Real Options and Transmission Investment: the New Zealand Grid Investment Test*

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Abstract

Responsibility for approving proposed transmission investment programmes in New Zealand has recently been placed in the hands of a newly-formed government regulator. In this paper, we develop an analytical framework for conceptualising the investment test proposed by this regulator. Our framework reveals that the test involves a complex set of tradeoffs between economies of scale, the time value of money, and flexibility in the timing, level and location of transmission investment, assessment of which requires explicit recognition and valuation of real options.

1 Introduction

Security of supply in electricity is a prerequisite for optimal economic growth and welfare, and one of the most important determinants of this security is the reliability and efficiency of the transmission grid system that transports electricity to locations where it is demanded. However, investment in transmission is subject to high costs and significant uncertainties. The first of these makes it important to get investment decisions right, while the second makes it difficult to do so.

New Zealand has recently adopted a new approach for assessing the desirability of potential investments in transmission capacity. In September 2003, responsibility for approving grid investment passed from the SOE responsible for the national grid (Transpower) to a newly-formed government regulator (the Electricity Commission).[1] Among other things, the Commission was required to develop a grid investment test (GIT) to assist in proposing, reviewing and approving grid upgrade plans.

The GIT that ultimately appeared in February 2005 sets out an *expected net market benefit* test for transmission investment.[2] This test consists of three steps. First, market development scenarios associated with the proposed investment are identified. Second, the investment's net market benefits (benefits minus costs) *within* each scenario are estimated.[3] Third, the expected net market benefit is calculated as a probability-weighted average of the scenario-specific net market benefits. A proposed investment satisfies the GIT if the Commission is reasonably satisfied that the investment's expected net market benefit is positive and greater than that offered by any feasible alternative investment.

[1] For more information about the Electricity Commission, see www.electricitycommission.govt.nz.

[2] See New Zealand Electricity Commission (2005).

[3] *Market benefit* is the present value of the investment's benefits to users and suppliers of electricity over a 20-year period; cost is the present value of the investment's costs to users and suppliers of electricity over the same 20-year period.

At this level of generality, the GIT provides a broad outline for assessing potential grid upgrades rather than a specific template. One objective of this paper is to develop an analytical framework for identifying key sources of value associated with transmission investment decisions and, in particular, to highlight the importance of real options in this process. The GIT allows for real options analysis to be used in evaluating transmission investment, but does not require that this be done or indicate any method for doing so. Using a simple model, we show that an accurate assessment of transmission investment involves a complex set of tradeoffs between flexibility, economies of scale, and time value of money; although standard net present value (NPV) analysis can deal with some of these, real options analysis is required to complete the evaluation. As Joskow (2005) points out, most of the literature on transmission investment pays no explicit attention to the stochastic features that make real options valuable.

In the next section, we compare the GIT with the corresponding regimes in Australia and the United States and briefly summarize the essential features of real options. Section 3 develops a simple model for conceptualizing the choice of grid upgrade in a real options framework. In Section 4, we extend this model to consider the possibility of alternatives to transmission investment, the timing flexibility that this potentially gives rise to, and the complications and constraints created by lengthy construction times. Section 5 discusses issues that arise in attempting to quantify the model's insights. Finally, Section 6 offers some concluding remarks.

2 Background

2.1 The New Zealand Grid Investment Test

Although direct state control of the New Zealand electricity grid ceased in 1987, with the formation of Transpower occurring in 1994, it was not until 1996 that the wholesale market was able to produce nodal electricity prices measuring transmission loss and constraint rentals. Subsequently however, rather than linking transmission investment directly to pricing signals, Transpower's objectives were rebalanced to place greater emphasis on operational efficiency than on profitability. In particular, its pricing policy was more transparently made subject to government policy, and the wider industry was given greater say in determining grid quality requirements. Market-based instruments to signal the need for and to support new transmission investments — financial transmission rights — were mooted, but not developed.[4]

Transpower also faced obstacles in securing funding for new investments. While non-core grid investments could be contracted for with specific customers, Transpower encountered difficulties in enforcing its pricing terms with all customers. This meant that it was not able to secure a return on its grid investments, particularly those on the core grid, further complicating its investment decision-making. Following the failure of industry participants to agree on integrated, voluntary self-regulation, these problems saw the formation in 2003 of a compulsory, centralised

[4]See Evans and Meade (2001).

regulator — the Electricity Commission. While the Commission, not Transpower's board, is now ultimately responsible for approving Transpower's pricing methodology and investment proposals, Transpower retains discretion over the formation of investment proposals. And now it enjoys surety of funding for investments approved under the GIT, with industry participants required to comply with Transpower's approved pricing policy.

