Draft grid investment test

FINAL DRAFT DISCUSSION PAPER

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Background and objectives

The Part F Transport Rules provide for the Electricity Governance Board, also known as the Electricity Commission (the Board) to approve and publish a draft grid investment test (GIT) for assessment of regulated transmission investments.

The objectives of the GIT suggest that the test should be based on a 'cost-benefit' analysis approach to investment decision-making. The objectives stress that the test should promote economic efficiency, reflect reasonable levels of reliability and promote certainty and facilitation of acceptable outcomes. Fundamentally, the test is concerned with promoting the best project – from the point of view of the electricity sector – for addressing a given need or opportunity, given relevant alternatives.

An important part of defining the test is to recognise that the application of cost-benefit analysis can be controversial if concepts are not clearly defined, so clarity and simplicity in the test are crucial to avoid delays and disputes. The experience of the equivalent to the GIT in Australia has demonstrated the importance of these characteristics.

Regulated transmission investment can take two forms – 'economic' and 'reliability' investments. The former are directed at producing net benefits for the electricity sector through, for example, allowing dispatch of lower-cost plant and deferring new generator plant entry while the latter are directed at maintaining given reliability standards.

Economic investments

The first stage in cost-benefit analysis is to define a 'base case'. Specification of a base case involves describing the present and expected future market environment without the investment or any of its alternatives in place. The inputs and outputs of the transmission project can then be set against the base case to determine the incremental costs and benefits of the project as well as its overall 'net benefits' compared with the base case. Any alternatives to the transmission project can be assessed in a similar way. Alternatives must be projects that would not be likely to go ahead if the proposed transmission project went ahead. Processes for selecting and funding alternatives need to be developed to ensure that they are:

- technically feasible;
- appropriate in type/technology, location and number; and
- likely to be developed by some party – a private proponent, Transpower or the Board – if the transmission option does not proceed.

The projects can then be ranked on the basis of the expected net benefits (or net costs) they confer over and above the base case. A transmission project only meets the requirements of the GIT if it is the highest-ranking project compared to the relevant alternatives.

Reliability investments

Reliability investments are directed towards maintaining reliability standards. These standards can fundamentally take two forms: 'deterministic' and 'probabilistic' standards. Deterministic standards are those specified in terms of technical criteria – for example, a certain level of network redundancy (e.g. 'N-1'). In this case, the value of reliability conferred by the project to the market has not been explicitly valued. On the other hand, probabilistic standards explicitly take account of the probability of customer load being unserved due to some fault or outage, as well as the expected loss of value if that fault or outage occurs. Reliability investments based on probabilistic standards typically refer to a 'target' value of unserved energy, such that if an investment is expected to reduce unserved energy at a cost below the value of that unserved energy, the investment should go ahead (assuming no better alternatives exist). For this reason, reliability investments directed towards probabilistic standards are appropriately assessed as economic investments. While the Board is in the process of considering the development of probabilistic reliability standards, until this process is complete, the GIT should be capable of applying to investments directed towards any type of reliability standards.

For reliability investments directed towards deterministic standards, it may be appropriate to apply 'cost-effectiveness' analysis rather than a detailed cost-benefits analysis. Cost-effectiveness analysis only considers the least-cost option for achieving a certain outcome – in this case a deterministic reliability standard. Nevertheless, even a reliability project directed towards maintaining deterministic reliability standards may produce significant non-reliability benefits (for example, deferred generation entry). If this is the case, the project (and its alternatives) should be assessed under a cost-benefit approach.

Conceptual and modelling parameters

Application of cost-benefit (and to a lesser extent cost-effectiveness) analysis requires clarification over certain key modelling parameters. These and the suggested ways of addressing them are:

- a discount rate for converting future cash flows to current values – this should be based on a discount rate that a private firm investing in the electricity sector would apply;
- the appropriate timeframe for the analysis – this should be 20 years, but with provision for including 'terminal values' for net benefits or costs expected to arise after this time;
- a valuation of unserved energy, to measure the benefits of reducing unserved energy (not relevant in cost-effectiveness analysis) – at least initially, this should be $20,000/MWh. However, the Board could undertake work to obtain up-to-date New Zealand-specific figures;
- the treatment of uncertainty in future market outcomes via 'scenario' or equivalent analysis – scenario analysis should be used to account for uncertainty in future market development. The alternative 'real option'

analysis is unlikely to be worthwhile given the additional complexity and subjectivity it would bring; and

- whether and how 'competition benefits' ought to be included – competition benefits ought not be excluded, but should be modelled according to a transparent and robust methodology.

Practical interaction with Part F

In addition, it is necessary to specify practical matters such as appropriate data sources and a materiality threshold. We suggest that the test should apply to proposed transmission investments above $10 million. Data for the analysis should be sourced in the first instance from the Statement of Opportunities and Centralised Data Set that the Board is required to publish under Part F.

Importantly, as stated above, the determination of appropriate reliability standards is a matter for the Board. The Board is also responsible for approving reliability investments. Therefore, at least for the present time, the GIT must neither preclude nor pre-empt development or application of either deterministic or probabilistic standards. Rather, the GIT should be capable of applying to reliability investments regardless of what standards may be developed.

1 Introduction

As part of the development of this regulatory framework as set out in the Part F Transport Rules, the Electricity Governance Board, also known as the Electricity Commission (the Board) is required to approve and publish a draft grid investment test (GIT). The GIT is intended to provide the Board with a systematic basis for assessing the economic merit of new transmission investments that Transpower seeks to recover the costs of through regulated charges.

This Discussion Paper by Frontier Economics (Frontier) describes the basis of a GIT and how it could be applied to assess the economic merit of proposed transmission investments. In developing a proposed GIT, Frontier has sought to establish a framework that is transparent and robust and as straightforward as possible, and can be applied systematically to assess whether grid investment is worthwhile. This is a difficult set of aims to achieve.

1.1 BACKGROUND TO THIS DISCUSSION PAPER

The New Zealand electricity transmission network has seen little new investment in the last 10 years. Transpower is now of the view that significant investment in the grid is needed over the next 10-15 years to maintain security and reliability standards.

The Government is concerned to ensure that Transpower only undertake prudent expenditure on developing and augmenting the network, to ensure resources are not wasted and prices charged to customers are not excessive. As Transpower does not operate in a competitive market, some form of regulation is required to govern Transpower's expenditure.

In principle, it would be a relatively straightforward task to describe the concept of a GIT and its underlying economic principles, both of which would be broadly acceptable to most stakeholders. However, experience in Australia has shown that there are many alternative ways of interpreting these principles and quantifying inputs and outputs, which can lead to variable results. These problems can be largely avoided and more certainty given to the market by making the GIT more prescriptive. This inevitably results in a more detailed, apparently more complex test. However, the reality is that unless these complexities are addressed upfront, they are likely to arise in the course of applying the test.

This Discussion Paper errs on the side of highlighting key controversies and addressing complexities up front, in order to promote greater market certainty and a more comprehensive debate on these issues before the test is applied in practice. However, this is not to suggest that all possible complexities have been foreseen in this Discussion Paper.

1.2 STRUCTURE OF THIS PAPER

This Discussion Paper is structured as follows:

- Section 2 briefly describes the policy context for the development of the GIT.
- Section 3 sets out the framework for the development of the GIT, reflecting principles of cost-benefit analysis and the objectives contained in Part F.
- Section 4 describes the principles for the assessment of economic investments under the GIT.
- Section 5 describes the principles for the assessment of reliability investments under the GIT.
- Section 6 considers the detailed modelling parameters of the GIT, including variables such as the discount rate, value of unserved energy, competition benefits and uncertainty.
- Section 7 discusses some of the practical implications of the interaction of the GIT with Part F requirements.

This document is supported by a number of annexes:

- Annex 1 is a draft terms sheet containing the key provisions of the draft GIT.
- Annex 2 provides a brief history of the grid and plans for future investment.
- Annex 3 explains key economic concepts that support the GIT.
- Annex 4 briefly outlines real options theory.
- Annex 5 sets out all the issues for consultation raised in this paper.
- Annex 6 lists references.

2 Policy context

Transpower has stated that it needs to undertake significant investment in the grid over the next 10-15 years to maintain adequate levels of security and reliability. In order to assess the merits of proposed transmission investment, criteria are required to ensure that transmission investments that do proceed most economically meets the needs of the market.

2.1 MARKET-DRIVEN VERSUS REGULATED TRANSMISSION INVESTMENT

The nodal prices posted in the New Zealand wholesale electricity market were intended to encourage market participants or other private investors to develop new generation and transmission assets as signalled by market prices. However, there have been few, if any, instances around the world where 'market-driven' transmission investments have taken place, let alone be commercially successful.

In the course of developing new governance arrangements for the New Zealand electricity industry, the Government has put in place rules to ensure that transmission investment is efficient and maximises net benefits to network users, given the available alternatives.

2.2 GIT AS A COST-BENEFIT ANALYSIS

The GIT objectives outlined in Part F of the Transport Rules suggest that the test should incorporate a form of cost-benefit analysis. This approach aims to ensure that only investments that are net beneficial to the market are undertaken.

Broadly speaking, cost-benefit analysis involves comparing a potential investment project with the situation when the project is not undertaken (the *base case*) to determine whether the project offers overall net benefits. The difference between discounted benefits and discounted costs – the net market benefit – is an indication of how valuable an investment project is to society and whether it should be undertaken.

Importantly, the identity of the 'winners' and 'losers' of an investment is not relevant to a cost-benefit analysis. From an overall efficiency perspective, what matters is the overall net benefit that the electricity sector gains from the project, not how who pays for it. If the Government is concerned with the (negative) effects on certain sections of the community arising from a transmission project, it could always apply policies to compensate these adversely affected groups, perhaps from the proceeds earned by the project 'winners'. However consideration of such reallocation mechanisms are not the subject of this paper.

2.3 TRANSMISSION PRICING METHODOLOGY

The GIT focuses on the sector-wide benefits and costs of transmission investment. If the GIT shows that proposed transmission projects are net beneficial, the Board would use the results of this analysis to determine whether Transpower is allowed to recover the associated project costs from its customers.

However, the GIT does not say *how* the costs of these projects should be recovered through regulated transmission charges. This issue is dealt with in a related paper produced by Frontier, *Transmission pricing methodology – Options and guidelines*.

2.4 SCOPE OF APPLICATION OF THE GIT

Under the regulatory framework it is not intended that every investment made by Transpower will be subject to the GIT. This would be too onerous. Only investments or related groups of investments that exceed a materiality threshold will be considered under the GIT. Investments that fall below this threshold will be included in Transpower's regulated asset base and recovered through transmission charges. The efficiency of these investments will be scrutinised by the Commerce Commission on a periodic basis. This means that there will be some check on the prudence of investments that are not assessed under the GIT.

3 Part F and cost benefit analysis

The draft GIT is derived from conventional principles of cost-benefit analysis, in accordance with the objectives set out in Part F of the Transport Rules.

Under a cost-benefit analysis, expenditure on an investment is considered worthwhile if, when compared to a base case, its (discounted) benefits exceed its (discounted) costs. If there are competing projects that produce similar outcomes over similar time scales, the option that produces the highest net economic benefits should be chosen.

This section summarises the key principles that should be followed in undertaking such an analysis and reviews the objectives of the GIT as they are described in Part F.

3.1 OBJECTIVES OF THE PART F GRID ECONOMIC TEST

In order to understand how the broad principles of cost-benefits analysis ought to apply in the development of the specific details of the GIT, it is necessary to consider the test's objectives as set out in Section III of Part F (**Figure 1**).

Figure 1: Objectives of the GIT

The Board must have regard to the following objectives in developing, and in any subsequent review of, the GIT:

6.3.1 *promoting economic efficiency (including energy efficiency) in transmission and the wholesale electricity market;*

6.3.2 *as far as practicable reflecting the interests of end use customers in ensuring a reliable transmission system having regard to the cost to end use customers;*

6.3.3 *reflect a reasonable economic assessment of the balance between different levels of reliability and the expected value of energy at risk;*

6.3.4 *enabling selection of transmission upgrade options that maximise the total net benefits to those who produce, distribute and consume electricity after taking into account transmission alternatives;*

6.3.5 *promoting certainty for investment in transmission, generation and transmission alternatives and investment contracts;*

6.3.6 *facilitating outcomes acceptable to Transpower and designated transmission customers.*

The implications of these objectives are briefly discussed below.

3.1.1 Promoting economic efficiency

Clauses 6.3.1 and 6.3.4 indicate that the test should promote economic efficiency in the wholesale market and transmission. Economic efficiency is typically defined in three ways:

- *productive efficiency* is aimed at ensuring that production of a given output occurs at least cost, taking in account the existing quantity and cost of resources;
- *allocative efficiency* focuses on charging customers cost-reflective prices to ensure resources are allocated to their highest valued use; and
- *dynamic efficiency* relates to promoting efficient investments in order to produce the greatest net benefits over time.

In the context of cost benefit analysis, the cost of inputs is given by their *opportunity cost* – that is the value forgone by their next best use. In practice, this is often difficult to observe, so the price paid for the inputs is commonly used.

Outputs ought to be valued at the *willingness to pay* of customers. Therefore, at a high level, the pursuit of efficiency suggests that the grid test should seek to maximise the sum of *consumer surplus* and *producer surpluses* in the electricity sector over time where:[1]

- the *consumer surplus* is the difference between what consumers are willing to pay for something and the price they must pay; and
- the *producer surplus* is the difference between the price producers receive for something and the opportunity cost of producing it (i.e. their 'economic profit').

The basis of decision making in cost-benefit analysis is that projects should be selected on the basis of the net combined consumer and producer surplus they produce. The project amongst the alternatives that produce the largest net combined increase in consumer and producer surplus ought to be the project that is chosen.

Focus on the electricity sector

Clauses 6.3.1 and 6.3.4 of the Part F Rules imply that the relevant resources, values and costs that need to be taken into account to promote efficiency are those that arise in the electricity industry and not across the economy at large. This is a well established principle in cost-benefit analysis and is appropriate.

