans from transmission expansion models underestimate transmission costs and may produce transmission routes going over mountain peaks or through protected habitat. Correcting these may change the optimal decision set.

In the test system shown in Figure 6, it has been discovered that a straight-line route must be modified to avoid using sensitive land. This test system contains two existing generators; two existing 400-MW capacity lines; and two new investment options, one between Bus A and Bus C and one between Bus B and Bus C. Without rerouting, the lowest-cost solution was to build Line A-B and Line B-C. The solution assumed that a straight line could be drawn between all buses. However, in the example below, it has been discovered that the proposed line between Bus B and Bus C passes through a protected forest. To avoid using the sensitive area, the line must be rerouted. The additional cable, right-of-way, and installation required with the new route increases the cost such that the lowest-cost solution becomes building only Line A-B, as shown in Table 8 and Table 9.

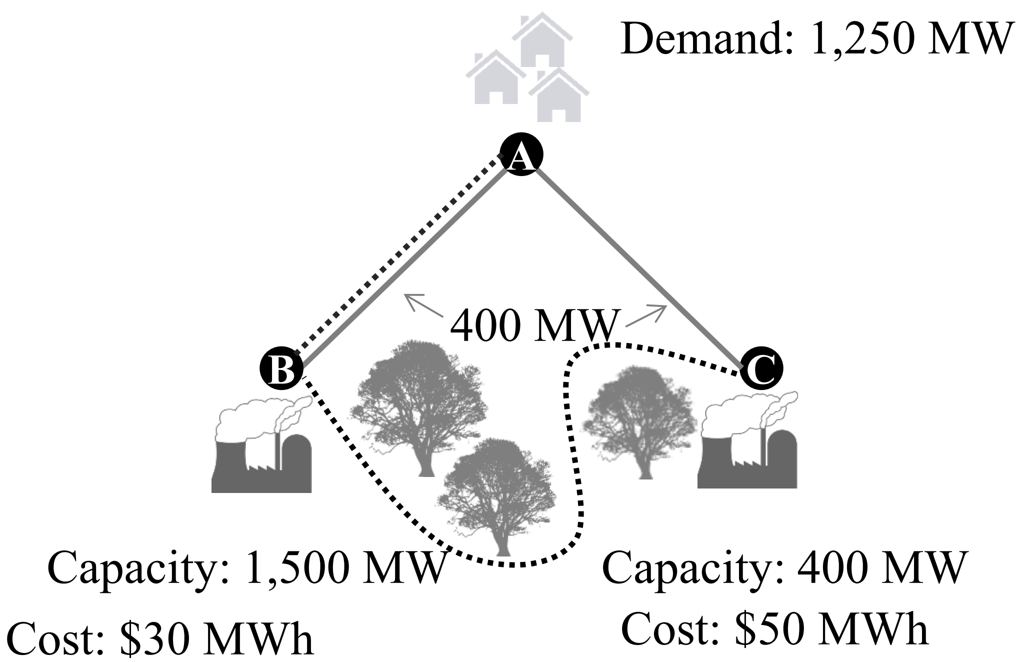


Figure 6. Rerouting externality test system

Table 8. Transmission and Generation Costs with Rerouted Line B-C

	Rerouting Line B-C ($M)
Line A-B	377
Line A-C	337
Line A-B, B-C	378

Table 9. Transmission Cost Characteristics Before and After Rerouting Line B-C

	Cost ($M)	Capacity (MW)
Line A-B	5.0	600
Line A-C	5.0	600
Line B-C (Straight Line)	3.0	300
Line B-C (Rerouted)	9.0	50

Another set of externalities that may affect the results of a transmission expansion planning model is that of generator pollutant emissions. These include local air pollutants such as NO_X and SO_X as well as greenhouse gas emissions such as CO_2. Although it should be reiterated that these pollutants are unlikely to be included in a model unless explicitly stated, there are two common ways to include them. The first method is to develop a cost for each type of pollutant. These costs may be set to mirror market costs for the specific pollutant or may be set to the "social cost" of the emissions. Social costs are intended to quantify all external impacts of the pollution on current and future generations. For example, CO_2 could be priced at $50/ton; this type of pricing is often referred to as a carbon tax. In the second method, a cap is set for each pollutant type. For example, a system could be limited to emitting 1 million tons of CO_2 per annum. Both the cap and pricing methods can be calibrated to produce the same generator dispatches and transmission plan results; however, it is difficult to compare the stringency of imposed cap and cost policies across models. Our goal here is not to debate which method—cap or price—is preferred, but to demonstrate the effect of emission externalities on transmission expansion planning.

In the example below, there are two existing generators and two 300-MW capacity transmission lines. The two generators have been assigned generation costs and emissions rates. In the base case, in which no pollutant-externalities are considered, the most economic option is to build Line A-B; this line accesses cheaper generation from the plant at Bus B. However, if a $45 emissions price is added, the effective price of the plant at Bus B raises from $30/MWh to $97.50/MWh. In this case, the plant at Bus C is now more economic because it has an effective price of $72.50/MWh. The most economic solution to meet demand with a $45/ton emissions price is to build Line A-C. As shown in this small example, the inclusion or exclusion of emissions prices has the ability to change the optimal transmission plan.

