OPTIONS CHOICES DECISIONS

UNDERSTANDING THE OPTIONS FOR MAKING DECISIONS
ABOUT NEW ZEALAND'S ELECTRICITY FUTURE

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Foreword

Energy is essential to New Zealanders' way of life. It is a critical factor for maintaining and raising our standard of living and driving the country's economic growth. Electricity is a key form of energy. Last year, electricity represented around 30 percent of New Zealanders' overall energy consumption. We take the supply of electricity for granted until it is not there. However, it is undeniably central to the functioning of our modern society.

Although there have been considerable improvements in the efficient use of energy, our demand for electricity continues to grow. Year on year, electricity consumption is increasing by around two percent. This growth is being led by New Zealand's expanding economy and growing population. The government's economic growth objectives mean that this demand growth should continue in the future.

In recent years, New Zealand's broader energy sector has been affected by significant uncertainty. The world oil market has been buffeted by geopolitical instability, climatic events and large increases in demand. New Zealand has been directly affected, given our reliance on international oil markets. Closer to home, the reduction in Maui gas reserves, coupled with uncertainty regarding future gas supplies, has resulted in sharp increases in the price of gas. This gas market shock has affected New Zealand's wholesale electricity sector, given the growth of gas-fired electricity generation over the last five years. Regulatory changes in the electricity sector have added to the uncertainty.

This report is Meridian Energy's contribution to providing quality information needed for making good decisions.

Government and its policy advisors require accurate information so that they can make informed policy decisions. Regulatory bodies and advisors need a thorough understanding of issues in the sector in order to develop appropriate regulatory structures. Industry participants require quality information to base generation investment decisions on, so that industry costs are minimised and electricity security of supply is ensured. And, electricity consumers need to understand the various issues in the industry so they are able to make well-informed consumer choices.

We have endeavoured to provide an objective perspective on the issues facing the industry and possible futures for the New Zealand electricity market. We have sourced our analysis of the wholesale electricity sector from in-house expertise and experience and from a range of external sources.

We have attempted to crystallise the key factors influencing the market in the years ahead and particularly the uncertainties that will shape the sector. We have sought to identify the actions that can be followed to resolve these unknowns.

I encourage other industry participants to contribute with their own analysis and data so that the issues shaping the sector are better debated and understood.

I hope that this report will form a valuable input into everyone's understanding of the issues facing New Zealand's wholesale electricity sector.

Keith Turner
Chief Executive
Meridian Energy

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1.0

Part A – Strategic Overview
Introduction

New Zealand's demand for electricity is expected to continue to grow strongly over the next 20 years. Demand side initiatives will meet or reduce some of this demand. A range of new generation investment will also be required.

This section of "Choices" examines the strategic issues facing New Zealand's wholesale electricity sector.

We begin by briefly reviewing the changes in New Zealand's electricity industry over the last 20 years. This is followed by an analysis of the likely growth in electricity demand over the next 20 years.

Two broad categories of response to this demand growth are reviewed:

- Demand side initiatives. These are initiatives that influence the amount of energy used by consumers. Our definition of demand side initiatives includes any opportunity to reduce demand at a distribution network level – either by improving energy efficiency, using alternative energy sources or through distributed generation alternatives.
- Supply side options. These are large-scale generation project options. Our analysis focuses on the economic cost of various generation forms and how New Zealand's generation mix may alter in the future under various scenarios.

Our key findings follow:

1. **Demand side options can help address some, but not all, of New Zealand's future electricity needs.**

   Some demand side options, in particular electricity efficiency initiatives, are an economic and environmentally sustainable approach to meeting New Zealand's demand for electricity. These will form part of the solution to meeting New Zealand's future electricity needs, but they are only part of the solution given the likely size of future electricity demand.

2. **New large scale electricity generation projects will be required to meet New Zealand's future energy needs and are likely to include a mix of generation technologies including renewables, gas and coal.**

   Further large-scale electricity generation projects will be required over the next 20 years to meet New Zealand's growing energy needs. Some current generation plant will also need to be replaced. Economic project cost is a key factor in determining which projects get built. In general, the economic cost variation between various projects of the same generation technology, whether a coal, gas or renewable generation project, is greater than the cost variation between technologies. From an economic perspective, this implies that New Zealand's future electricity production is likely to come from a range of generation plant.

3. **If significant volumes of low-cost gas are discovered in New Zealand there is likely to be more gas-fired plant in the future. However, this is unlikely in the short to medium term.**

   The future share of each generation type will depend on a number of factors, some of which are currently unknowable.

The biggest uncertainty is gas availability and price. A future scenario where significant amounts of low-cost indigenous gas are found, for example, another Maui sized field is discovered, has significant implications for the industry. Under this scenario it is likely there will be a greater proportion of new generation that is gas-fired with some renewable generation. However, this outcome is unlikely in the short to medium term.