Therefore, whilst the GIT must take into account broader matters than would be required by a private business in considering a project, the analysis under the test should exclude impacts on other industries. This rules out wider, second and subsequent rounds effects, say, the positive benefits for industry arising from energy cost reductions, which may be the result of a grid investment. As

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1 Annex 3 illustrates the concept of a consumer and producer surplus.

suggested earlier, the distribution of gains and losses throughout the community are not considered in cost-benefit analysis, which is designed to determine whether, overall, a project delivers net benefits.

The intuition behind this approach is that it reflects a judgement about the appropriate level of 'investment' in project analysis, given this is costly and must inevitably be assessed in the context of other (subjective) considerations. Such a limitation is therefore consistent with promoting efficient regulatory processes.

Transmission alternatives

In developing the GIT, it is generally assumed that the economy is operating in a productively efficient manner. For example, it is assumed that businesses that offer alternative projects would behave rationally and efficiently. In this regard, the form of the GIT itself should have little effect on the incentives of generators, distributors, retailers or end customers to produce their respective outputs more cheaply. However, the test will have important implications for the cost at which Transpower provides transmission services.

The requirement in clauses 6.3.1 and 6.3.4 of Section III (and elsewhere in Part F) to consider transmission alternatives (such as generation and demand-side management/energy efficiency (DSM) options) is intended to ensure that lower cost alternatives to a transmission investment (that produce similar benefits) are taken into account in determining whether a grid investment should go ahead.

For example, it maybe cheaper to build a new local generation plant to supply electricity to the Christchurch area than to augment existing transmission lines from the Waitaki Valley. That is, providing that certain technical specifications are met (reflecting the objectives – that is, desired outcomes – of the investment), 'embedded' generation, distribution network augmentation or DSM options may also deliver similar outcomes as a transmission investment. To the extent that the outcomes are similar (in terms of form and time scale), the framework should be capable of considering a range of technical solutions to meeting the investment objective on an even-handed basis.

3.1.2 Reflecting preferred or reasonable levels of reliability

Part F requires the GIT to be applied to identify appropriate 'economic' and 'reliability' investments:

- economic investments primarily deliver benefits in the form of cost savings to the electricity sector, such as reducing transmission constraints and allowing lower-cost plant to be dispatched; and
- reliability investments are primarily directed at maintaining grid reliability standards and good electricity industry practice.

In practice, many investments provide both economic and reliability benefits, and the dividing line may not be clear-cut.

Economic versus reliability investment

The grid test objectives indicate that the test should take account of all the relevant benefits and costs of an investment, as measured by the sum of consumer and producer surpluses in the electricity industry. However, at a more practical level, it may be appropriate to include different types of benefits and costs in the analysis according to whether the investment under consideration is an economic or a reliability investment:

- economic investments provide a broad range of benefits. Therefore, all relevant and material costs and benefits should be considered.
- reliability investments are primarily directed at maintaining grid reliability standards and good electricity industry practice. Depending on the nature of the standards, reliability investments might lend themselves to a simpler and more limited form of analysis.

Interaction between reliability standards and the GIT

Part F envisages a significant interaction between the development of reliability standards and the GIT:

- the GIT is to be utilised by the Board in developing reliability standards (Section III, clause 6.2.1); and
- the Board may only approve a reliability investment that 'meets the requirements of the GIT' (clause 13.4.1).

Satisfying both of these obligations involves some circularity. However, the GIT can be used to guide the setting of reliability standards by considering the costs of different standards. Section 7.2 describes a staged approach for achieving these objectives.

3.1.3 Net benefits

Clause 6.3.4 of Section III focuses on those investment alternatives that produce the highest net benefit – benefits minus costs – to consumers and producers. The nature of benefits and costs that ought to be taken into account for a particular project are discussed below in Section 4.3.

As indicated at the beginning of this Discussion Paper, there is a question about how prescriptive the test needs to be in terms of defining, in advance, the precise variables making up benefits and costs and how they should be measured.

It is unlikely to be desirable to draft the test in a way that provides little or no latitude for the Board since this could result in potentially important (but unforeseen) benefits or costs being excluded. However, leaving the test too general exposes the test to wide interpretation, which could result in greater uncertainty and additional costs to the market.

3.1.4 Promotion of certainty and facilitation of acceptable outcomes

Clauses 6.3.5 and 6.3.6 of Section III recognise the long-lived nature of transmission investment and the need for both Transpower and private sector parties to undertake investment in transmission, generation and other projects within a transparent and consistent longer-term framework. The greater the uncertainty in the drafting and application of the GIT, the less likely it is that a predictable investment climate will emerge. This would support reasonably specific characterisations of, for example, the modelling that should be undertaken, key costs and benefits, the selection of alternative projects and ways of handling uncertainty. Within this framework of specific guidelines, an open and transparent process for developing input assumptions for the test is also likely to lead to improved and more acceptable outcomes.

3.2 RELEVANCE OF THE AUSTRALIAN REGULATORY TEST

The Australian Competition and Consumer Commission (ACCC's) 'regulatory test' is a grid cost-benefit test that was first published in December 1999 and was applied to a number of transmission projects, including the 'SNOVIC 400' (400 MW upgrade from New South Wales to Victoria), the proposed 'SNI' 250 MW interconnector from New South Wales to South Australia and various reliability augmentations within State networks.

The regulatory test has a long and complicated history, with much debate and dispute over its key terms. For example, the SNI application of the test was appealed to the Australian National Electricity Tribunal, where a number of key terms in the test were dissected and discussed, and again in the Supreme Court. Following the Tribunal's decision, the ACCC consulted with the market to determine how the test should be amended to improve clarity and functionality. In March 2004, the ACCC published a draft revised test for stakeholder comments. It is highly likely that uncertainty over the terms of the test has led to inefficient outcomes.

The experience of the development and application of the regulatory test is extremely valuable in guiding the development of the GIT. In particular, the ACCC's draft revised test attempts to avoid ambiguities and pitfalls that the Board would also seek to avoid. Further, the objectives of the grid test in Part F are very similar to the approach of the regulatory test. Indeed, the sample test contained in Annex 2 of the Ministry of Economic Development's consultation paper on Part F appears to be substantially based on the Australian regulatory test.[2]

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[2] Ministry of Economic Development, *Draft Transport Rules (Part F of the Electricity Governance Rules 2003), Consultation Paper*, 4 November 2003.

Therefore, where appropriate, this paper draws on the experience and lessons learnt from the regulatory test in developing the proposed draft GIT.

3.3 STEPS OF COST-BENEFIT ANALYSIS

Taking together the above points, undertaking a standard cost-benefit analysis requires the following steps to be undertaken:

- Step 1: A 'base case' is defined that describes how the relevant industry would operate and expand in the absence of a proposed investment or its alternatives. This is not necessarily a 'do nothing' case. In the event that a transmission project does not go ahead, it may be that a combination of generators and DSM options would be developed instead.
- Step 2: Describe the nature of project inputs and outputs.
- Step 3: Identify all plausible alternative projects that produce equivalent outcomes/services.
- Step 4: Quantify the project inputs and outputs, having developed sound analytical tools to do so.
- Step 5: Compare and rank the net benefits of the project and its alternatives.

The remainder of this Discussion Paper describes, in more detail, the issues associated with each of these steps.

4 Economic investments

This section focuses on important issues in the evaluation of economic investments, such as the definition of the base case, project alternatives and the nature of benefits and costs. For these types of investments, as opposed to some reliability investments (Section 5), the GIT ought to include consideration of a range of costs and benefits that go towards determining the net benefit of the investment.

4.1 ESTABLISHING THE BASE CASE

The GIT requires the identification and specification of a base case as the foundation for a comparison of alternative projects. This is because the incremental costs and benefits of a project or its alternatives can only be understood when compared with the case where the project is not undertaken.

4.1.1 Base case and market development scenarios

The base case describes the status of the electricity industry as it exists and is likely to exist in future *without* the project in question. This can then be compared with the likely status of the industry *with* the project, in order to determine its incremental benefits or costs.

A project only meets the requirements of the GIT if it is shown to be the best project (out of a range of alternatives) when compared against the base case. The base case does not necessarily mean the status quo going forward. Because transmission investments are long-lived and consequently the timeframe for analysis is lengthy, the base case must represent a realistic description of the situation and a 'best guess' of how the future will unfold without the transmission project.

Current state of the world

The types of current or existing variables that should be incorporated in the base case to enable an appropriate assessment and comparison of the costs and benefits of projects are:

- the current size and location of customer loads;
- the current location, size, cost and operating characteristics of existing generation facilities (and DSM projects);
- the topology of the transmission network, including capacities and constraints of key transmission lines;
- current ancillary services costs and transmission losses; and
- estimates of key decision variables, such as the value of 'unserved energy'.

Future state of the world

In order to describe plausible future states of the world with and without a project, a 'market development scenario' must be developed for the base case and for the relevant projects that need to be assessed and compared. A market development scenario contains assumptions about a number of variables, including:

- the expected magnitude, nature (shape), timing and location of load growth (demand-side development); and
- the size, location, timing and costs of generation, transmission and DSM projects going forward (supply-side development).

The benefits and costs of an augmentation will partly depend on how it affects future investment in generation and transmission and how it affects load growth (if at all), in other words, how it affects the market development scenario.

In order to ensure that any reliability benefits of an economic investment are taken into account, the base case market development scenario used to assess the investment must ensure that any grid reliability standards, however specified, are satisfied.

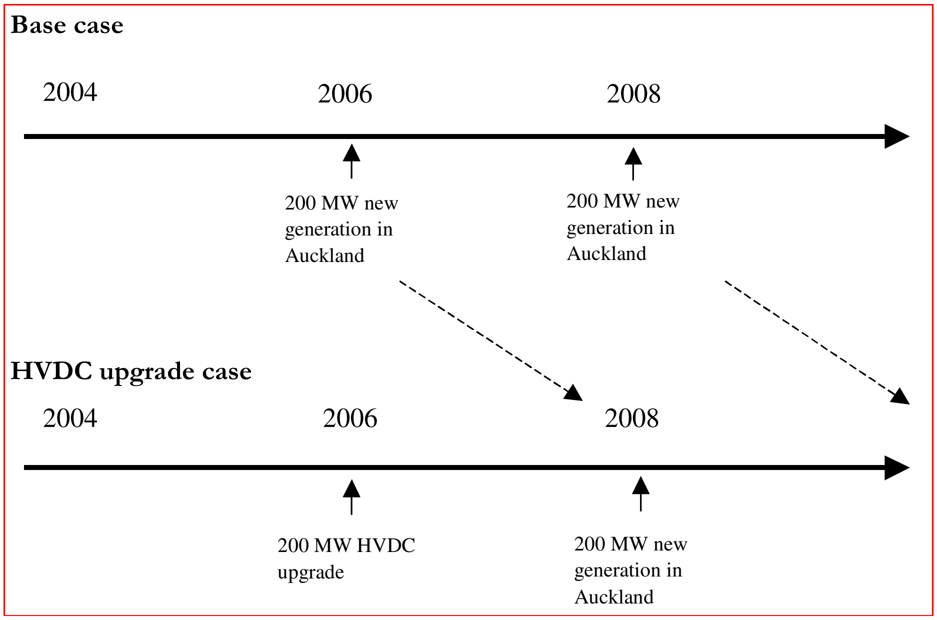
An example

For example, consider a hypothetical transmission augmentation such as an upgrade of the HVDC link. In order to identify and calculate the benefits and costs of this augmentation, it is necessary to first set out what would happen in the market if it did not go ahead.

It may be that, in the absence of the upgrade, additional generation would be developed close to Auckland. Such generation would be part of the base case market development scenario and some of the benefits of the proposed augmentation would arise from the deferral or avoidance of this predicted generation investment. Similar analysis must then be conducted for alternative projects – for example, DSM options in Auckland may also defer the need for some new generation, which would again be counted as a benefit of the DSM.

Figure 2 below illustrates how market development scenarios for the base case and state of the world with the project (the project case) are relevant to the identification of costs and benefits.

Figure 2: Market development scenarios for the base case and the project case



In this hypothetical example, the HVDC upgrade has the effect of deferring the 200 MW generator in Auckland by 2 years, from 2006 to 2008. This deferral will reduce the cost of the 200 MW plant in present value terms. This cost saving from deferred investment is one of the benefits of the HVDC upgrade. For a fuller analysis, the expected deferral of the 2008 generator in the base case would also need to be taken into account.

Issues for consultation

Comments are invited on the most appropriate method for establishing the base case against which Transpower's proposals would be assessed.

4.1.2 Content of market development scenarios

A number of assumptions about both demand and supply side of the market will need to be made in preparing market development scenarios.

Demand forecasts tend to be readily available, although several (high, low, medium) forecasts may need to be considered to account for uncertainty (see Section 6.4). However, information on the likely development of the supply-side of the industry is often more difficult to obtain. In New Zealand this is further complicated by uncertainty about future hydrological conditions and the availability of low-cost fuel sources and difficulties in securing consents to develop new plant and transmission corridors.

Committed, anticipated and modelled projects

The supply side of any market development scenario can be comprised of three different types of projects:

- *Committed projects* are actual proposed projects that satisfy a number of criteria indicating that they are extremely likely to proceed in the near future, for instance:
  - land has been acquired for construction of the project;
  - planning consents, construction approvals and licences have been obtained;
  - construction has begun or a firm commencement date has been set;
  - contracts for supply and construction have been finalised; and
  - financing arrangements must be largely completed.
- *Anticipated projects* satisfy all but one of the criteria for committed projects. These are actual proposed projects that are not as certain, but are still considered likely to proceed.
- *Modelled projects* are 'generic', more speculative projects that are assumed to enter the market on some basis – most likely in response to price signals, that is, when it is profitable to do so.