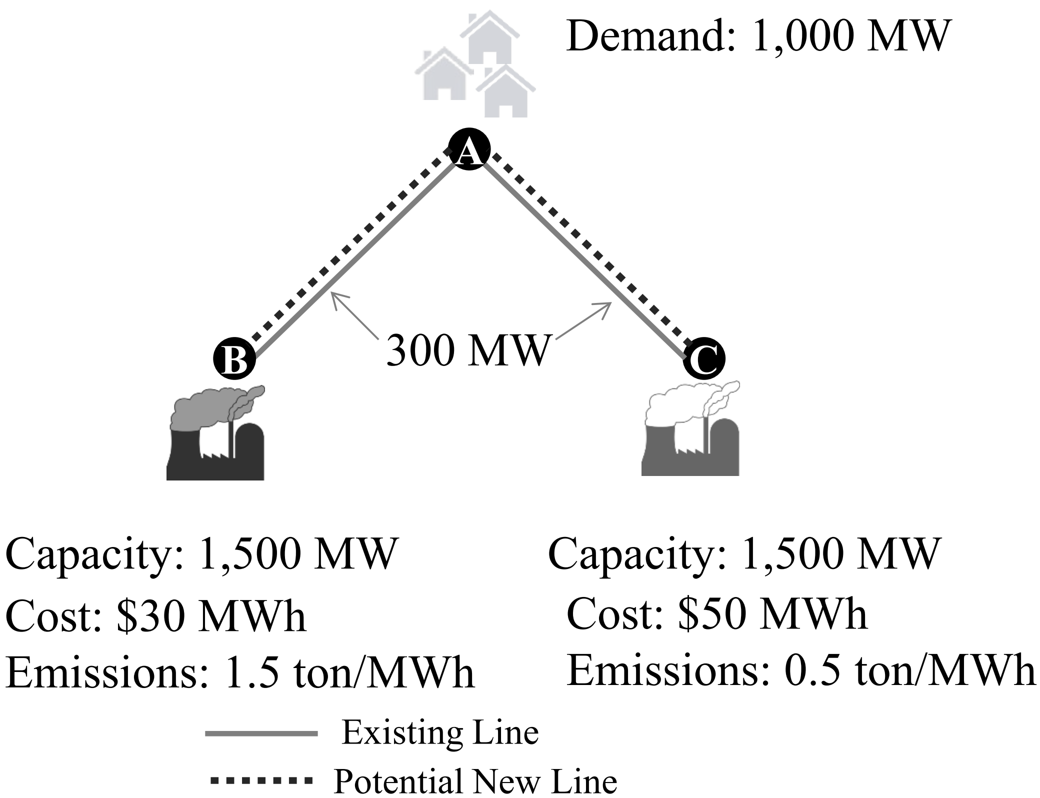


Figure 7. Air pollution externality test system

Table 10. Transmission Characteristics for Air Pollution Externality Test System

Transmission Characteristics	Cost ($M)	Capacity (MW)
Line A-B	5.0	750
Line B-C	5.0	750

A closer look at the example shows that there is a pollutant price at which both generators will have the same effective price. At $40/ton, both generators have an effective price of $70/MWh. If the pollutant price were set to $39.99/ton, the model would select Line A-B; however, if the pollutant price were set to $40.01, the model would select Line A-C. This type of "knife-edge" behavior, in which a minor change in input produces a dramatic change in output, is not unique to pollutant prices. Small changes in fuel prices, line costs, and other inputs can produce widely varying transmission plans. These abrupt changes are a result of the optimization algorithms underlying planning models. If the optimization algorithm finds a solution with a lower cost solution because of a small change in input, no matter how small, it will adopt the new solution.

This type of sensitivity is not revealed by a single model run, and without a sensitivity analysis there can be a false sense of confidence in the answer provided by the model. A sensitivity analysis is the process of changing the model inputs, rerunning the model, and comparing the change in outputs. If a model shows little sensitivity to varying input parameters, the solution found may be considered more robust. In our example problem above, if the generator at Bus B cost $75/MWh, building line A-C would be the lowest-cost solution regardless of the emission price or cap. A sensitive model is not a poorly formulated model and can provide stakeholders and decision makers with additional insight into the planning problem. On the other hand, depending on the results of the sensitivity analysis, a sensitive model may indicate that there are many good solutions, each with costs very near one another. A sensitivity analysis may also reveal the drivers of model behavior. One or two inputs, such as the cost of natural gas or the financial discount rate, may drive the results of planning models. Changing more than a single variable—for example, natural gas price and the financial discount rate—at a time reduces the number of model runs to be completed, but this type of sensitivity analysis does not provide insight into which variable is driving the change in results. Understanding these key drivers can help direct future studies and elucidate the major issues for stakeholders and decision makers.

6 Further Technical Simplifications

The test systems presented here vastly simplify the physics of the real transmission expansion planning problem. In each of the test systems, we assumed that flow was directable rather than using the direct-current approximation of the alternating-current load flow presented in Box 1. We also ignored reactive power, transformer costs, and reliability issues, such as N-1 contingencies and stability issues. The type of modeling presented here provides very valuable insight into the value of future transmission investments; however, it is fundamentally ill-suited to identify near-term reliability and power quality issues.

7 Conclusions

Wide-area transmission investments need to be planned today to prepare for an uncertain future. Future natural gas prices will almost certainly fluctuate as a result of demand and supply variations, potential future liquefied natural gas terminals, and/or governmental regulation on shale gas. National carbon-emission policies may result in high penetrations of renewable energy. Potential transmission line routings may change with the discovery of cultural heritage sites. Given these uncertainties and the complexity of transmission expansion planning, models are needed to help inform and guide decision-making processes. Temporal, technical, uncertainty, and externality simplifications and assumptions are made in planning models to reduce an otherwise computationally intractable problem; however, as we have shown in the examples presented, the simplifications made in transmission expansion planning models can greatly affect the results.

Because of modeling simplifications and because of the uncertainty in future power system development, no single model can capture or explore all aspects of the transmission expansion planning problem. The benefits of using transmission planning models do not result from considering a single solution, but rather by comparing sensitivities and trends across a variety of planning models and combining these results with broader contextual information.

References

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