The GIT resembles the "market benefits limb" of the Australian National Electricity Code, an economic cost-benefit test used to evaluate electricity network investments by participants in the Australian National Electricity Market (NEM).[5] However, it differs from the GIT in several ways. First, it does not require proposals to maximise the expected net market benefit from investment, but rather that they maximise the net market benefits under the *greatest number of market scenarios*. Second, it allows investment proponents to determine an appropriate rate for discounting expected cash flows, whereas the GIT specifies a fixed, pre-tax real rate of 7% per annum. Third, the GIT is more flexible in that it explicitly allows for assessment based on real options analysis, whereas the Australian test is couched solely in NPV terms. Nevertheless, the Australian and New Zealand definitions of market benefits and costs are broadly similar.[6]

Both the New Zealand and Australian tests are markedly different from that applied in the United States. For example, in the case of PJM Interconnection, the Office of the Interconnection (OI) continuously monitors congestion on the grid and calculates hourly gross congestion costs associated with transmission constraints for each constraint's duration.[7] When cumulative monthly congestion costs exceed a predetermined threshold, the OI begins a cost-benefit analysis of remedial transmission expansions and enhancements. The cost-effectiveness of any upgrade is assessed by comparing the NPV of the total estimated net system benefit with the NPV of the total estimated cost of the facility over a ten year window. The net system benefit is defined as the value of the congestion that the upgrade would relieve, less the sum of (a) the costs of increased energy prices arising outside of the constrained region due to the constraint's removal, (b) the estimated value of any change in congestion on other facilities arising from the constraint's removal, and (c) congestion costs arising due to outages caused by the upgrade's construction. While both the New Zealand and Australian tests include consideration of the economic costs of grid congestion, neither is as directly focused on balancing these costs with the costs of grid investment as is the PJM test.

[5]The NEM commenced operation in December 1998, comprising the state electricity networks of Queensland, New South Wales, Australian Capital Territory, Victoria and South Australia, and from 2005, Tasmania. See NEMMCO (2005).

[6]For more details, see Australian Competition and Consumer Commission (2004).

[7]PJM coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. For more details, see Joskow (2005).

2.2 Real options analysis

Real options analysis attempts to value the flexibility that is inherent in many investment projects. Flexibility allows investment plans to be changed or deferred as new information arrives; by responding appropriately to the arrival of such new information, investment decision-makers are thus able to take advantage of new opportunities and/or to mitigate actual or opportunity losses. For example, most investment programmes can be abandoned prior to completion if, for instance, demand turns out to be lower than anticipated. In this case, flexibility potentially saves large amounts of unnecessary expenditure. Similarly, some investments can be expanded if demand turns out to be higher than expected, thereby reducing concerns about potential unmet demand. The role of real options analysis is to determine what such flexibility is worth.[8]

This can be contrasted with standard NPV analysis, which ignores the ability of decision-makers to respond to new information. To see the difference, consider the case of a commuter who must choose between driving a personal car to work or taking the train. The train provides the commuter with little or no flexibility — once aboard he must ride it to the end. By taking the car, however, he obtains the flexibility to take an alternative route if traffic conditions warrant. Standard NPV analysis weighs up the merits of car versus train travel by assuming that both always follow their expected routes, regardless of road traffic conditions; real options analysis assumes that the commuter can observe traffic conditions and adjust the route accordingly. More generally, real options analysis complements NPV analysis by including additional sources of value that are ignored by standard NPV calculations.

Because flexibility is valuable, real options are potentially important for many types of investment decision. Even when flexibility exists, however, the real options thus created are only important for investment decisions if four phenomena are present. First, the investment being considered needs to be at least partly irreversible. If not, and the cost of investment is thus fully recoverable, then there is no value in waiting to obtain new information and standard NPV is sufficient to evaluate projects. Second, the relevant features of the future need to be significantly uncertain. Flexibility is valuable because it allows decision-makers to react appropriately to new information, but there is little new information to be acquired, and hence little to react to, if the future can be accurately predicted. Third, the uncertainty needs to be financially material. If the NPV of an investment is insensitive (in either size or sign) to different scenarios, then new information will not lead to any action by decision-makers. Even in the presence of irreversibility and uncertainty, flexibility is valuable only to the extent that its utilisation has significant financial consequences. Fourth, the ability to utilise flexibility cannot be too constrained. For example, if the consequences of unmet demand are severe then the

[8] The importance of real options for investment decisions has been extensively discussed in recent years. For a relatively simple introduction, see Copeland and Antikarov (2001). A more advanced treatment is Dixit and Pindyck (1994).

ability to defer investment is significantly lessened, especially if investment takes a long time to put in place.

Because transmission investment programmes are characterised by high sunk costs and uncertain benefits, flexibility is likely to be valuable. This suggests an important role for real options in analyzing transmission investment choices, a feature we now seek to make explicit.

3 A simple model of transmission investment

In this section, we model a simple transmission investment choice: whether to undertake a large or small grid upgrade. There are two periods and the best investment is the one that provides the highest present value of net benefits across the two periods. For simplicity, we refer to the present value of net benefits flowing from a given investment project as that project's NPV; for concreteness, we refer to the large and small upgrades as the installation of a 400kV and 220kV line, respectively. We assume that the 400kV line is sufficiently large to cover all possible contingencies, but that this may not be true of the 220kV line. Thus, there is an obvious tradeoff between the higher investment costs of the former against the potential unmet demand costs of the latter.