Committed and anticipated projects are those whose nature and timing is not expected to change greatly as a result of the development of a proposed project. Committed and anticipated projects should be similar in all the relevant market development scenarios (i.e. the base case and the project cases) and benefits from deferring such plant are unlikely to arise. On the other hand, modelled projects may change significantly in timing or size as the result of an augmentation or alternative project. Therefore modelled projects are likely to differ from the base case to the project cases.

Development of modelled projects

A key question in the derivation of market development scenarios is how 'modelled projects' – for instance, new generation investment or DSM – are assumed to occur, since changes in the timing, location and size of modelled projects often constitute significant costs and benefits of a project and its alternatives. There are two ways in which the timing and characteristics of modelled projects can be determined:

- on the basis of an economic least-cost expansion plan for satisfying forecast demand and reliability standards; or
- with reference to expected future price levels.

The first approach is to assume modelled projects occur in the same way and in the same timeframe as they would in a competitive market, the outcomes of which would be broadly consistent with the outcomes of an efficient centrally planned system.[3] In turn, this can be approached in two ways:

- new generation capacity or DSM options can be added to meet a pre-determined reliability criteria in the least cost manner. This would be done using a standard system planning model; or

- new generation capacity or DSM options can be added when the price is sufficiently high to commercially justify the investment in the context of a perfectly functioning market.

The first approach would need a pre-determined reliability criteria to be established and the second would need to have an exogenously determined measure of the value of unserved energy or a Value of Lost Load (VoLL), to reflect the 'price' that would prevail when instantaneous demand cannot be fully met. This would drive the returns of new generation or DSM investment.

For example, in the Australian National Electricity Market (NEM) there is both a reliability criterion and a VoLL. The reliability criterion is a measure of unserved energy set by the Reliability Panel. More specifically, the unserved energy limit is 0.002% of total energy demand within a region. Therefore, new 'reliability' plant could be assumed to enter the market when this criterion was expected to be breached. This criterion therefore does not explicitly take account of the value of the unserved energy. Nonetheless, VoLL is set at A$10,000/MWh in the NEM and there is not necessarily any consistent relationship between the reliability criteria, VoLL and the cost of building new plant. In the NEM this could mean, and probably does mean that the reliability criteria 'cuts in' before the price in the competitive market (influenced by the VoLL) would justify expenditure on new plant to maintain reliability levels.

In spite of these shortcomings, the advantage of these exogenously and pre-determined parameters is that modelling the 'market development scenarios' becomes a relatively straightforward, well-understood and replicable process. This promotes consistency and certainty in the modelling and analysis. If this approach is to be followed, some care is required to ensure that the reliability criteria and VoLL are internally consistent, unlike the case in Australia.

The alternative is for modelled projects to be assumed to occur in a more 'realistic manner', that is, having regard to the fact that the market is not perfectly competitive. However, modelling market entry on this basis is a much more subjective and difficult exercise and hence harder to replicate. Market power may lead to firms implementing any of a wide range of bidding and investment strategies, resulting in a wide range of outcomes. The problem is that the corresponding modelling exercise may predict many different price outcomes in

[3] The two should in theory yield similar outcomes, because investors in a perfectly competitive market do not make economic (more than necessary) profits and are price-takers.

the wholesale market, each of which could potentially trigger a different modelled project. This complexity reduces the transparency of the process and the robustness of the results, and may detract from the acceptability of grid test outcomes.

Even if both perfectly competitive/least-cost and realistic/market-driven approaches are considered, the question becomes whether equal weight should be placed on both approaches, or whether only one or another approach should be given greater emphasis. The preferred option adopted in this paper is for least-cost modelling to be the standard approach, with a 'realistic' bidding approach to be considered as a matter for 'sensitivity' testing.

Types of modelled projects

The formulation of market development scenarios is likely to present special difficulties in New Zealand. The lack of significant unexploited generation fuel sources in New Zealand implies that it is difficult to predict types of future generation investment and where future increments of new generation are likely to be located. This makes the locational element of market development scenarios difficult to model. That is, the approach that has been adopted in the NEM – the use of generic 50MW gas turbines – may not be appropriate in New Zealand. Sensitivity analysis (or another approaches for addressing uncertainty) will be required to assess the quantitative implications of uncertainty in relation to the types of modelled projects.

Issues for consultation

Comments are invited on the following issues in relation to the construction of the market development scenarios:

(1) Whether the market development scenarios should include committed, anticipated and modelled projects for both the base case and the case of the investment (and its alternatives), as defined above.

(2) Whether the market development scenarios should be based on least-cost expansion, with alternative scenarios also considered, or whether they should take account of the fact that the market is not perfectly competitive, and if so how.

(3) The types of modelled projects that are appropriate for New Zealand.

4.2 ALTERNATIVE PROJECTS

The base case is the foundation for determining the benefits and costs of a proposed project under the GIT. However, Part F requires that alternatives to the transmission augmentation must also be considered. For example, taking the hypothetical HVDC upgrade described above, an alternative might be a DSM project in Auckland. There are two ways non-transmission alternative projects could arise:

- Transpower could publicise its application of the GIT and a private proponent could come forward with an alternative project; or

- Transpower or the Board could 'manufacture' a non-transmission project for comparison.

In either case, in specifying exactly which alternatives need to be considered, it is clear that only options that are technologically feasible are relevant. Further, alternatives under the GIT should be projects that would *not* be developed if the transmission project went ahead – for example, projects that are 'committed' or 'anticipated' cannot be alternatives; they are better regarded as part of the base case or sensitivities. However, there are a number of other issues that require more detailed consideration.

4.2.1 Technology of alternatives

Part F defines "transmission alternatives" as "alternatives to investment in the grid, including investment in local generation, energy efficiency, demand-side management and distribution network augmentation set out in Part F".

This appears to suggest that alternative *transmission* projects, including both regulated and contracted transmission investment, may not need to be considered. However, Transpower could – in order to maximise the size of its regulated asset base and hence its regulated return – have an incentive to put forward a more expensive transmission option, even though a cheaper transmission alternative may exist.

In Australia, the selection of appropriate transmission alternatives was the subject of dispute in the SNI appeal. The relevant transmission company, TransGrid, chose to put forward one project ('SNI') when, it was argued by some, that another project ('unbundled SNI') may have provided similar gross benefits at a lower cost. The key criterion for alternative (transmission and non-transmission) projects suggested by the ACCC in its recent draft decision on the regulatory test was "commercial feasibility", which refers to whether a market participant, acting rationally, would have a sufficient economic incentive to construct the project.

However, in New Zealand, Part F provides for the Board to direct Transpower to consider other transmission options as both reliability (clause 13.3.3.3) and economic (14.3.2.2) investments. Whilst there is no requirement on Transpower to proactively undertake this analysis in advance of submitting projects to the Board, and there is no obligation under the Rules for Transpower to modify its proposed investments following Board direction, the Board's ultimate power to reject investments would provide it with substantial leverage in this respect. To reinforce this, the GIT should clarify that Transpower should, as a matter of course, consider a range of appropriate transmission augmentation options, with the number depending on the cost magnitude of the proposed augmentation.

Issues for consultation

Comments are invited on whether Transpower should be required to consider a range of transmission alternatives as well as non-transmission alternatives.

4.2.2 Similarity of alternatives

Alternative projects should be reasonably comparable to the investment under consideration. This requirement may be straightforward to apply for reliability investments, if the basis for the project is the satisfaction of a particular grid standard at a particular location at a particular time.

However, geography and timing may be more of an issue for economic investments, where there is no unambiguous need for the investment in the sense that no technical network criteria have been breached. One approach could be a 'substitutability' criterion, such that projects are treated as alternatives where the development of one would 'significantly impact' on the gross benefits of the other(s).[4]

The problem with this criterion is that the subjectivity is effectively transferred from the identification of 'alternatives' to an assessment of 'significantly impact', a variable that may require more analysis or modelling but may add little in terms of practical assistance to the applier of the test.

A more commonsense approach would focus on options that provided 'similar' outputs at the same nodes over a 'similar' timeframe, with the consultation process and Board input used to ensure Transpower made reasonable assumptions. This 'similar output' approach is simpler to apply since it relies on a more qualitative assessment but, for this very reason, is potentially more arbitrary. On balance it is considered that the 'similar output over a similar time frame' approach is best suited to New Zealand's requirements at this time – that is, to promote simplicity and practicality.

Issues for consultation

Comments are invited on the whether alternatives should be identified in terms of 'substitutability' criterion or whether they are identified according to whether the alternatives provide similar outputs over a similar timeframe.

4.2.3 Number of alternatives

Undertaking the GIT is likely to be a costly and resource-intensive exercise. It is therefore desirable to limit the number of alternatives to ensure that analysis costs are commensurate with the overall benefits at stake and the problem remains tractable. If this is not done, some stakeholders that oppose a transmission investment may find it worthwhile to suggest a large number of 'alternative' projects in order to delay and confuse a project assessment.

Ideally, the number of alternatives considered as part of a grid test assessment would depend on several factors, such as the dollar value of the augmentation being assessed, the nature and number of realistic alternatives available and the urgency of the investment. Such factors could be incorporated in the test, although it would be difficult to formularise them.

4 For instance, extending a gas pipeline could be viewed as a substitute for reinforcing transmission lines required to evacuate power generated by gas-fired power stations.

Issues for consultation

Comments are invited on the following issues in relation to the number of alternatives to be considered:

(1) Whether the number of alternatives to be considered in GIT for any one project should be limited.

(2) If the number of alternatives is to be limited, the basis on which this should occur.

4.2.4 Funding of alternatives

A key issue for the selection of transmission alternatives under the GIT is how they are to be funded if they prove to be the best project. Some entity is required to either pay a proponent to develop the option or enter into a contract with a developer for the non-transmission option.

There are two key options for the role of funding and contracting transmission alternatives:

- Transpower; or
- the Board.

In the first case, changes may be required to Transpower's enabling legislation and Statement of Corporate Intent to empower and either oblige or incentivise it to develop transmission alternatives where they are the best option available. Transpower's regulated revenue cap would also need to be adjusted to allow it to recover the cost of developing or paying third parties for transmission alternatives where they are most efficient.

In the second case, changes to legislation would probably be required to enable the Board to investigate, develop and fund transmission alternatives itself.

There are likely to be a range of other issues that would arise in the funding of transmission alternatives. The Ministry of Economic Development flagged some of these issues in its consultation paper and stated a preference for Transpower to undertake the contracting role.[5] The Ministry also suggested that the Board considers these issues as a medium term priority. The discussion in this paper is intended to be a first step in assisting the Board in the fulfilment of this task.

In any case, unless and until arrangements for funding transmission alternatives are established, non-transmission options must be "real" – that is, be considered reasonably likely to go ahead in the absence of the proposed transmission project. This will ensure that transmission projects will only be rejected where there is a strong likelihood that superior alternative projects will actually go ahead. This requirement is even more important for reliability investments (see section 5.2 below).

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[5] Ministry of Economic Development, *Draft Transport Rules (Part F of the Electricity Governance Rules 2003), Consultation Paper*, 4 November 2003, section 7.1.3.

Issues for consultation

Comments are invited on:

(1) which party or parties should be responsible for investigating, developing and funding transmission alternatives assessed under the GIT; and

(2) the process for investigating, developing and funding alternatives that prove to be the best option available under the GIT.

4.3 BENEFITS AND COSTS

Figure 3 below outlines the effects that should be quantified as benefits and costs in an evaluation of an economic investment under the GIT. These effects may take the form of benefits or costs depending on the circumstances, and only give rise to benefits or costs *when compared to the base case*. Benefits and costs can be one-off or ongoing and need to be discounted (see Section 6.1 below).

There are instances when benefits and costs cannot easily be quantified. They may nevertheless be important in assisting the Board in deciding whether or not to approve an investment, particularly when the cost-benefit analysis does not identify a clear 'winning' project. To the extent that the benefits and costs of a grid investment are difficult to quantify, the direction of the effect and estimates of the likely magnitude should be identified. These estimates can assist in judging the overall merit of the project.

Both the sample grid economic test in Annex 2 of the Ministry's consultation paper and the ACCC's regulatory test provide useful guidance on the specific types of benefits and costs that should be included in the test. The list of benefits and costs should be inclusive, so that other previously unforeseen factors that add or detract from the total surplus could be considered. At the same time, care must be taken to only include benefits and costs that conform to the objectives of the GIT.

Figure 3: Proposed list of quantifiable benefits and costs

Effect	Project benefit	Project cost
Fuel costs	Savings in fuel costs caused by changes in dispatch patterns and the use of cheaper plant (e.g. fuel cost savings arising from the replacement of thermal generation by hydro-electric generation)	Increases in fuel costs caused by changes in dispatch patterns
Capital expenditure	Avoided or deferred capital expenditure on generation and network assets, assuming demand does not change (e.g. reduced network constraints and losses may imply that new generation investment can be deferred by a number of years)	Advancement of capital expenditure on generation and network assets elsewhere in the network, assuming demand does not change. Construction costs of the relevant infrastructure and associated costs of augmentations to the existing network
O&M costs	Avoided O&M costs elsewhere in the network	O&M costs of the relevant infrastructure, including dismantling costs, as well as additional O&M costs elsewhere in the network
Voluntary and involuntary load curtailment	Reductions in voluntary and involuntary load curtailment (e.g. reductions in expected unserved energy)	Increases in voluntary and involuntary load curtailment
Ancillary services	Reductions in ancillary services costs	Increases in ancillary services costs
Transmission losses	Reductions in transmission losses	Increases in transmission losses
Government policies	Subsidy or other direct benefits to the electricity sector arising from Government policies	Taxes or other direct cost to the electricity sector arising from Government policies

Government policies and environmental benefits

Taxes and subsidies are not normally taken into account in a cost-benefit analysis. This is because, unless they reflect 'spillovers' or externalities, they generally represent wealth transfers rather than welfare gains.