4. **In the absence of a major gas discovery renewable generation is likely to fill a larger part of total new generation capacity.**

Renewable generation is likely to fill a larger part of total new generation capacity if a large, low cost gas discovery is not made. Under these scenarios, the best new generation projects will be wind farms in prime locations, hydro generation in prime locations and geothermal expansion projects. These projects have the advantage of being environmentally sustainable. However, there are only a limited number of prime, "consentable"[1] renewable projects available.

5. **Project economics are an important factor driving the mix of generation projects. However, there are other considerations that determine the selection of projects.**

Although the cost of various generation project options is a key factor in determining project selection there are also other important considerations. For instance, the ability of a generation company to gain access to land and to obtain appropriate resource consents is another key factor that affects the viability of a project.

6. **Not all renewable projects are created equal; there are a limited number of "prime" projects. Projects that are defined as "good" may require some form of incentive or favourable regulatory environment to get across the line.**

There are only a small number of wind, hydro and geothermal projects that fit into the "prime" category. Many are defined as projects in "good" locations. Incentives may be required for these projects to be viable economically, particularly if large amounts of low cost gas are found. For instance, a policy environment where the cost of carbon is properly reflected is an important avenue for supporting these projects.

2 Electricity is Essential to our Modern Economy

The electricity system, from generation to local distribution, is infrastructure critical to the New Zealand economy. Over more than a hundred years, electricity has shaped how New Zealanders live and work. Electricity has become so central to modern life that there are often no substitutes.

Reliable and cost effective access to electricity is fundamental to the ongoing progress of New Zealand. It is a key element in delivering New Zealanders' standard of living. Electricity is an essential ingredient for all parts of the economy and society.

The future electricity outlook is determined by growth in demand and supply, and the design of the policy and regulatory framework. It is these topics we turn to next.

3 The New Zealand Electricity Industry – Background

Over the past 20 years, New Zealand's electricity industry has undergone substantial structural change. In the mid eighties, the Ministry of Energy was restructured, with the generation and transmission assets of the Ministry being transferred to the Electricity Corporation of New Zealand (ECNZ). ECNZ was set up as a company under the State-Owned Enterprises (SOE) Act 1986. Transpower was subsequently split out of ECNZ as a separate SOE to perform the functions of transmission asset owner and system operator. ECNZ became the owner and operator of all large-scale generation facilities.

Over the same time period, local Electricity Supply Authorities (ESAs) were corporatised. Prior to this ESAs owned and operated the local lines networks, and small amounts of generation and electricity retail functions. In 1998, these companies were required to split out their retail businesses.

In the nineties, ECNZ was split into Contact Energy (1996) and then in 1999, into Meridian Energy, Genesis Energy and Mighty River Power. Contact Energy was privatised in the same year. The other three companies remain SOEs today.

A key outcome of the restructuring process was the separation of the natural monopoly elements of transmission and distribution from the contestable elements of electricity generation and retailing. The formation of several electricity generation companies enabled the development of a competitive wholesale electricity market.

Regulatory processes have also developed in parallel with these structural changes. Industry self-governance processes were successfully established for the wholesale electricity market, which began operation in 1996. After several years of operation, it became apparent that an overarching regulatory framework was required to monitor the market and to enable transmission investment decisions. Attempts by the industry to develop a self-regulatory framework failed and the government acted to establish the Electricity Commission, an industry-specific regulator, in 2003. The Commission is responsible for overseeing transmission activities, administering the operation and development of the wholesale electricity market and ensuring electricity security of supply.

The main players within the current industry delivery chain include:

- Electricity generation companies. There are six major generation organisations. Three of these companies are SOEs: Genesis Energy, Meridian Energy and Mighty River Power. Contact Energy, TrustPower and Todd Energy are privately owned.

[1] We use this term to describe the ability of a project to obtain an appropriate Resouce Consent.

- Transpower, an SOE transmission owner and system operator.
- Electricity lines companies. These organisations provide local distribution services between Transpower and consumers. Vector is the largest lines company in New Zealand.
- Electricity retailers. These companies have the supply relationship with most electricity consumers. Currently, most of New Zealand's retail activities are owned by the six largest generation companies.
- Major industrial organisations and end consumers.

Apart from the Electricity Commission, the Commerce Commission currently manages information disclosure and price setting regulations over all lines companies, including Transpower. The Commerce Commission also sets quality thresholds.

4 Electricity Demand Growth in New Zealand

4.1 Electricity Demand Growth to Date

New Zealand's demand for electricity has grown consistently over the last 20 years. Electricity consumption has increased from approximately 27.7 TWh in 1985 to 41.5 TWh in 2005, an average growth rate of 2.2 percent per annum.

Over the last 20 years, the growth in electricity consumption has been driven primarily by a combination of two factors:

- Population growth.
- Economic growth measured by Gross Domestic Product (GDP). Electricity is an important factor of production in energy-intensive industries such as dairy farming, forestry, metal smelting and agricultural-based products. In addition, income is an important driver of electricity demand; GDP is one measure of income.

The relationship between electricity demand and GDP is shown in Figure 1.