The possible investments are:

A single 400 kV upgrade One possibility is to invest in a single 400 kV line this period, with NPV denoted by $N_{400\text{ kV}}$.

A single 220 kV upgrade Another possibility is to invest in a single 220 kV line this period, with NPV denoted by $N_{1\text{st }220\text{ kV}}$.

Two 220 kV upgrades in sequence Because investing in a 220 kV line this period does not preclude investing in a second 220kV line next period, a third possibility is to invest in a single 220 kV line this period and simultaneously commit to an additional line next period. This has a total NPV of

$$N_{1\text{st }220\text{ kV}} + \frac{E[N_{2\text{nd }220\text{ kV}}]}{1+r},$$

where $N_{2\text{nd }220\text{ kV}}$ denotes the future NPV from installing the second 220 kV line and r is the discount rate.

A single 220 kV upgrade, with the possibility of a second one later A final possibility is to delay the decision concerning the second line until more information is revealed. That is, install the second line if and only if conditions warrant doing so, i.e., $N_{2\text{nd }220\text{ kV}} > 0$. This strategy has a total NPV of

$$N_{1\text{st }220\text{ kV}} + \frac{E[\max\{0, N_{2\text{nd }220\text{ kV}}\}]}{1+r}, \tag{1}$$

The second term is the value of the *expansion option* to subsequently invest in a second 220 kV line. Since this is non-negative, this investment strategy must dominate the single 220kV upgrade (which has NPV equal to $N_{\text{1st 220 kV}}$). Alternatively, the NPV of this strategy can be written as

$$\left(N_{\text{1st 220 kV}} + \frac{E[N_{\text{2nd 220 kV}}]}{1+r}\right) + \frac{E[\max\{0, -N_{\text{2nd 220 kV}}\}]}{1+r}.$$

The expression in large brackets is the NPV from committing now to invest in one 220 kV line this period and a second 220 kV line next period. The remaining term is the value of the *abandonment option* to subsequently reverse the commitment to invest in a second 220 kV line (if, for example, demand turns out to be low). Since the value of the latter is non-negative, this strategy also dominates the strategy of committing to build both lines.

Clearly, only two of these strategies are potentially optimal: a single 400 kV upgrade today, or a single 220 kV upgrade today together with the option to expand next period. From (1), the former is superior if and only if

$$N_{\text{400 kV}} > N_{\text{1st 220 kV}} + \frac{E[\max\{0, N_{\text{2nd 220 kV}}\}]}{1+r}.$$

Rearranging yields the equivalent condition

$$N_{\text{400 kV}} - \left(N_{\text{1st 220 kV}} + \frac{E[N_{\text{2nd 220 kV}}]}{1+r}\right) > \frac{E[\max\{0, -N_{\text{2nd 220 kV}}\}]}{1+r},$$

which highlights the two essential features of the two projects. Firstly, investing in a single 400 kV line exploits the economies of scale of transmission investment: the left hand side quantifies the benefits from making a single large investment rather than two smaller investments. Secondly, investing in sequence creates the option not to undertake the later stage of the project. Put simply, if the benefits from a grid upgrade are less than forecast, the sequential grid upgrade can be interrupted, and future sunk investments avoided. The right hand side of the condition above measures the value of this flexibility. Thus, a 400 kV upgrade is preferred to an immediate 220 kV upgrade if and only if the economies of scale offered by the former are more valuable than the flexibility offered by the latter.

Our model highlights the role of flexibility in determining which of the two upgrade possibilities is superior; although part of this determination (economies of scale) can be captured by standard NPV calculations, the remainder requires consideration of real options. This additional consideration also seems likely to be economically significant; as discussed in Section 2.2, flexibility is most valuable when investments are irreversible and have uncertain benefits, features that are certainly characteristic of grid upgrades.

4 Extending the basic model: transmission alternatives

In the previous section, investment in transmission could be large or small, but it had to begin today. In practice, however, this decision can often be deferred. In this section, we consider the implications of allowing for delay in the *commencement* of a transmission investment programme. The ability to utilise this additional flexibility depends largely on the availability of alternatives and on the speed and extent of the resolution of uncertainty. For example, if a large amount of uncertainty were resolved in a fairly short period of time, there could be considerable value in delaying transmission investment in order to obtain better information about how much investment is actually required.

4.1 Transmission alternatives

Returning to our model of the choice between 220kV and 400kV upgrade projects and allowing for the possibility that transmission investment can be delayed (but not dispensed with altogether, i.e., if neither project begins in the first period, one must do so in the second period), we must also consider the following two strategies.