The GIT objectives in Part F confirm that only benefits and costs in the electricity sector should be relevant to whether an investment goes ahead under the test (clauses 6.3.1 and 6.3.4, Section III). This means that Government policies on environmental, health and safety and other externalities should be recognised in the test to the extent that they are explicitly priced in the goods and services sold or purchased by parties in the electricity sector. Therefore, for example, a carbon tax should be counted as a cost of thermal generation and a renewables subsidy should be counted as a benefit to wind power plant.

Policies that do not explicitly impose costs or benefits on electricity market parties should be excluded from the analysis, as such policies – while they may be in the interests of society as a whole – do not financially affect parties in the electricity sector. This may change in the future, but until it does, such policies should not be included in the GIT.

Issues for consultation

Comments are invited on the following issues in relation to the types of costs and benefits to be considered:

(1) Whether the costs and benefits listed in Figure 3 are appropriate.

(2) Whether other costs and benefits should be considered and if so, the identity of those other costs and benefits.

5 Reliability investments

Analysing reliability investments under the GIT raises somewhat different questions than an assessment of economic investments. This is because, depending on the nature of reliability standards in place, cost-benefit analysis may not be appropriate for assessing investments designed to maintain those standards.

5.1 RELIABILITY STANDARDS

Grid reliability standards are generally aimed towards ensuring continued and uninterrupted power supplies to consumers. Part F requires the Board to determine and publish grid reliability standards. These standards must be consistent with the system operating standards articulated in Part C. However, the development of reliability standards is a detailed process that is outside the scope of this Discussion Paper. What is important for present purposes is that the GIT can apply to investments directed towards maintaining grid reliability standards, whatever the nature of those standards.

5.1.1 Deterministic reliability standards

Deterministic standards relate to technical or engineering criteria and are the most common approach to specifying reliability standards around the world. For example, deterministic standards may be based on levels of network redundancy, such as an N-1 criterion (provision for a single 'critical contingency'), or voltage or stability requirements. In such cases, breach of a technical requirement acts as a 'trigger' for investment. For example, once an N-1 criterion is breached in a part of the network, grid investment is required to restore the required standard.

5.1.2 Probabilistic reliability standards

The alternative to deterministic standards is a 'probabilistic' reliability standard. Probabilistic reliability standards take account of the probability of contingencies occurring, as well as the cost consequences of those contingencies. They provide a mechanism for explicitly valuing improvements in reliability by placing a dollar value on the expected cost of supply interruptions, or 'unserved energy', due to a fault or an outage. On this basis it is possible to achieve a valuation of reliability benefits that can be compared with the corresponding costs of the reliability investment.

A probabilistic approach therefore requires additional data on:

- the MWh of unserved energy arising from a specified contingency event (say, a transformer outage);
- information about the probability of these events occurring; and
- the estimated dollar cost of the unserved energy, which is derived by multiplying the expected quantity of unserved energy with its estimated value.

5.1.3 Comparison of types of standards

Probabilistic and deterministic planning criteria do not necessarily deliver the same outcomes – deterministic standards, in practice, tend to result in more conservative (more reliable) outcomes and, thus, more expensive grid.

The probabilistic approach to developing reliability standards is more sophisticated than a deterministic approach. In principle, if a probabilistic approach is applied correctly with good quality data, it should result in economically superior outcomes. However, development of probabilistic standards requires more complex models and more detailed data than does development of deterministic standards.

The Ministry has indicated that consideration should be given to the development of probabilistic reliability criteria in the future.[6] The Board is commencing this process. However, at least until this process is complete, the GIT should be capable of assessing reliability investments regardless of the type of standards that are in place.

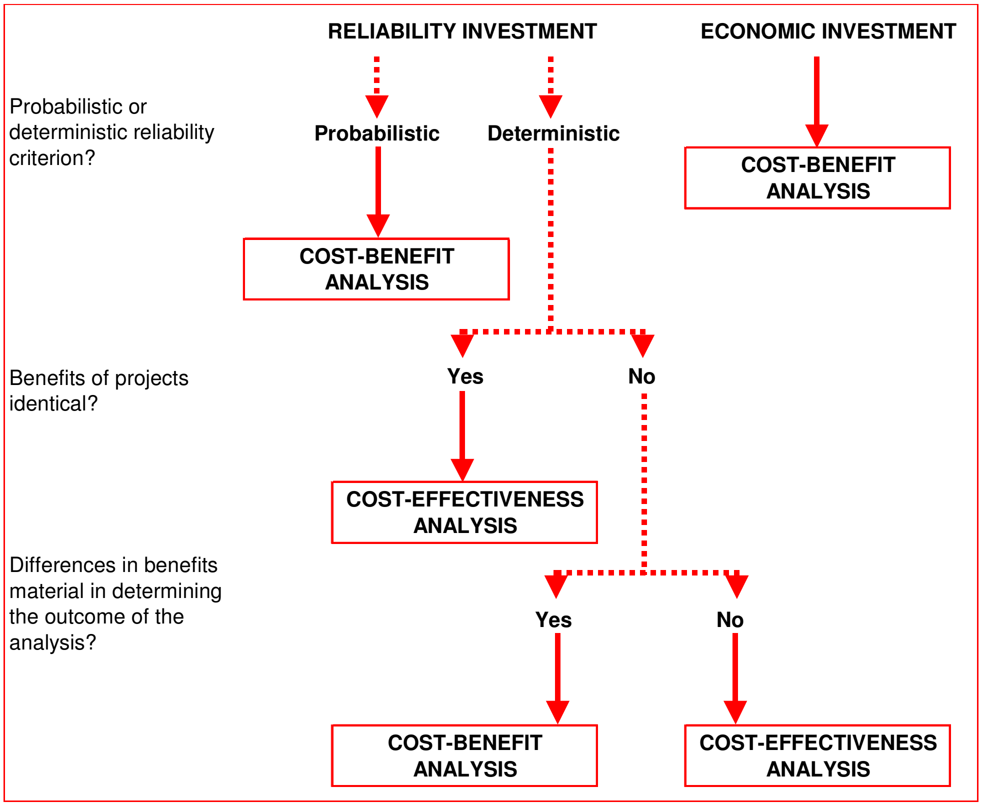
5.2 EVALUATION OF RELIABILITY INVESTMENTS

If unserved energy is explicitly valued, reliability investments triggered by a probabilistic criterion can be assessed in a similar manner as economic investments – by applying a cost-benefit analysis. In this case, the cost-benefit analysis would compare the estimated benefit of avoiding (or minimising) an interruption with the cost of investing to eliminate (or reduce) the risk of the interruption. Therefore, as they are analytically identical, for the remainder of this paper, investments proposed to address probabilistic reliability standards will therefore be referred to as 'economic investments'.

Reliability investments based on a deterministic standard may not be suited to a full cost-benefit analysis, because the benefits of maintaining the criterion are not explicitly valued. The alternative is to undertake a cost-effectiveness analysis. However, cost-effectiveness analysis assumes that different projects have identical benefits, which is not always the case. This highlights that the type of analysis applied to reliability investments should focus on the nature of the project (Figure 4).

6 Ministry of Economic Development, *Consultation Paper, Draft Transport Rules (Part F of the Electricity Governance Rules 2003)*, 4 November 2003, section 7.1.2.

Figure 4: Type of investment and form of analysis



Importantly, for the purpose of assessing reliability investments directed at maintaining deterministic reliability standards, alternative projects should have an identified proponent, so that they are virtually certain to proceed in the absence of the proposed transmission option.

5.2.1 Cost-effectiveness analysis

A cost-effectiveness analysis determines the least-cost solution (out of a range of transmission and non-transmission options) for satisfying a particular technical requirement. In other words, only the costs of a transmission or non-transmission option are taken into account and compared, but none of the benefits. This is appropriate where the projects to be compared produce identical or very similar benefits or where the differences in benefits are unlikely to be material in changing the ranking of investment options.

The advantage of taking such a narrow assessment approach is that it greatly simplifies the application of the GIT to reliability investments.

To ensure that cost-effectiveness analysis is not used to promote expensive transmission projects where other projects may provide greater benefits, it would be appropriate for a cap to apply to the cost of reliability investments that can be assessed using cost-effectiveness analysis. The proposed cap is $10 million.

5.2.2 Cost-benefit analysis

In some instances, reliability investments directed at satisfying deterministic criteria may differ significantly in the level of reliability or other benefits they may provide. For example, a reliability investment directed at meeting an N-1 standard in Auckland may lead to deferral of new embedded generation in the Auckland area. In this case it would be necessary to establish whether or not these additional benefits are likely to be sufficiently large to potentially change the ranking of investment options.

If a reliability investment or its alternatives are expected to deliver significantly different and material non-reliability benefits, it is more appropriate for the options to be assessed using a cost-benefit analysis. Differences in expected unserved energy for these projects then need to be assessed in broad terms, priced at (different) estimates of the value of unserved energy and fed into the analysis. Differences in costs of constraints and in plant deferral must also be included. The best project out of all the alternatives may still not have positive net market benefits, in which case the project that minimises the net market cost of meeting the standard meets the requirements of the test.

5.2.3 Summary

A cost-benefit analysis approach is appropriate for a project directed towards satisfying deterministic reliability criteria if the project and its alternatives deliver significantly different benefits that may change the eventual ranking of project options and if the investment is relatively high-cost.

Issues for consultation

Comments are invited on the following issues in relation to the types of costs and benefits to be considered:

(1) Whether cost-effectiveness is appropriate for reliability investments where the project and its alternatives are expected to have identical or near identical benefits or differences in benefits are unlikely to be material in changing the ranking of investment options.

(2) Whether a cap of $10 million or another value should apply to the use of cost-effectiveness analysis for reliability investments.

6 Cost-benefit modelling parameters

The GIT needs to clarify a number of modelling parameters for investments (economic or reliability) that undergo cost-benefit or cost-effectiveness analysis. The key modelling variables are:

- the discount rate;
- the timeframe;
- assumptions about the value of unserved energy;
- the nature and valuation of competition benefits; and
- explicitly taking account of uncertainty.

6.1 DISCOUNT RATE

The discount rate under the GIT is used to convert future cash flows to net present values (NPVs). The choice of discount rate potentially affects the outcomes of the GIT:

- by determining whether the NPV of a project is positive or negative in the first place; and
- by potentially changing the ranking of projects, but only if the pattern of cash flows is sufficiently dissimilar across projects.

Discount rates are applied to expected cashflows in cost-benefit analysis on the basis that a dollar today is preferred to a dollar tomorrow, even leaving aside expectations of inflation. However, identifying the precise discount rate that should be used in cost-benefit analysis has been a controversial subject in both the academic and applied literature. Therefore, while this section outlines some of the key issues, preference has been given to a pragmatic approach.

There are two key issues involved in determining an appropriate discount rate:

- the discount rate that should apply to a project in a riskless world; and
- whether and how the discount rate should be adjusted to reflect the riskiness of a project's future cashflows.

6.1.1 Discount rate in a riskless world

In the absence of risk, the discount rate should reflect the extent to which the decision-maker prefers a certain return today compared to a certain return in the future.

Determining the extent of the preference for current benefits over future benefits raises the issue of what form the benefits and costs of a project take. Investing in a project involves the sacrifice of present resources that would otherwise be used for some combination of consumption, investment or foreign debt reduction (other things being equal).[7] Thus the costs of an investment may be thought of as an 'opportunity cost' – that is, the opportunity foregone to either consume, invest in an alternative project, or reduce foreign debt.

If the analysis in question is a decision where the relevant costs and benefits of a project primarily affect private consumption, then the appropriate discount rate is the social time preference rate (STPR). The STPR is the rate that the decision-maker compares private consumption today with private consumption in the future. Depending on the timeframe for the project, it can involve complex moral judgements about the welfare of different generations.

As the Part F objectives for the GIT require consideration of alternatives before a transmission project satisfies the test, it seems likely that in most cases, a regulated transmission project will have the primary impact of displacing private electricity investment. In this context, the appropriate discount rate is the marginal *social* rate of return on private investment. As this is unobservable, in practice, this is often approximated by the *private* rate of return on investment.[8]

It should be noted that the use of a private rate of return will typically not change project rankings. As noted by Mishan in his seminal text on cost-benefit analysis:

> '… the use of a market rate of return on private investment, rather than the social rate…, though it will of course affect the magnitudes of the terminal (or present) values, *is not very likely to make any difference to the resultant ranking of the public projects*…the alternative investment profiles would have to be *markedly different*, and the divergence between the ideal [social rate of return] and the market rate of return on private investment would have to be *quite startling*, for the use of the market rate of return to generate a different ranking of public projects than that which would result from the use of [a social rate of return].'[9] [emphasis added]

6.1.2 Treatment of uncertainty

Whether and how uncertainty should be incorporated into the discount rate is at least as controversial as the determination of the risk-free discount rate. There are at least two different ways of looking at this problem.

Cost of capital approach

Modern financial theory holds that the discount rate applied to a risky project (the cost of capital) should reflect the systematic (non-diversifiable) risk of the project. One important implication of this approach is that the cost of capital is independent of the cost of financing the project.

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7 Bureau of Transport Economics, *Facts and furphies in benefit-cost analysis: transport*, Report 100, 1999, (BTE) pages 61-62.

8 BTE, page 65.

9 Mishan, E.J., *Cost-Benefit Analysis*, 1976, Praeger Special Studies, New York (Mishan), page 253.

Under this approach, the discount rate would be the private discount rate applying to an investor in electricity transmission assets. This is likely to be higher than the regulatory weighted average cost of capital (WACC) applicable to Transpower, which may not reflect the risks of transmission investment to customers.

Separation of uncertainty approach

The key alternative to a cost of capital approach is to separate issues of uncertainty from the discount rate.[10] According to this view, raising the discount rate to allow for uncertainty is the wrong approach as it arbitrarily favours projects with benefits that grow slowly after a good start compared with projects with benefits that grow strongly after a poor start. Instead, a risk-free discount rate should be applied and uncertainty should be accounted for by considering how project cashflows would be affected by different events.