Do nothing One possible approach is to undertake no grid investment this period. However, this does not preclude investing next period. By delaying investment, more information about the present value of the net benefits from installing 220 kV and 400 kV lines is obtained. Thus, the NPV of doing nothing *this period* equals

$$0 + \frac{E[\max\{N_{400\text{ kV}}, N_{1\text{st }220\text{ kV}}\}]}{1+r}.$$

Invest in transmission alternatives The final strategy we consider also delays transmission investment until more is known about demand and generation investment. However, the penalties for outages mean that delaying transmission investment can be very expensive. Some sort of transmission alternative may thus be needed in the short term, such as building new generation near areas with high demand. The NPV from this approach is

$$G + \frac{E[\max\{N_{400\text{ kV}}, N_{1\text{st }220\text{ kV}}\}]}{1+r}, \tag{2}$$

where G is the net benefit this period from investing in the best available transmission alternative. G is the sum of the benefits this period and the present value of the transmission alternative's 'terminal value' next period, less the construction cost.[9] Assuming G is positive, this dominates the 'do-nothing' strategy.

To determine whether delay is desirable, we need to compare the above investment in transmission alternatives with the 220 and 400 kV upgrades. By (2), immediate investment in a 400 kV line is preferred to investment in a transmission alternative if and only if

$$N_{400\text{ kV}} > G + \frac{E[\max\{N_{400\text{ kV}}, N_{1\text{st }220\text{ kV}}\}]}{1+r}.$$

[9]The terminal value of the transmission alternative depends on the nature of the asset. For instance, if the transmission alternative is removed or redeployed next period, then the terminal value equals the asset's salvage or resale value; if it remains in place, then the terminal value equals the value of the ongoing *incremental* benefits resulting from having the transmission alternative in place alongside either the 220 kV or 400 kV upgrade.

which can be restated as

$$N_{400\text{ kV}} - \left(G + \frac{N_{400\text{ kV}}}{1+r}\right) > \frac{E[\max\{0, N_{1\text{st }220\text{ kV}} - N_{400\text{ kV}}\}]}{1+r}.$$

The expression inside the large brackets on the left hand side equals the present value of investing in a transmission alternative this period and a 400 kV line next period. Thus, the entire left hand side equals the present value of the net benefits from investing in the 400 kV line immediately, rather than committing to its construction one period later. The right hand side equals the value of the option to 'reverse' this commitment and proceed with a 220 kV line instead. Therefore, a 400 kV upgrade is preferred to an investment in transmission alternatives if the earlier arrival of net benefits created by the former is more valuable than the flexibility offered by the latter.

Finally, we compare an immediate 220 kV upgrade with immediate investment in a transmission alternative. Both projects allow the decision-maker to avoid over-investing in transmission assets, since in both cases it can build a single 220 kV line if grid requirements turn out to be low. However, the transmission alternative allows it to exploit all of the economies of scale if the grid requirement turns out to be high (i.e., build a 400 kV line rather than a second 220 kV line). Therefore, the main advantage of the transmission alternative is that it allows exploitation of economies of scale in the 400 kV line if large amounts of grid investment turn out to be needed. Using (1), immediate investment in a 220 kV line is preferred to investment in a transmission alternative if and only if

$$N_{1\text{st }220\text{ kV}} + \frac{E[\max\{0, N_{2\text{nd }220\text{ kV}}\}]}{1+r} > G + \frac{E[\max\{N_{400\text{ kV}}, N_{1\text{st }220\text{ kV}}\}]}{1+r}.$$

which can be rewritten as

$$N_{1\text{st }220\text{ kV}} - \left(G + \frac{E[N_{1\text{st }220\text{ kV}}]}{1+r}\right) > \frac{E[\max\{0, N_{400\text{ kV}} - N_{1\text{st }220\text{ kV}}\}]}{1+r} - \frac{E[\max\{0, N_{2\text{nd }220\text{ kV}}\}]}{1+r}.$$

The expression inside the large brackets on the left hand side equals the present value of investing in a transmission alternative this period and a 220 kV line next period. Thus, the entire left hand side equals the present value of the net benefits from investing in a 220 kV line immediately, rather than committing to its construction one period later. The right hand side equals the value of the option to 'reverse' this commitment and proceed with a 400 kV kV line instead. That is, rather than receiving $N_{2\text{nd }220\text{ kV}}$ from installing a second 220 kV line, $N_{400\text{ kV}} - N_{1\text{st }220\text{ kV}}$ is received instead. This option is valuable because of the economies of scale in grid investment.

To summarize, when considering investment in a grid upgrade versus investment in transmission alternatives that allow the grid upgrade to be deferred, the trade-off is between investment flexibility and earlier receipt of the net benefits of a grid upgrade. If considerable uncertainty were resolved in the first few years of a planned grid upgrade programme (e.g., during the stage 1 period modelled in Section 5), there could be considerable value in building short-term generation capacity to tide the system over until the state of the world is known and then building new transmission appropriate for the state that has been revealed. However, the technical complexities of transmission investment may place significant constraints on this option, a point to which we now turn.

4.2 Time to build

The analysis above assumes that the output from transmission investment becomes available as soon as the decision to proceed is made. In practice, however, transmission investment projects feature lengthy construction times and, prior to construction, lengthy and costly planning and preparation processes.[10] This aspect of transmission investment makes risk surrounding the cost of construction, in both the price of inputs and the length of time required to complete the project, especially important.[11] Additional complications arise because new grid investment (or some transmission alternative) is required before demand reaches a point at which some of it will be unmet. Construction in any grid upgrade must therefore begin sufficiently early to ensure that the completed project is in place at some date prior to that point being reached.

To examine this issue more closely, suppose there are three projects, a, b, and c. Project a will take T^a_{build} years to build. Construction times for the other two projects are defined similarly. Suppose that

$$T^a_{\text{build}} < T^b_{\text{build}} < T^c_{\text{build}},$$

so that project a is the fastest to build and project c is the slowest. Then, assuming the planning stage of all three projects is completed, any one of the three projects can be chosen prior to date $T - T^c_{\text{build}}$, where T is the date at which unmet demand is expected to arise. However, once $T - T^c_{\text{build}}$ has passed, the option to build project c in time to meet the higher demand disappears. At any time between dates $T - T^c_{\text{build}}$ and $T - T^b_{\text{build}}$, projects a or b can begin, but once date $T - T^b_{\text{build}}$ has passed, the option to build project b in time to meet the higher demand is gone. All that is left is project a, and this must be started some time prior to date $T - T^a_{\text{build}}$ if the higher demand is to be met. Therefore, the options for investment diminish as time goes by. The situation is depicted in Figure 1.

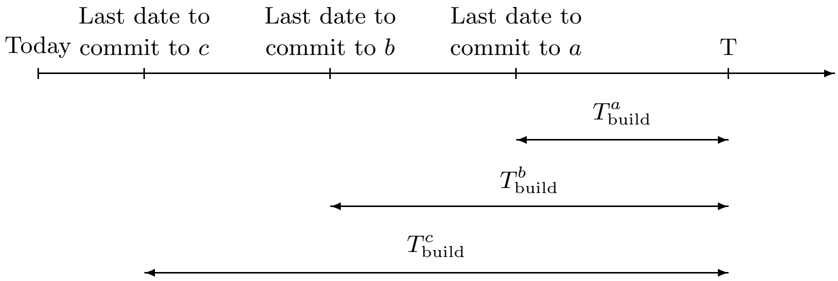
This conclusion is exacerbated by uncertainty, both about construction times and about future demand. If there were no such risks, it may well be optimal to delay investment until the last minute (although earlier investment might be optimal if construction costs were expected to rise). However, when construction times and the required completion date are uncertain, delay runs the risk that the project will not be ready in time. This raises the possibility that the option to defer grid investment will die suddenly if demand grows rapidly, bringing forward the date at which outages will occur without immediate grid investment. This lowers the value of waiting, and thus makes investment delay less attractive.

The decision maker therefore faces a series of decisions regarding whether or not to follow a particular project, e.g., to decide by year $T - T^c_{\text{build}}$ whether or not to build the project with the

[10] For example, see Transpower (2005, Part I, p. 11; Part V, p. 10) for details on the timing and magnitude of expenditure for the 400 kV North Island upgrade.

[11] Pindyck (1993) uses real options analysis to analyze the effect of both of these risks on optimal investment, but in his model the firm does not face a constraint forcing it to meet future demand. Thus, his results are not directly applicable to the GIT. See also Boyle and Guthrie (2003), Evans and Guthrie (2005) and Milne and Whalley (2000) for analyses of constraints on investment timing flexibility.

Figure 1: Investment timing for projects with different construction times



longest construction time. There are several trade-offs to consider in making these decisions. First, waiting defers expenditure and therefore reduces the present value of expenditure. Second, waiting allows decisions to be based on more information about transmission requirements. Third, however, waiting risks losing the option to choose investment projects with long or uncertain construction times.

Uncertain construction times also have another, paradoxical, effect on transmission investment: they make parallel investment in the planning stages of multiple projects relatively more attractive, as this creates the option to switch immediately to the construction of another pre-approved project if construction of the favoured project proves slower than expected (or if demand grows more rapidly than expected).

To detail this last point further, suppose there are two possible projects, labelled a and b, and two periods. We let N_a and N_b denote the present value of the flow of net benefits of the two projects, measured at the time the construction phase begins. In order for project a to be undertaken in the second period, an irreversible investment in 'preparation', costing I_a, must be made in the first period. Similarly, project b can only be undertaken in the second period if I_b is invested in the first period. There may be economies of scope in this preparation phase, in which case spending $I_{ab} < I_a + I_b$ in the first period permits investment in *either* project in the second period.[12]

Suppose that only project a is prepared in the first period. Then the NPV of grid investment equals

$$\text{NPV}_a = -I_a + \frac{E[N_a]}{1+r},$$

reflecting the immediate expenditure of I_a and the expected receipt of $E[N_a]$ in the second period. However, if both projects are prepared, then the NPV is

$$\text{NPV}_{ab} = -I_{ab} + \frac{E[\max\{N_a, N_b\}]}{1+r},$$

reflecting the immediate expenditure of I_{ab} and the receipt of the larger of N_a and N_b next

[12]Of course, in practice it may be optimal to ultimately invest in both projects, in which case there is additional value in undertaking the preliminary stages of both projects.