Discussion

The differences between the two outlined approaches appear to be in the way that uncertainty is handled – through statistical means (cost of capital) or by adjusting cashflows directly in anticipation of different events (separation). Both approaches are consistent in acknowledging that uncertainty over project variables is important in determining whether or not to undertake a particular project.

The discussion on uncertainty in Section 6.4 below recommends that a scenario-based approach be used to account for uncertainty in favour of a more complicated real options approach. However, without detailed information on all the events that could affect a project's cashflows, the assessment of uncertainty using a separation approach will be incomplete and the negative impact of uncertainty will be understated.

As a substitute for an analysis of all possible events that could affect a project's cashflows, it may be reasonable to use a hybrid approach, which considers a relatively small number of cashflow-affecting events combined with a discount rate based on risky private investments as per the cost of capital approach. This has two key advantages:

- it promotes regulated transmission investment decision-making on a similar basis as transmission alternatives are likely to be assessed. This helps ensure that regulated projects are not systematically favoured over unregulated projects; and
- it allows some consideration of uncertain project variables but without placing excessive pressure on the GIT assessor to foresee and place a probability on every possible event that could affect project cashflows.

For the sake of simplicity and competitive neutrality, the GIT should apply a single, private rate of return for investments in the electricity sector.

10 See BTE, pages 73-78.

Transpower's WACC is unlikely to be suitable for this purpose as it may not reflect the risk of investment in transmission to all relevant parties.

By way of comparison, the Australian regulatory test is also based on a private discount rate. In Australia, recent central discount rates (pre-tax real) that have been applied under the regulatory test have been 8-9%, with sensitivities between 6 and 11%.

Issues for consultation

Comments are invited on:

(1) Whether the appropriate discount rate to be applied under the GIT should be a rate that would be applied by a private investor in the electricity sector.

(2) In light of (1), what the discount rate should apply.

6.2 TIMEFRAME

The GIT analysis of costs and benefits takes place over a certain timeframe. As time passes, expected cashflows are likely to become less certain and more difficult to predict. While this can be accommodated through consideration of uncertainty (see Section 6.4 below – for example, by development of a range of scenarios or real option values), there comes a point at which considering a longer timeframe imposes more analytical costs than likely benefits.

For example, the majority of the costs and benefits of electricity related investments will be incurred and emerge in the first 20 years of a project. Beyond this time scale, the relative magnitudes of costs and benefits generally stabilises and, together with the impact of discounting, considering longer periods is unlikely to alter the conclusions.

Therefore, in the interests of striking a balance between comprehensiveness and making the GIT tractable, a timeframe of 20 years is proposed. If significant benefits or costs are expected to arise after that time, they could be accommodated through the addition of a 'terminal value' – the expected then-present value of the costs or benefits of the project.

Issues for consultation

Comments are invited on whether a 20 year time horizon is appropriate for the consideration of the costs and benefits of projects.

6.3 COST OF UNSERVED ENERGY

The GIT must include a value or a reference to the opportunity cost of unserved energy to customers – the value that customers place on avoiding interruptions of supply. The value that is placed on unserved energy plays a central role in this analysis in two respects.

First, unless a simplified cost-effectiveness approach is applied, reductions in unserved energy arising from a proposed augmentation need to be valued. This is particularly the case where probabilistic reliability standards are applied and reliability is valued explicitly as an economic benefit. However, even where deterministic standards are in place, it may be that different reliability options that meet the same standard (e.g. N-1) lead to different expected quantities of unserved energy. If these quantities could be reasonably estimated and a cost-benefit approach is used to compare these options, the value of avoiding unserved energy would need to be determined. Finally, an economic investment not directed towards maintaining reliability may also reduce the quantity of unserved energy, which would need to be valued.

Second, the value of unserved energy will drive the timing of modelled projects in the market development scenarios. For example, if modelled projects are introduced into the market on the basis of a least-cost expansion plan, a higher value of unserved energy will result in earlier entry of plant, other things being equal.

In summary, the value given to unserved energy is crucial in determining the level of transmission investment.

6.3.1 Valuations of unserved energy

New Zealand

The NZEM does not explicitly place a value on unserved energy by posting a VoLL price cap. Transpower's current deterministic grid reliability standards also do not easily map onto a particular value of unserved energy.

However, the GPS recently outlined an objective to ensure security of supply in a 1 in 60 dry year, without assuming any demand reduction from emergency conservation campaigns, while minimising distortions to the normal operation of the electricity market. According to the Morrison report for the Government, given the marginal cost of reserve plant (about 15-20c/kWh), such a standard implies a *minimum* value of electricity of $9-12/kWh ($9,000-12,000/MWh).[11]

While the 1 in 60 year criterion clearly indicates the Government's dry year security objectives, the use of this figure to generate a valuation of unserved energy for transmission planning may be inappropriate. Moving from the 1 in 60 year criterion to a valuation of unserved energy by multiplying the cost of reserve plant by 60 is based on the notion that where the probability of supply shortfalls is less than 1/60th (1.67% of the time, or 6 days per annum), it is appropriate for emergency conservation campaigns to operate rather than reserve generation.

11 Morrison & Co, *Issues concerning the reserve generation proposal*, 12 August 2003, Appendix D, pages 89-92

This may represent an under-estimation of customers' shorter-term valuation of electricity. As the GPS notes in discussing conservation campaigns:

> *"In* [a greater than 1 in 60 dry year] *the Government expects the Commission to activate an effective conservation campaign in a timely manner, since conservation is significantly less damaging to the economy and disruptive to consumers and public welfare than actual blackouts."* (para 60)

This suggests that a valuation of unserved energy for transmission planning purposes – where sudden and unexpected supply disruptions may follow from critical contingencies – should be at least $10/kWh ($10,000/MWh) and possibly significantly higher.

Little work in New Zealand has been done recently on calculating valuations of unserved energy. Appendix D of the Morrison report referred to the FSWG report to the GSC, which examined the cost of non-supply (CNS).[12] The FSWG report concerned the proposal to raise the minimum level of frequency allowed during a double contingency.

The FSWG report used CNS values of $5-10/kWh for residential consumers and $30-80/kWh for non-residential consumers.[13] However, the FSWG did not itself undertake any research on CNS. The report noted that the most recent study in New Zealand was the Centre for Advanced Engineering (CAE) study "Reliability of Electricity Supply Project" carried out in 1992. The CAE study was not specifically designed to measure CNS, but arrived at values of:

- $1.5-5/kWh ($1,500-5,000/MWh) for residential consumers; and
- $10-70/kWh ($10,000-70,000/MWh) for non-residential consumers,

all in 1992 dollars.[14]The FSWG report then examined research from overseas.

International

In the absence of recent New Zealand research, it may be appropriate to look overseas for guidance on an appropriate valuation of unserved energy. The key drawback of this approach is that international decisions may not be appropriate to New Zealand conditions, particularly in an area (setting the value of unserved energy) that is very sensitive to political and value judgements.

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12 FSWG report to the GSC – Appendix 6 – *Analysis of Immediate Solution* (FSWG), Page 18.

13 FSWG, Annex A

14 FSWG, Annex A, page 1.

With this caveat in mind, VENCorp in Victoria, Australia, has commissioned extensive research on customer values of reliability (VCR) and in 2002 developed the following indicative ($A) values:

- residential customers: $39,400/MWh;
- commercial customers: $184,600/MWh;
- agricultural customers: $12,600/MWh;
- industrial customers: $59,300/MWh; and
- a weighted average value of $29,600/MWh.[15]

The VoLL price cap in the Australian NEM is presently $A10,000/MWh. The ACCC's recent revised regulatory test draft decision stated that both VCR and VoLL values should be used as sensitivities.

Other recent estimates of values for unserved energy have been:

- Monash University Centre for Electrical Power Engineering:
  - for Victorian Power Exchange, Victoria, Australia (August 1997) – residential $A0.74/kWh, commercial $A75.96/kWh, agricultural $A96.2/kWh, industrial $A11.19/kWh and weighted average $A28.89/kWh[16];
  - for TransGrid, New South Wales, Australia (July 1998) – residential $A0.49/kWh, commercial $A52.37/kWh, agricultural $A57.59/kWh, industrial $A20.46/kWh and weighted average $A20.56/kWh[17];
- Kariuki and Allan, for Manweb, MED and NORWEB, Britain (1996) – $US18,500/MWh[18]; and
- CEC, California, USA (June 1997) – no composite value but separate values for residential ($US1.3/kWh), commercial ($US37.2/kWh) and industrial and other ($US24.4/kWh)[19].

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15 CRA, *Assessment of the Value of Customer Reliability (VCR), December 2002*, pages 6 and 42.

16 Centre for Electrical Power Engineering, *Draft Report on Consultancy, Value of Lost Load Study for Victorian Power Exchange*, August 1997, page 20. (NB Although this report is entitled "Draft", it is actually the Final Report.)

17 Centre for Electrical Power Engineering, *Report on Consultancy, Value of Lost Load Study for Transgrid*, August 1997, page 21.

18 Kariuki, K and R Allan, *Evaluation of Reliability Worth and Value of Lost Load*, IEE Proceedings – Generation, Transmission and Distribution, (1996) Volume 143, Issue 6, pages 521-528, as described in Cramton, P and J Lien, *Value of Lost Load*, University of Maryland, 14 February 2000, page 3.

19 CEC, *Survey of the Implications to California of the August 10, 1996 Western States Power Outage* (June 1997).

6.3.2 Discussion

In light of the FSWG report and the international surveys, a value of \$10,000/MWh would appear to be reasonable for residential consumers but too low for non-residential consumers. At the same time, it would be difficult to support a composite value above \$30,000/MWh given that this is already many times most residential valuations, and residential consumers often make up close to half of total load.

Given the difficulties with using international benchmarks, further work could be considered to develop a more sophisticated valuation of unserved energy. In this regard, it may be appropriate to develop several measures for different types of customers and locations and different durations of unserved energy. The Board is likely to be best placed to oversight this work program. In the interim, historic local and international benchmarks may be applied cautiously and with a focus on applying a range of values to test the sensitivity of the conclusions and project rankings to variations in this key parameter.

In this context, Frontier proposes that an initial central value of unserved energy of \$20,000/MWh be applied, with sensitivities of \$10,000/MWh and \$30,000/MWh to be used where the size and cost magnitude of the project warrant the additional analysis.

Issues for consultation

Comments are invited on whether a grid test assessment should be based on an initial central value of unserved energy of \$20,000/MWh with sensitivities of \$10,000/MWh and \$30,000/MWh to be used where the size and cost magnitude of the project warrant the additional analysis.

6.4 UNCERTAINTY

A key issue for the GIT is how uncertainty is treated. For example, load may grow at different rates in future, which in turn could affect the net benefits of developing an augmentation or its alternatives.

As discussed above in relation to the discount rate, there are a number of ways to handle uncertainty, some of which affect the choice of discount rate. As a generalisation, to the extent that uncertainty is accounted for in the choice of discount rate (i.e. through a cost of capital approach), less attention should be given to considering project uncertainty separately. Hence there is some interdependence between the discount rate chosen and the required complexity of uncertainty analysis.

The recommended discount rate for the GIT is based on the required return of a private investor in the electricity sector. This suggests that while uncertainty still needs to be considered under the GIT, an exhaustive analysis is not required. The discussion below proceeds on this basis.

6.4.1 Scenario analysis

Scenario or sensitivity analysis focuses on the critical elements on which the beneficial outcome of a project depends. It accounts for uncertainty by changing a key variable and assessing the implications for a project's net benefits and ranking.[20] Sensitivity analysis can be undertaken flexibly for individual variables and combinations of variables and is also not highly complex to implement if attention is restricted to a small number of key variables, as is proposed.

Using scenario analysis, the GIT could require that an investment will only pass the test, if it maximises the net benefits (or minimises the costs) in the greatest proportion of reasonable scenarios. The proposed requirement to consider reasonable scenarios should allow Transpower and the Board the flexibility to concentrate on scenarios with the highest probabilities.

6.4.2 Real options theory

An alternative approach to dealing with uncertainty is based on 'real option theory'. This theory was developed pursuant to approaches to financial option pricing and focuses on the benefits and costs of investment flexibility. The key features of real options analysis are briefly described in Annex 4. However, the key implications of adopting a real options approach would be that:

- all relevant options (areas of flexibility) would need to be assessed; and
- the benefits and costs of all options would need to be quantified.

Given the unusual characteristics of electricity markets, it would be difficult, if not impossible to accurately value the most important real options for transmission and non-transmission projects. In practice, the GIT must be robust and workable, and a real options approach would add significant complexity to the test for little additional benefit. Moreover, as discussed in Annex 4, approximate real option values are effectively considered in any case by a sensitivity/scenario-based approach to uncertainty.

Issues for consultation

Comments are invited on whether the GIT should utilise sensitivity/scenario analysis to account for uncertainty in project cash flows. An investment should meet the requirements of the test if it maximises net benefits (or minimises costs) in the greatest proportion of reasonable scenarios.

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20 For the sake of clarity, 'sensitivity' refers to changes to input variables, while 'scenario' refers to changes to the base case and project case resulting from a sensitivity. For example, the use of a different discount rate is a 'sensitivity' but the base case (and project case) with a changed interest rate is a 'scenario'.

6.4.3 Key variables

A further question relates to which input variables should be varied to take account of uncertain assumptions. Again, practical considerations will play a role. Large numbers of scenarios and sensitivities tend to add significant complexity to modelling analysis, and increase the scope for errors and subjective judgement. Rather than concentrating on a broad array of factors, it is likely to be preferable to identify a limited number of central key factors that will impact on a project's benefits and costs and fully investigating these.

The key variables that should be considered (although not necessarily applied) for undertaking sensitivity or scenario analysis include varying:

- peak and average demand forecasts;
- weather patterns or hydrological scenarios, such as 'dry year' and 'wet year' implications for hydro generation and required plant build;
- values of unserved energy to consumers;
- capital and operating costs of new generating plant;
- expected commissioning dates of transmission augmentations, alternative projects (such as generation and DSM options), committed projects, anticipated projects and modelled projects;
- the discount rate used; and
- market development scenarios: scenarios based on non-competitive bidding.

Issues for consultation

Comments are invited on whether there are any other variables that should be considered when accounting for uncertainty in the cost-benefit analysis.

6.5 COMPETITION BENEFITS

'Competition benefits' potentially arise from a transmission augmentation if the augmentation reduces generator market power and thus reduces average wholesale prices.[21] These price reductions can lead to market benefits in three key ways:

- lower cost dispatch;
- higher demand and a larger market; and
- deferral of new generation plant.

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21 Annex 2 describes the nature of competition benefits in more detail.

6.5.1 Enhanced competition in the wholesale market

The discussion about the principles of cost-benefit analysis highlighted that the GIT focuses on the *combined* net increase in consumer and producer surplus created by an investment, but not on how these benefits are distributed between consumers and producers. This has implications for whether and how the benefits of greater competition in the wholesale market should be considered.

Short-term perspective

Assuming demand is extremely unresponsive to price – as it generally is in electricity markets in the short term – a reduction of generator market power leading to lower prices will generally lead to a higher consumer surplus at the expense of producer surplus, but may not increase the size of the combined surplus. The combined surplus will only increase if the reduction in market power reduces the dispatch cost of supplying load. Therefore, a transmission augmentation that leads to greater competition and lower prices could primarily cause only a wealth transfer from generators to consumers. This may be considered desirable from a point of view of benefiting customers, and some stakeholders may claim that a wealth transfer from generators to consumers is a 'benefit' that should be taken into account under the test. However, it is considered that such an approach would neither conform to standard principles of cost-benefit analysis, nor be consistent with the objectives of the grid test in Part F. This is not to deny that politicians may choose a policy that delivers gains to consumers even it though it does not result in a gain overall, and as elected representatives of the community, they are entitled to make this choice.

Dynamic perspective

In the longer term, electricity demand does respond to changes in prices. Consequently, if an augmentation leads to greater competition and lower wholesale prices, this should stimulate an expansion of demand and an increase in combined consumer and producer surplus. Given that the analysis is predicated on an assessment of costs and benefits over a long period of time, we might expect that these responses to price changes may produce material 'competition benefits'.[22]

If such competition benefits do arise in the longer term then, in principle, they should be included in the application of the grid test. However, modelling competition benefits of an augmentation is not straightforward because it:

- requires the ability to accurately and predictably model how participants with market power bid, both before and after the augmentation; and
- also involves modelling the competition benefits of any alternative projects, in order that the *total* net benefits of all options (including competition benefits) can be compared.

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22 Annex 2 provides a diagrammatic explanation of how this increase arises.

In practice, the ability to model these potential benefits and to meet the test's requirements for clear, robust and reliable estimates does present a significant challenge. These difficulties do not mean that competition benefits should be excluded, but that the modelling approach used needs to be robust and transparent to cater for the additional level of uncertainty that attaches to such estimates.

6.5.2 Plant deferral

A key purpose of the wholesale market arrangements is, among other things, to signal the need for new plant through prices. In particular, high prices are meant to provide signals for investment. If these high prices are the result of the exercise of market power and this results in earlier generation investment than would be the case in a more competitive market, transmission investment that increases competition may result in lower costs of supply.

Incumbent generators with market power could be expected to entrench their positions by creating entry barriers for new generators. One of the most effective entry barriers in an industry involving large fixed costs is sunk costs. Incumbent generators can create this barrier by investing in new generation ahead of when it is optimal (from a cost-minimisation perspective). To the extent transmission augmentation enhances competition and the incentive and ability to engage in this type of activity is reduced, this could lead to an increase in economic welfare.

Here, as for the discussion above, modelling wholesale price levels for different 'degrees' of generator market power is an uncertain exercise. Both in theory and in practice, many bidding 'equilibria' can be identified, each corresponding to different wholesale price levels at different times. Game theoretical modelling is a means of identifying such equilibria, but even if such a theoretically robust approach is applied, considerable scope for subjectivity remains.

6.5.3 Treatment of competition benefits

Competition benefits raise modelling difficulties, but this does not imply that such benefits should be *excluded* from assessment of projects under the GIT. The best approach may be to recognise that competition benefits can arise, but allow the investment proponent to include such benefits if they are considered material and subject to a clear description of its methodology.

The ACCC's recent draft revised regulatory test proposed that the calculation of market benefit *may* include competition benefits, effectively leaving it up to the investment proponent to decide whether or not competition benefits were worth including. However, because of the additional level of modelling complexity and uncertainty required to model competition benefits – requiring information on demand elasticities and predictions of non-competitive bidding – it may be appropriate to place competition benefits in a separate 'pool' from other benefits so that a judgement can be made on its magnitude and importance. It may also be reasonable to require sensitivities to be carried out for important inputs into the determination of competition benefits, in particular assumed wholesale price reductions.

Issues for consultation

Comments are invited on whether competition benefits should be included in the GIT, and if so, how they should be measured.

7 Practical interaction with Part F

This section discusses the practical interaction of the GIT with the other requirements set out in Part F.

7.1 DATA SOURCES

The proposed draft GIT draws on a variety of data from different sources. Part F explicitly provides for two key documents to be published by the Board to assist in the identification and evaluation of transmission and non-transmission alternatives by private investors:

- The purpose of the Statement of Opportunities (SOO) is to 'enable identification of potential opportunities for efficient management of the grid including investment in upgrades and investment in transmission alternatives' (clause 9, section III). The SOO should aim to meet the needs of Transpower, private investors and other stakeholders by including information on grid reliability standards, grid planning assumptions that cover a reasonable range of credible scenarios, and analysis of the power system with respect to those variables.
- Part F requires the Board to establish, maintain and publish a centralised data set on network capabilities, performance and constraints.

Proponents of non-transmission projects should have accurate information on their own costs and should be able to obtain reasonable estimates of other generators' costs. Transpower and the Board should also be able to obtain this information from participants and other sources. In combination, this information should support efficient investment decisions and facilitate Transpower's application of the GIT.

7.2 DEVELOPMENT OF RELIABILITY STANDARDS

Part F requires the GIT to provide information for the development of grid reliability standards, as well as decision criteria for the approval of a reliability investment. This could be achieved through a staged approach.

In the immediate future, the GIT could be used to compare the costs of ensuring different deterministic standards, such as N, N-1 and N-2 in various locations. Any investments that satisfied a given standard at least cost or at a greater net benefit (depending on the form of analysis chosen) would 'meet the requirements of the GIT' for the purposes of clause 13.4.1.3 of Section III of Part F. In other words, a number of reliability investments may satisfy the test, but at different standards.

In giving its approval to a specific reliability investment, the Board would need to make a trade-off between different deterministic standards and the costs of the investments required to satisfy those slightly differing standards. This approach would ensure the test would provide both a decision criterion for reliability investments, albeit a relatively weak one, as well as assisting the Board to develop appropriate reliability standards.

Over time, better data on equipment and line probabilities of failure could enable the Board to assess:

- what constitutes an appropriate valuation of unserved energy in different parts of Transpower's network;
- what the implications are of alternative valuations of unserved energy for longer-term grid investment and corresponding costs; and
- correspondingly, the eventual form that a probabilistic reliability criterion could take.

7.3 MATERIALITY THRESHOLD

The GIT need not apply to every item of capital expenditure by Transpower. The analysis required to apply the GIT is potentially substantial, and the Australian experience has highlighted the potentially high costs of associated consultation and dispute resolution processes.[23] Some threshold is therefore required that balances the costs of conducting the test with the likely efficiency benefits that could be gained from a detailed analysis.

The two key choices for a materiality threshold are:

- a fixed dollar figure based on a view of what is a 'significant' transmission investment; and
- a decision based on the nature of the investment or the nature of the alternatives available or considered. For example, if a proposed grid augmentation has no clear alternatives, application of the GIT could involve consideration of 'notional' – in effect artificial – alternatives and hence not be worthwhile.

The problem with the second approach is that it involves a judgement by Transpower or possibly the Board on an augmentation's alternatives prior to a formal transparent assessment of the alternatives. The first approach, though somewhat arbitrary, is therefore preferable.

We understand that the typical costs of a transformer would be in the order of $1.5 million, and replacement of two transformers in a substation would cost in the order of $3 million. Consideration of other relatively common works, such as line realignments, would suggest a higher materiality threshold, perhaps $5 million, remembering that relatively simple cost-effectiveness analysis could be conducted for reliability investments up to a value of $10 million.

In light of the above information, we consider that an initial minimum dollar materiality threshold of $5 million may be appropriate.

23 Although it is acknowledged that the arrangements in New Zealand will not be as open to litigation as they are in Australia.

Issues for consultation

Comments are invited in relation to the following materiality threshold issues:

(1) Whether an absolute dollar approach should be used for setting the materiality threshold for application of the GIT.

(2) Whether the proposed threshold figure of $5 million is appropriate.

7.4 INTERACTION BETWEEN THE GIT AND INVESTMENT CONTRACTS

An important issue raised in the course of the Government's consultation on Part F of the Rules was the interaction between the GIT and investment contracts (i.e. non-regulated agreements for transmission investment). Part F clearly provides for investment contracts to facilitate certain transmission investments where the relevant investor finds it worthwhile and implications for grid reliability standards are addressed (clause 8, Section III).

Frontier's Issues Paper on the proposed guidelines for the transmission pricing methodology addresses the question of how the costs of regulated assets should be recovered, and the scope for allocating investment costs in shared transmission networks. However, this leaves a remaining question in relation to investments that have failed the GIT. That is, should the proponent of a project that has failed the GIT be permitted to contribute the funds required for the project to 'pass' the test.

The GIT is concerned with identifying investments that maximise net benefits to the electricity sector as a whole. Distributional impacts – ie. who wins and who loses from a particular investment – are ignored. If, in the normal course of events, a participant is willing to contribute towards an augmentation under contract, this suggests that they are a 'winner' from the augmentation. But any contribution from a 'winner' does not diminish the costs of the augmentation to society, nor does it change the fact that the investment is not net beneficial from a wider perspective.

On the other hand, it is possible to conceive of cases where a party is willing to partly fund an augmentation without expecting to recoup corresponding benefits in the case of that particular project. The test should allow scope for the Board to include such contributions in reducing the net costs of the project.

An investment contract should therefore generally not affect or otherwise change the outcome of an assessment under the GIT – investments commissioned under contract should remain separate from regulated investment evaluated under the GIT. However, the Board should have discretion to modify this rule in a specific case, if it is shown that the contributing party is likely to not recoup the cost of its contribution.

Issues for consultation

Comments are invited in relation to the following investment contract issues:

(1) Whether the Board should have the discretion to allow proponents to contribute funds (for which they will receive no regulated return) to allow a project to pass the GIT.

(2) If the Board does retain such discretion, whether there should be any restrictions on the level of contribution.

Annex 1: Term Sheet for draft GIT

The following presents a proposed *term sheet* that could be used as a basis for developing the GIT as a comprehensive legal document.

Comment is sought on whether the terms adequate reflect the discussion in the body of the Discussion Paper, and the nature of any additions or changes.

GIT Terms Sheet

1. Purpose

Clause 6 of Section III of the Part F Transport Rules requires the Electricity Governance Board, also known as the Electricity Commission (the Board) to determine a GIT, having regard to the objectives in that clause.

The principal purposes of the GIT are to:

- Establish that proposed transmission investments provide the greatest net benefit or satisfy reliability standards at least cost after taking into account transmission alternatives; and
- Provide information, including efficient locational signals, to proponents of investors in generation, demand-side management, distribution networks and transmission investment contracts.

2. Objectives

The objectives of the GIT are contained in the Part F Transport Rules.

3. Application

The GIT is to be applied to individual grid investments with a cost above the materiality threshold of $5 million.

The timeframe for analysis is 20 years. However, if substantial net benefits or costs are expected beyond this timeframe, a terminal value may be included.

4. Type of investment and form of analysis

Economic investments

A proposed economic investment satisfies this test if it maximises the net market benefit, compared with a number of alternative projects, in the greatest proportion of reasonable scenarios.

Reliability investments

A proposed reliability investment intended to maintain probabilistic reliability standards satisfies this test if it maximises the net market benefit, compared with a number of alternative projects, in the greatest proportion of reasonable scenarios.

A proposed reliability investment intended to maintain a given deterministic reliability standard satisfies this test if:

- it maximises the net market benefit or minimises the net market cost, compared with a number of alternative projects, in the greatest proportion of reasonable scenarios; or
- if the cost of the investment is up to $10 million, it minimises the cost of meeting that standard, compared with a number of alternative projects, in the greatest proportion of reasonable scenarios.

Probabilistic reliability standards are reliability standards that are framed in terms of a target value of unserved energy.

All other reliability standards are deterministic reliability standards.

Unless otherwise stated, the term project refers to transmission and non-transmission projects.

5. Alternative projects

Economic and reliability investments must be compared with a number of alternative projects. Alternative projects selected for comparison must be:

- technically feasible;
- commercially feasible, in that they are likely to proceed in the absence of the proposed transmission project. In the case of an alternative for a reliability investment intended to satisfy deterministic reliability standards, the project must, in addition, have an identified proponent;
- expected to provide similar benefits to the same nodes in a similar timeframe. In the case of a reliability investment, the alternative must satisfy the relevant reliability standard in the same location at a similar time as the proposed transmission investment;
- appropriate in number and technology given the cost magnitude of the proposed transmission investment, the complexity of the required modelling and the urgency of the investment (if it is a reliability investment).

For the sake of clarity, the alternatives selected must include appropriate transmission projects.

6. Net market benefit

Net market benefit means the market benefit of a project less the cost of the project. If the net market benefit of a project is negative, this is referred to as the project's net market cost.