period; that is, planning for both projects starts this period, allowing the choice of whichever is the better project next period. This strategy is preferred to the first one, of simply preparing for project a, if and only if $\mathrm{NPV}_{ab} > \mathrm{NPV}_a$. The incremental benefit of preparing for both projects is

$$\begin{aligned}
\mathrm{NPV}_{ab} - \mathrm{NPV}_a &= \left(-I_{ab} + \frac{E[\max\{N_a, N_b\}]}{1+r}\right) - \left(-I_a + \frac{E[N_a]}{1+r}\right) \\
&= \frac{E[\max\{N_a, N_b\}] - E[N_a]}{1+r} - (I_{ab} - I_a) \\
&= \frac{E[\max\{0, N_b - N_a\}]}{1+r} - (I_{ab} - I_a)\,.
\end{aligned}$$

The first term in the last line is the value of the *flexibility option* created by preparing for both projects. It has value whenever there is a possibility that project b will turn out to be preferred to project a at the time the final investment decision is made (that is, whenever there is a possibility that $N_b - N_a > 0$). The second term in the last line is the *incremental cost* of preparing for the alternative project b. Thus, preparing for more than one way to meet future demand growth is optimal if the flexibility option created by this preparation is more valuable than the incremental cost. The cost of the option itself (that is, expenditure on the planning phase of the back-up project) can be thought of as a form of insurance premium against the risk of the favoured project disappointing, e.g., if it looked unlikely to be in place in time. In this case, the flexibility option will be most valuable when the back-up project has a short construction time.

5 Putting some flesh on the basic model: Demand and generation uncertainty

Having established the conceptual value of flexibility in transmission investment decisions, we now turn our attention to the more difficult task of quantifying this value in a practically-useful manner. Unlike in our two-period model, the optimal transmission investment decision does not require a simple one-off choice between two competing alternatives. Instead, new information arrives over multiple dates, allowing continual modification of investment plans. In short, actual flexibility in transmission investment is both richer and more complex than it appears in our two-period model.

We suggest a three-step process for explicitly calculating the value of flexibility in transmission investment. First, identify and specify the sources of uncertainty that make flexibility valuable. Second, quantify all possible outcomes associated with the realization of these risks. Third, determine the optimal investment schedule associated with these outcomes, using all information that is available at the time each decision is made.

Although transmission investment is subject to a myriad of risks, it seems reasonable, at least initially, to keep the problem manageable by focusing on a limited number of the most important risks.[13] Uncertainty about future electricity *demand* and *supply* (that is, generation investment) stand out, including their timing, scale and location. If future demand turns out to be higher than anticipated, the ability to increase planned transmission investment is valuable for avoiding the costs of unmet demand; if future demand is unexpectedly low, the ability to mothball planned transmission investment avoids unnecessary expenditure. Similarly, because transmission and generation investments are in part substitutable, unforeseen fluctuations in the latter can have significant implications for transmission investment. For example, if the amount of generation sited near high-population areas turns out to be greater than expected, the need to transmit power from distant sources is reduced and the ability to cut back on transmission investment is valuable.

We assume these two sources of uncertainty are independent of each other, thereby allowing us to deal with them sequentially. We focus first on demand uncertainty.

5.1 Demand uncertainty

The simplest way to quantify demand uncertainty is to specify a particular model, or stochastic process, for demand and then simulate this over some pre-determined period of time T. For example, one might first assume that demand follows a diffusion process, then choose appropriate parameters for this process, and finally use Monte Carlo methods to generate n possible demand paths of length T.

A more difficult task is to determine what investment schedule is implied by a particular demand path. The ideal approach, based on real options theory, determines demand thresholds X_t that determine the optimal investment choice at each date t. For example, if demand is greater than X_t at date t, then the next stage of the planned investment schedule begins, otherwise it does not. In effect, this approach asks the question: "What *should* the decision-maker do at each date t, given the information that is available at that date?" Unfortunately, the optimal value of X_t requires endogenous determination of X_t, a task that Monte Carlo simulation is not well suited to.

A simpler alternative to the above approach is to apply a deterministic investment rule based on an exogenous specification of the critical demand thresholds.[14] In effect, the decision maker looks along the simulated demand path and asks what investment decision it would have made at each date, given the observed level of demand. Although this is only an approximation of real options analysis, it does allow investment scheduling to respond to new information. And, unlike the alternative of perfect foresight, it only incorporates information that is actually available at the time a decision is made. Moreover, to the extent that the deterministic investment rule corresponds to how the decision maker actually behaves in practice, it may provide a

[13] Additional sources of uncertainty can be handled in exactly the same way as those we consider here, so introducing a wider range of risks complicates the analysis without yielding any additional insights.

[14] This is the approach adopted by Transpower (2005).

more realistic estimate of investment value than pure real options analysis (which assumes that decision-makers respond optimally to new information).

Regardless of which of these approaches is used, it is straightforward to apply the GIT. For every demand path, an investment schedule is obtained by applying the chosen rule. For each such schedule, the net market benefit is estimated, with averaging across all sequences providing an 'expected' net benefit.