7. Base case

The base case for assessment of a transmission investment and its alternatives must describe and incorporate:

- Current:
  - size and location of customer load;
  - values of unserved energy (initially, $20,000/MWh but to be replaced by a value or values published by the Board);
  - operating and maintenance costs of competitively supplying load from existing projects;
  - transfer capacities and capabilities of key transmission lines; and
  - ancillary services costs and transmission losses involved in competitively supplying load; and
- Expected future market development, including:
  - size, timing and location of load growth;
  - value of unserved energy (initially, $20,000/MWh but to be replaced by a value or values published by the Board);
  - size, location, timing, capital costs and operating and maintenance costs of competitively supplying load from committed, anticipated and modelled projects, including projects intended to maintain reliability standards;
  - transfer capacities and capabilities of key transmission lines; and
  - ancillary services costs and transmission losses involved in competitively supplying load.

8. Market development scenario projects

The criteria for committed and anticipated project are as follows:

- The proponent has obtained all required planning consents, construction approvals and licences, including completion and acceptance of any necessary environmental impact statement;
- Construction of the project must either have commenced or a firm commencement date must be set;
- The proponent has purchased/settled/acquired land (or commenced legal proceedings to acquire land) for construction of the proposed project;
- Contracts for supply and construction of the major components of the plant and equipment (such as generators, turbines, boilers, transmission towers, conductors, terminal station equipment) should be finalised and executed, including any provisions for cancellation payments; and
- The financing arrangements for the project, including any debt plans, must have been conducted and contracts.

Committed projects are those that satisfy all the criteria whereas anticipated projects are those that satisfy all but one of the criteria and are in the process of satisfying the remaining criterion.

Modelled projects are:

- non-transmission projects that are expected to occur within the assessment timeframe on the basis of least-cost market development and any other approach that is an appropriate sensitivity; and
- transmission projects that are expected to occur within the assessment timeframe for the maintenance of grid reliability standards (other than the project and alternatives being assessed).

Least-cost market development involves the introduction of a non-transmission project of a particular size, location and timing on the basis that it is the least-cost non-transmission project for competitively supplying the relevant load.

9. Discount rate

Present value calculations should use a discount rate appropriate for the analysis of a private enterprise investment in the electricity sector. In determining whether to use a real, nominal or pre- or post-tax discount rate, the guiding principle is that the discount rate should be consistent with the cash flows being discounted.

10. Market benefit of the relevant project

The market benefit of a project is the net present benefit of a project (but not including the cost of the project – see 11 below) to those who produce, distribute and consume electricity in the New Zealand electricity market compared with the base case. This includes the present value of the economic impact of the project on the following variables compared with the base case:

- Fuel costs of existing, committed, anticipated and modelled projects;
- Value of voluntary and involuntary load curtailment;
- Timing of capital expenditure on committed, anticipated and modelled projects;
- Size of capital expenditure on committed, anticipated and modelled projects;
- Size of operations and maintenance expenditure on existing, committed, anticipated and modelled projects; and
- Ancillary services costs and transmission losses of competitively supplying load.

Subject to this test, the market benefit of a project may include competition benefits, but these benefits must be calculated and presented separately.

The competition benefits of a project are the increases in market benefit brought about by the impact of greater competition on:

- Generator and demand-side bidding;
- Forecast load growth; and

- Avoidance or deferral of committed, anticipated or modelled projects.

The effect of a project on likely prices is to be modelled by comparing bidding before the project with generator and demand-side bidding after the project using a modelling approach that accounts for the interdependence in bidding behaviour.

Where material benefits and costs of a grid investment cannot be quantified, the direction of the effect and likely magnitude should be identified.

11. Cost of the relevant project

The cost of a project includes the present value of:

- Capital costs incurred prior to the commissioning of the project;
- Operating, maintenance and dismantling costs over the operating life of the project;
- Costs to the New Zealand electricity market associated with project testing;
- Any additional amount, approved by the Board, that could reasonably be considered related to a proposed transmission investment or alternative investment being commissioned;
- Costs of complying with or arising pursuant to all applicable existing and anticipated laws, regulations and administrative determinations; less
- Subsidies or other benefits provided under or arising pursuant to all applicable laws, regulations and administrative determinations.

12. Sensitivities

The following are appropriate sensitivities that should be undertaken if practicable and relevant:

- Load growth – reasonable low, medium and high forecasts;
- Reasonable variations in the size, timing, location, capital and operating costs of:
  - The proposed project and alternative projects;
  - Committed, anticipated and modelled projects, including transmission projects required to meet deterministic reliability standards;
- Different values of unserved energy – (initially, $10,000/MWh and $30,000/MWh but to be replaced by values published by the Board);
- Discount rates;
- Weather patterns – given implications for hydro plant bidding;
- ‘Realistic’ generator and demand-side bidding strategies; and
- Key input variables into the calculation of competition benefits.

Annex 2: Grid history and future development

The New Zealand high voltage transmission network covers around 12,000km and extends across the entirety of both islands. It has essentially remained unchanged since the end of the 1990s. Transpower believes that the network now needs significant investment in order to meet New Zealand's future requirements.

History of grid development

The development of the New Zealand transmission system commenced in the 1920s when the first 110kV line was built in the lower North Island. Over the next 10 years, all North Island generators were connected to a single system. By the late 1930s, similar connections had been made in the South Island.

In 1953, the "backbone" of the modern North Island network was developed, with a 200kV line between Auckland and Wellington. The 220kV network in the South Island began with a line from Roxburgh to Islington, extending to Nelson by 1958. The high voltage direct current (HVDC) link between the North and South Islands was developed in the mid-1960s. The last 220kV line project was completed by 1990 at the same time as a major upgrade of the HVDC link that nearly doubled its capacity.

Today, apart from the HVDC link, the backbone of the New Zealand network remains comprised of 220kV lines, generally single-circuit in the North Island and a mix of single- and double-circuit towers in the South Island. A significant number of 110kV lines serve secondary load centres or support grid reliability.

Transpower expectations for grid development

Transpower considers that a total sum in the region of $1.5 billion will need to be invested in transmission assets by 2010 and a further $100 million per annum thereafter until 2020.[24] These investments will be subject to review by the Board, according to the investment criteria and processes developed in the course of this assignment.

The main reason for these proposed upgrades appears to be that, despite steadily increasing electricity demand, no major transmission line or system reinforcement projects have been carried out by Transpower over the last 10-12 years. Many parts of the system suffer from high losses and there are a number of security risks – notably around the Auckland isthmus where the loss of the 220kV transmission line would result in major blackouts – perhaps for several days. Constraints on Transpower's network are also significant, amounting to more than $50 million per annum over the last few years.

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24 Transpower, Ralph Craven, "The National Grid - Core New Zealand Infrastructure, Presentation to IPENZ Conference", Christchurch, 26 March 2004.

Transpower has identified a number of measures for addressing what is already perceived to be a shortfall in grid capacity. In the short-term, Transpower is focusing on:

- "re-rating" transmission lines – that is, reviewing the capacity that individual lines can safely transport; and
- "tactical" upgrades – grid enhancements for completion by 2005 aimed at upgrading and extending the life of existing infrastructure.

In the longer term, Transpower considers there is a need to upgrade the core grid to 400kV, starting with the most heavily loaded and growing parts of the existing 220kV backbone network. Three major investment projects identified by Transpower for completion by 2010 include:

- upgrading transmission capacity into Christchurch and the Canterbury region by replacing the existing Livingstone to Islington 220kV circuit with a new 400kV line from the Waitaki Valley to Christchurch;
- a similar upgrade of the core grid around Auckland involving the replacement of 220kV circuits with a new 400kV circuit from South Waikato to South Auckland and replacement of some 110kV lines with 220kV lines; and
- the modernisation and upgrade of the inter-island transfer capacity of the high-voltage direct current (HVDC) link between the North and South Islands.

Annex 3: Efficiency, consumer and producer surplus and competition benefits

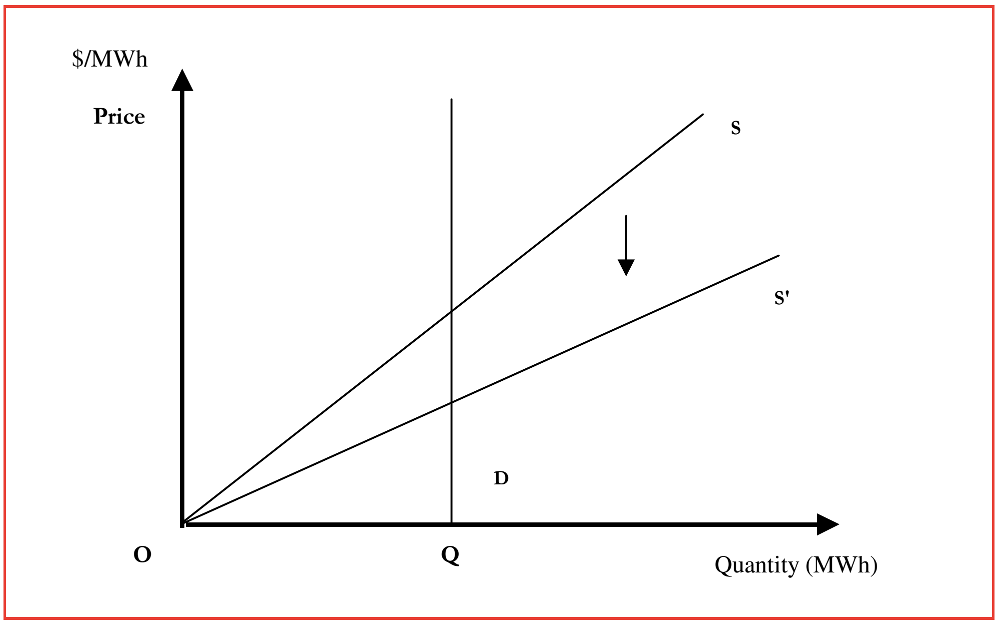
Productive efficiency

Productive efficiency is concerned with the costs of production – whether output is produced with the minimum cost combination of inputs. For example, improving the heat-rate of a gas-fired turbine would improve productive efficiency of that plant.

At the same time, productive efficiency can refer to the supply of *total market demand* at least-cost. For example, a transmission augmentation that overcame pre-existing constraints and allowed lower-cost plant to be dispatched in place of higher-cost plant would improve the 'productive efficiency of the industry'. In Figure 6 below, a downward shift or clockwise rotation of the supply curve (S) from the origin (0) would represent an increase in the productive efficiency of the industry.

This concept is also reflected in the requirement for the GIT to take account of transmission alternatives in the assessment of an augmentation.

Figure 5: Productive efficiency



Allocative efficiency

Allocative efficiency refers to the allocation of resources to their highest valued use. In a competitive market, allocative efficiency would imply that the market price was equal to the incremental or marginal cost of producing the final unit of output.

Figure 6: Allocative efficiency and maximisation of consumer and producer surpluses

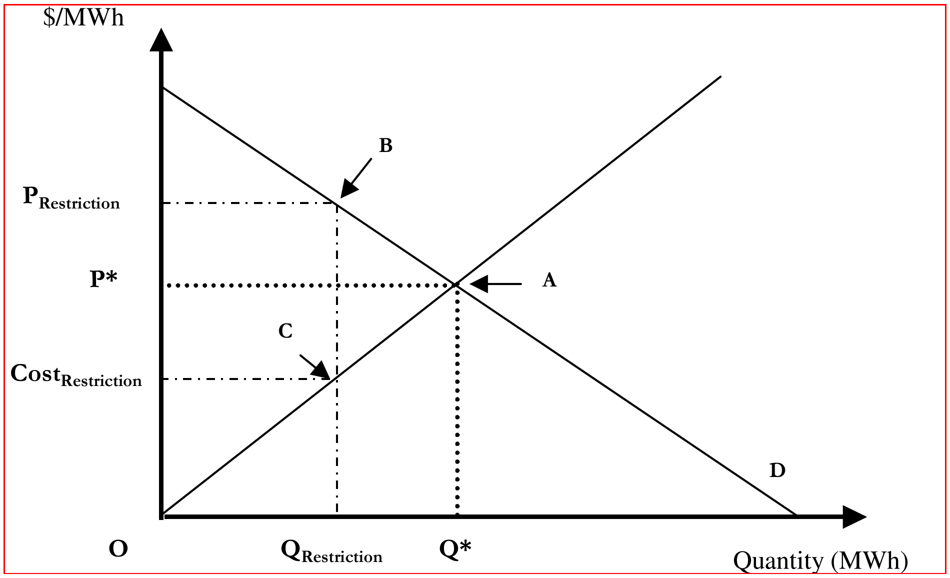


Figure 6 shows the price of electricity on the vertical axis and the quantity of electricity produced and consumed on the horizontal axis. Consumer demand for a normal good such as electricity decreases as the price increases. Meanwhile, the cost of producing electricity generally becomes higher the more electricity is supplied (assuming capital and technology does not change); hence, the supply curve slopes upwards. Allocative efficiency is generally maximised where consumers' willingness to pay for the last unit of a good or service sold is equal to the (incremental) cost of producing that last unit. In a perfectly competitive market, this point is where demand and supply intersect, which sets the market price and quantity traded (point A above).

Consumer and producer surplus

The gap between the willingness of consumers to pay (the demand curve) and the cost of supply (in this case the supply curve) represents the value or welfare obtained by the production and sale of electricity.[25] This can be represented by the area PAO in Figure 6. If there was some restriction on the quantity of electricity that could be sold below the equilibrium quantity ($Q_{restriction}$), and this was not due to technical reasons, total value would be reduced to PBCO, resulting in what is known as a 'deadweight loss' of welfare or efficiency of BAC. This restriction in output would not be allocatively efficient because consumers would be willing to pay more ($P_{restriction}$) for the next unit of electricity (the unit to the right of $Q_{restriction}$), than it cost to produce ($Cost_{restriction}$).