5.2 Generation uncertainty

Fluctuations in generation investment can also have a significant effect on the present value of the net benefits from grid investment. Given the complexity of the transmission investment problem and the need to keep any model tractable, generation investment uncertainty is probably best captured with some sort of reduced form process. That is, the valuation model should describe the appearance of new generation directly, rather than the underlying factors such as fuel prices, gas discovery, CO_2 costs, technology shocks, policy changes, exchange rates, and so on. Indeed, this is the approach specified by the GIT, which envisages a limited number (five) of scenarios, each of which is described by the amount and location of future generation investment.

In terms of implementing this structure, an important issue is the speed with which the uncertainty inherent in the scenario structure is resolved. For example, if it quickly becomes apparent which scenario applies, the flexibility to adapt the transmission investment programme to this information is particularly valuable. On the other hand, if it never becomes clear which scenario applies, flexibility is valueless since there is no new information to respond to.

We suggest three possible ways of modeling this issue. For concreteness, we assume the period with which the investment decision maker is concerned can be split into three stages: stage 1 (short-term), stage 2 (medium-term) and stage 3 (long-term).[15]

Information arrives quickly and uncertainty is short-lived In this case, all scenarios are initially equally likely, but all of the generation uncertainty is eliminated immediately after the first stage of transmission investment has been completed; after this date, investment proceeds under conditions of perfect foresight about future generation developments. This situation is depicted in Figure 2.

The distinctive feature of this set-up is that when stage 2 investment is undertaken there is no uncertainty about the generation scenario that will arise when stage 3 investment is required. That is, all generation uncertainty is resolved prior to stage 2 investment. Of course, in practice, there is likely to still be uncertainty about future generation investment at stage 2, so this scenario structure is an oversimplification. When choosing the specific stage 1 investment, the decision maker will be conscious of the fact that what it does in stage 1 will affect what it can do in stage 2. Similarly, when choosing the specific stage 2 investment, the decision maker will

[15]In the GIT, these stages correspond approximately to 2010–2015, 2015–2020, and beyond 2020 respectively.

Figure 2: Scenario structure when information arrives quickly and uncertainty is short-lived

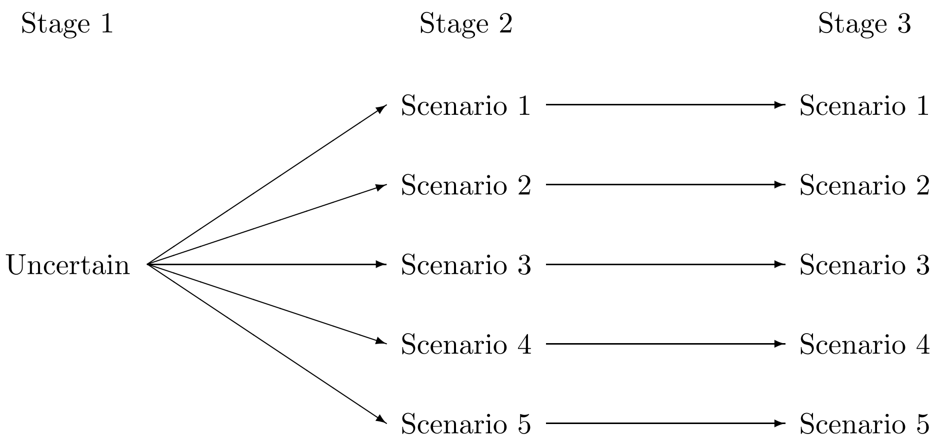
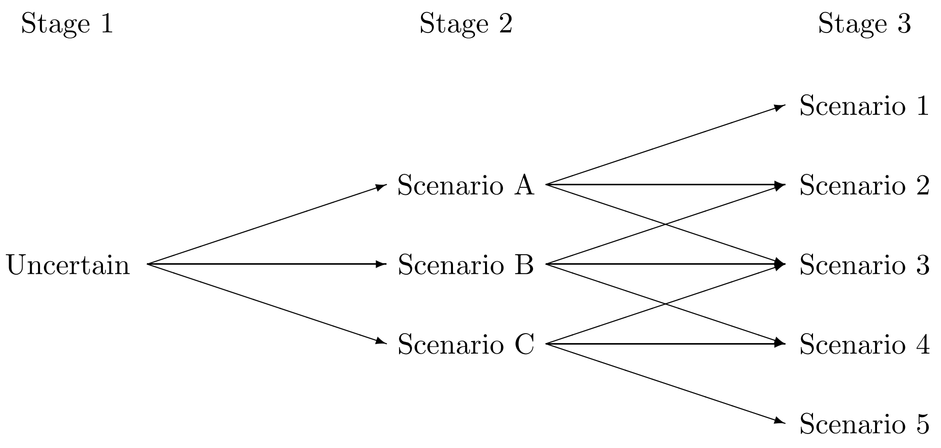


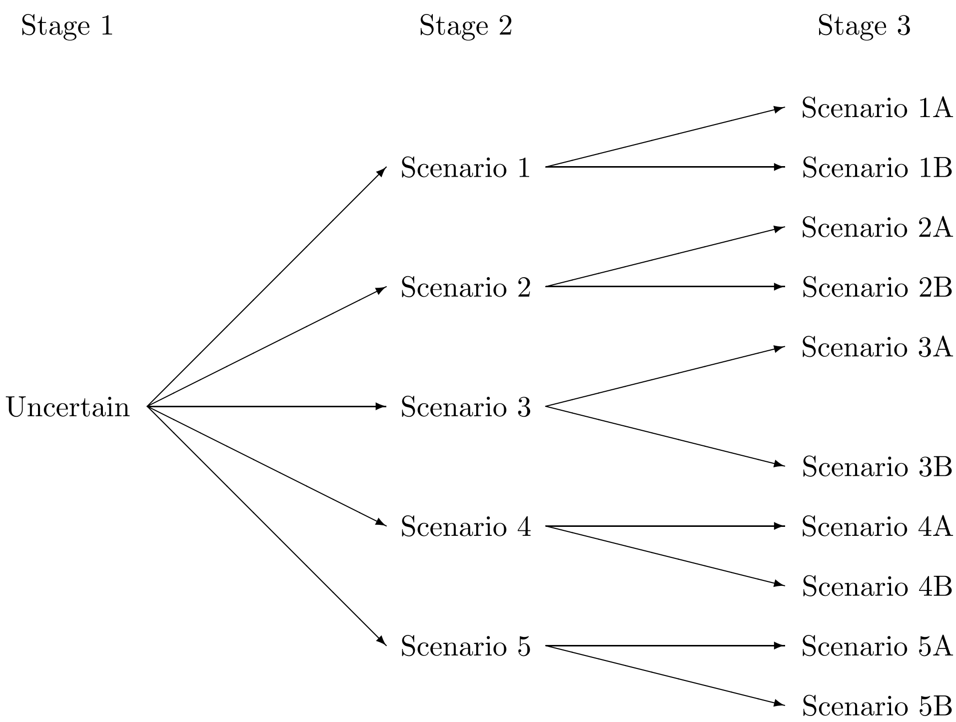
Figure 3: Scenario structure when information arrives slowly



be conscious of the fact that what it does in stage 2 will affect what it can do in stage 3. These dynamic considerations are missing from the scenario structure in Figure 2 because the arrival of information concerning future generation investment is too abrupt.

Information arrives slowly A more realistic possibility is that there will ultimately be five different generation scenarios, but that the precise scenario will not be revealed until stage 3 occurs. Observation of the stage 2 scenario restricts, but does not reveal, the true stage 3 scenario. One possible structure appears in Figure 3. In this case, information arrives more slowly: the decision-maker can really only differentiate between stage 2 scenarios A–C, which provide information about, but do not fully reveal, the stage 3 scenario. For example, if scenario A occurs at stage 2, the decision-maker knows that scenarios 4 and 5 can be ruled out at stage 3, but remains uncertain about scenarios 1–3.

Figure 4: Scenario structure when uncertainty is long-lived



Uncertainty is long-lived A third possibility is to allow for five stage 2 generation scenarios, but also allow for more at stage 3. As a result, there will still be some uncertainty about future generation at stage 2, but less than at stage 1. An example of this is shown in Figure 4. In this case, uncertainty takes a long time to resolve: observation of stage 2 provides information about stage 3, but some residual uncertainty remains. For example, if scenario 1 eventuates at stage 2, then either scenario 1A or 1B can occur at stage 3.

These alternative scenario structures will lead to different valuations of transmission investment projects, although the net outcome will differ from project to project. Relative to the case where all information is revealed at stage 2, the latter two structures have conflicting effects. On the one hand, their incorporation of imperfect foresight lowers project value. On the other hand, undertaking stage 2 investment no longer entails a commitment to stage 3 investment (because more information is revealed at stage 3) and this raises project value.

6 Concluding remarks

In this paper, we have set out a simple analytical framework for incorporating real options in transmission investment decisions. Although only a first step, our discussion has yielded some interesting insights. Uncertainty about future demand and generation growth is an important factor when determining optimal transmission investment. If there is significant uncertainty about future demand, the real options embedded in incremental investment programmes (such as small grid upgrades) or other approaches that defer grid investment (such as the use of transmission alternatives) can be very valuable, potentially outweighing the economies of scale advantage of large upgrades. Offsetting this, however, are the lengthy and uncertain planning and construction times associated with transmission investment. In general, this lowers the value of the flexibility to defer investment, because of the risk that the favoured project may have to be switched to a faster-to-build alternative if demand grows unexpectedly. For this reason, uncertain construction times also encourage 'construction-time diversification'; that is, preliminary investment in multiple investments with different construction times.

One issue that we have not addressed directly is the extent of coordination between generation investment and transmission investment. In our analysis, the appearance of new generation assets is treated as exogenous; that is, current and projected transmission investment does not influence generation investment. However, there is clearly the potential for strong interactions. For example, a strong transmission network creates more opportunities for generation investment, while local generation investment creates opportunities for delaying transmission investment. A social planner, which controls all investment in generation and transmission assets, might invest quite differently from the owner of the transmission network.

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