Total value can be split into shares according to whom the value accrues. Consumer surplus refers to the difference between what consumers are willing to pay for something and what they are required to pay. For example, many consumers may value electricity well above the tariff they must pay to receive it. In Figure 6 (ignoring the supply restriction), this is the area PAP*. Producer surplus refers to the difference between what producers receive for something and what it cost to produce it. For example, the market price for electricity may be well above what it costs some generators to produce it. In Figure 6, producer surplus is the area P*AO.

Dynamic efficiency

Dynamic efficiency refers to the allocative efficiency of decisions over time. This introduces two further variables:

- *Time value of money*: Money usually has a higher value today than tomorrow. This means that future benefits and costs (in dollar terms) need to be discounted to compare with current (dollar) benefits and costs.
- *Investment*: Investment decisions are considered – in the short term, the stock of capital and technology is assumed to be fixed. However, in the long term, capital and technology can vary – in other words, investments are made.

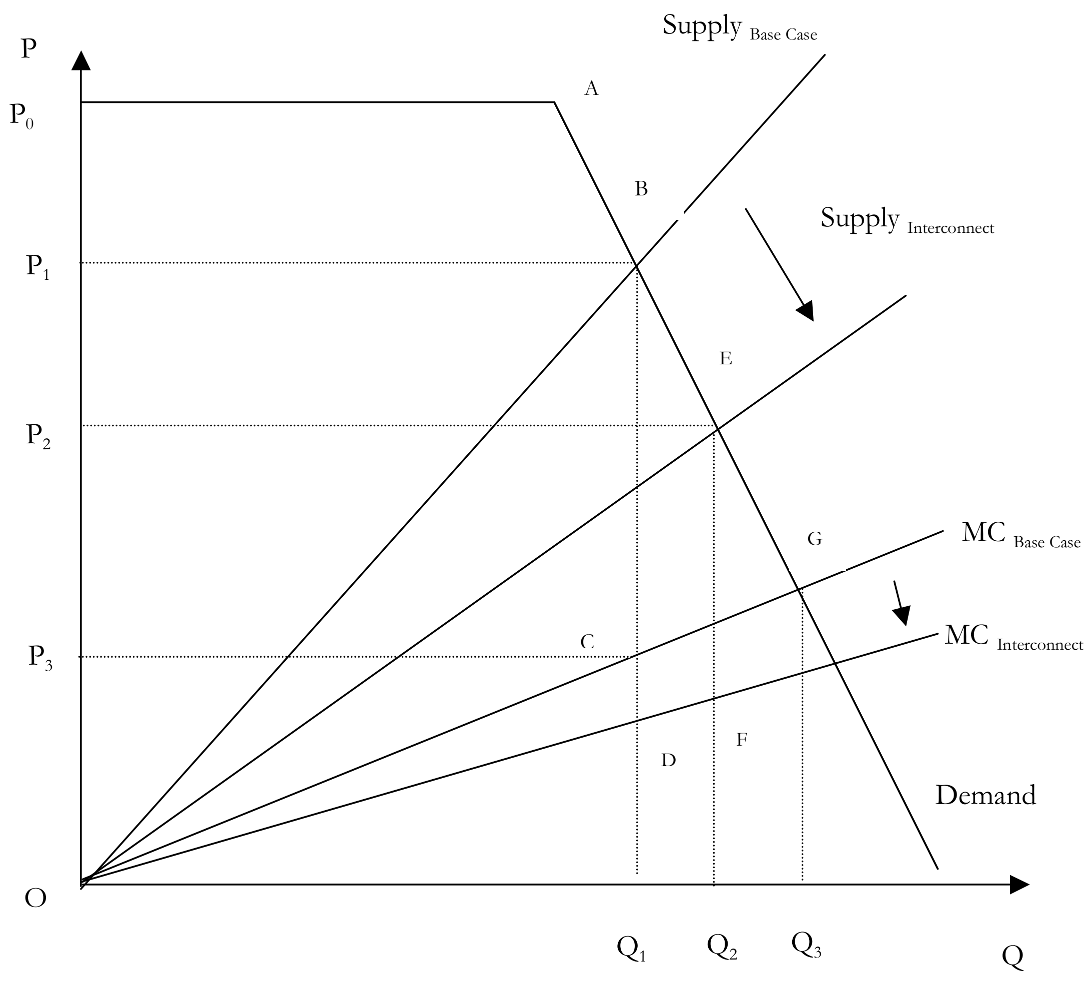
In theory, dynamic efficiency can be considered merely as forms of the different types of efficiency that were discussed above. All dynamic considerations do is to make the element of time explicit.

25 This is only a partial equilibrium impact. The general equilibrium surplus would include all surpluses across the economy derived from the production and sale of electricity.

Competition benefits

Figure 7 illustrates the concept of competition benefits.

Figure 7: Competition benefits



Due to the presence of market power, the market supply curve is higher at all points than the corresponding marginal cost of supply.

Prior to the interconnector, market equilibrium is at B and total market benefits are P_0ABCO.[26] The area P_0ABP_1 is consumer surplus and the area P_1BCO is producer surplus.

26 The point B and quantity Q_1 has to be used because although in a competitive market, demand would be at Q_3, in a market with market power, Q_1 is the observable level of demand.

Then assume that the interconnector has the dual effect of reducing the marginal cost of supply and increasing competition, thereby rotating both the supply curve and the MC curve clockwise.

If only the fall in costs of competitively supplying the load is taken into account (conventional market benefits), then taking demand as given and ignoring fixed costs, gross market benefits are now P_0ABDO and the net market benefits of the interconnector are CDO. As the diagram shows, it is not practicable to take demand response to higher prices into account, because the analysis artificially abstracts market power away from the determination of market benefits – there is no demand curve going through point C. Forecast demand (Q_1) is based on current market prices (P_1), not on what the price would be in a competitive market (P_3).

However, incorporating the effects of competition on *actual market outcomes* and considering demand elasticity, the new equilibrium is at E and total market benefits are P_0AEFO, an increase of BEFOC over the base case and an increase of BEFD over the conventional calculation of the net market benefit of the interconnector. In practice, the marginal cost curves may vary slightly, so the better way to calculate the 'competition benefits' of an augmentation is to subtract conventional market benefits (CDO) from total market benefits (BEFOC).

The competition benefits of the next best alternative to the interconnector then need to be determined to enable an appropriate comparison between the options.

Annex 4: Real options analysis

A standard discounted cash flow (DCF) or net present value (NPV) analysis is based on expected future cash flows.

According to Copeland and Antikarov, DCF ignores the fact management has many options at different stages of the project. The project can be abandoned after the initial design phase, it can be expanded if it does better than expected or it could be deferred. 'When optimally exercised, all of these options provide flexibility that adds to the value of the project.'[27] A proper analysis of real option values can affect the valuation of a project, the relative valuations of competing projects, the structuring and operation of a project and the timing of a project. In an environment of uncertainty, it may be worth including real options in the comparison and assessment of projects under the GIT.

In this context, there are a number of reasons why the application of a real options approach to the GIT is likely to be problematic and may not be worthwhile.

First, there are a large number of options that would need to be considered. There is the option to delay an augmentation, as well as the option to expand or restructure the project. In addition, the non-transmission alternatives will also have embedded options, all of which need to be valued for consistency.

Second, valuation of options pertaining to electricity investments may be difficult. For example, a line built between two nodes is effectively an option to buy electricity at one node and sell it at another. This means valuation of a transmission line as a real option requires not only a single price process for electricity, but a bivariate process for electricity at the two nodes that are being connected. Further, real option theory draws on valuation frameworks that were originally developed to value financial options. The Black-Scholes formula gives the value of a standard 'call option' on a stock – a call option being a right but not the obligation to buy the stock at a certain price. This formula is based on two key assumptions:

- the returns of the underlying stock are normally distributed; and
- the underlying stock can be continuously traded and stored.

Neither of these assumptions holds for electricity, because electricity is not storable and its price changes are far from normally distributed (characterised by jumps, seasonalities, mean reversion and severe skewness).

Third, the costs of an option need to be valued along with the benefits. For example, the option to delay an augmentation may have some benefits – namely, allowing a more informed decision to be made as time passes and more information comes to light about the value of the project. However, it may also have costs if, say, reliability were compromised or other, less worthwhile projects

[27] Copeland, T.E and V. Antikarov, *Real Options: A Practitioner's Guide*, 2001, Texere, New York.

proceeded ahead of the augmentation. If the costs of delay were ignored, it would be optimal to delay the project indefinitely.

Finally, for the sake of clarity, it should be emphasised that real options *cannot* be incorporated in an ordinary NPV analysis simply by adjusting the discount rate. The effect of real options is to change the pattern of cash flows produced by the project and to change its risk profile. Consider, for example, a gold mine where the extraction cost exceeds the expected gold price. A standard NPV analysis would conclude that the expected net cash flows are negative and that the mine should not proceed. Changing the discount rate would not affect this conclusion. A proper real options analysis takes account of the fact that the mine can remain closed unless and until the gold price exceeds the extraction cost. If there is a positive probability of this occurring, the mine may have a positive value. Thus, real option values cannot be constructed simply by applying a different discount rate to the same set of cash flows that would be used in a standard NPV analysis.

All of these considerations suggest that it would not be impossible for the GIT to apply a real options approach to handling uncertainty, such an exercise would involve a great deal of subjectivity and complexity that may not be compatible with the need to provide a predictable and relatively transparent process for the evaluation of transmission investment.

At the same time, real options do exist and are potentially valuable. However, it is possible to incorporate at least an approximate value for various real options in a standard NPV framework by attempting to more accurately predict the project's net cash flows. For example, taking the gold mine from above, it would be necessary to identify the probability of the gold price exceeding the extraction price each period, and if it does, by how much. It may be that the extraction cost is $US400/ounce and the gold price will be $US450/ounce for 10% of the time, $US390/ounce for 50% of the time and $US370/ounce for 40% of the time. While the expected gold price is only $US388/ounce (below the cost of extraction), the fact that at certain time the gold price is above the extraction price gives the mine some value (assuming away capital costs). Therefore, by considering the project's net cash flows in *various scenarios* and properly weighting by the probability of each scenario occurring, it is possible to approximate the value of real options in an NPV framework.

Therefore, real options can by approximately incorporated in a standard NPV analysis by considering a range of sensitivities/scenarios for potential cash flows from the project and taking some view on the likelihood that those scenarios will occur.

Annex 5: Issues for consultation

The base case

Comments are invited on the most appropriate method for establishing the base case against which Transpower's proposals would be assessed.

Market development scenarios

Comments are invited on the following issues in relation to the construction of the market development scenarios:

(1) Whether the market development scenarios should include committed, anticipated and modelled projects for both the base case and the case of the investment (and its alternatives), as defined above.

(2) Whether the market development scenarios should be based on least-cost expansion, with alternative scenarios also considered, or whether they should take account of the fact that the market is not perfectly competitive, and if so how.

(3) The types of modelled projects that are appropriate for New Zealand.

Alternative transmission projects

Comments are invited on whether Transpower should be required to consider a range of transmission alternatives as well as non-transmission alternatives.

Identification of alternatives

Comments are invited on the whether alternatives should be identified in terms of 'substitutability' criterion or whether they are identified according to whether the alternatives provide similar outputs over a similar timeframe.

Number of alternatives

Comments are invited on the following issues in relation to the number of alternatives to be considered:

(1) Whether the number of alternatives to be considered in GIT for any one project should be limited.

(2) If the number of alternatives is to be limited, the basis on which this should occur.

Funding of alternatives

Comments are invited on:

(1) which party or parties should be responsible for investigating, developing and funding transmission alternatives assessed under the GIT; and

(2) the process for investigating, developing and funding alternatives that prove to be the best option available under the GIT.

Types of costs and benefits

Comments are invited on the following issues in relation to the types of costs and benefits to be considered:

(1) Whether the costs and benefits listed in Figure 3 are appropriate.

(2) Whether other costs and benefits should be considered and if so, the identity of those other costs and benefits.

Cost-effectiveness analysis

Comments are invited on the following issues in relation to the types of costs and benefits to be considered:

(1) Whether cost-effectiveness is appropriate for reliability investments where the project and its alternatives are expected to have identical or near identical benefits or differences in benefits are unlikely to be material in changing the ranking of investment options.

(2) Whether a cap of $10 million or another value should apply to the use of cost-effectiveness analysis for reliability investments.

Discount rate

Comments are invited on:

(1) Whether the appropriate discount rate to be applied under the GIT should be a rate that would be applied by a private investor in the electricity sector.

(2) In light of (1), what the discount rate should apply.

Timeframe

Comments are invited on whether a 20 year time horizon is appropriate for the consideration of the costs and benefits of projects.

Value of unserved energy

Comments are invited on whether a grid test assessment should be based on an initial central value of unserved energy of $20,000/MWh with sensitivities of $10,000/MWh and $30,000/MWh to be used where the size and cost magnitude of the project warrant the additional analysis.

Uncertainty

Comments are invited on whether the GIT should utilise sensitivity/scenario analysis to account for uncertainty in project cash flows. An investment should meet the requirements of the test if it maximises net benefits (or minimises costs) in the greatest proportion of reasonable scenarios.

Comments are invited on whether there are any variables other than those listed in section 6.4.3 above that should be considered when accounting for uncertainty in the cost-benefit analysis.

Competition benefits

Comments are invited on whether competition benefits should be included in the GIT, and if so, how they should be measured.

Materiality threshold

Comments are invited in relation to the following materiality threshold issues:

(1) Whether an absolute dollar approach should be used for setting the materiality threshold for application of the GIT.

(2) Whether the proposed threshold figure of $5 million is appropriate.

Investment contracts

Comments are invited in relation to the following investment contract issues:

(1) Whether the Board should have the discretion to allow proponents to contribute funds (for which they will receive no regulated return) to allow a project to pass the GIT.

(2) If the Board does retain such discretion, whether there should be any restrictions on the level of contribution.

Terms sheet

Comment is sought on whether the terms in Annex 1 adequate reflect the discussion in the body of the Discussion Paper, and the nature of any additions or changes.

Annex 6: References

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