Overseas, electricity price is also an important factor affecting electricity demand. To date, price has not had a significant impact in New Zealand. Economists refer to this as "demand inelasticity". There are three main reasons for this:

- Price has been historically low by world standards. Until the last few years, changes in price have been modest.
- Residential consumers are on fixed-price contracts; these are usually reviewed annually. This lack of price information limits demand responses.
- There are no energy substitutes in many applications.

However, wholesale electricity prices have increased significantly over the last few years. There are two main reasons for this. First, the gas contracted under the Maui Gas Contract is running out. The period of low gas prices driven by this contract is ending and gas-fired generation is using gas supplied at a higher market price. Secondly, New Zealand's cheapest generation options have been exercised. New generation plant will inevitably be more costly.

Information presented later on the cost of new generation shows that there will continue to be upward pressure on the wholesale electricity price in the medium term, unless a significant, low-cost indigenous gas discovery is made.

As the wholesale electricity price increases, we expect it to have a greater impact on electricity demand. Amongst other things, higher prices should encourage improvements in energy efficiency.

4.2 Historic Response to Meeting Demand Growth

Historically, electricity demand growth has been met from a diverse range of fuel sources with a heavy emphasis on renewables – particularly hydro energy. Around 60 percent of New Zealand's electricity is produced from renewable resources. This result is a positive outcome from an environmental sustainability and climate change perspective. However, from time to time it has led to New Zealand being susceptible to climate-related risk, especially during dry years.

The strong base of hydro generation has been supplemented by geothermal and more flexible "hydro-firming" thermal generation from Meremere, Marsden A (both now decommissioned), New Plymouth, Huntly and more recently combined cycle gas turbine stations in Auckland and Taranaki. Thermal generation has provided the New Zealand power system with the flexibility required to provide the ongoing balancing of supply and demand across a broad range of hydrological sequences. In the past, these sequences have varied as much as 25 percent above or below average.

4.3 Recent Response to Meeting Demand Growth

Recently there has been debate over the effectiveness of the wholesale electricity market to deliver timely investment. While this debate is likely to continue, the fact is that significant generation capacity has been added to the system since the market began operation in 1996. Figure 2 sets out annual and cumulative new generation capacity (including decommissioned generation capacity) versus new cumulative demand growth since 1996.

This graph shows that the wholesale market has operated so that additional capacity has been commissioned in response to demand growth. Generation in the first few years was already committed prior to the establishment of the market. However, the market has operated since this time to ensure electricity security of supply through the provision of additional capacity.

As expected, the margin between additional capacity and additional demand tightened in the early 2000s in response to a period of capacity over-supply. However, the projected margin of capacity over demand in 2007 is expected to be similar to the margin experienced in the late 1990s. This fluctuation is a natural consequence of the lumpy nature of new generation plant.

FIG 1: **NEW ZEALAND ELECTRICITY DEMAND AND REAL GDP, 1946-2005**

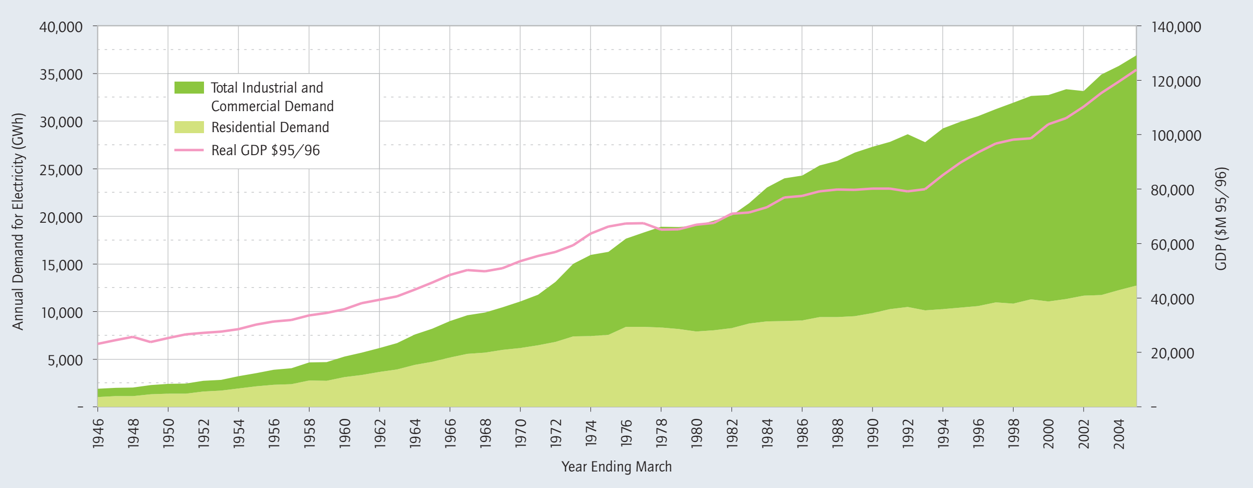
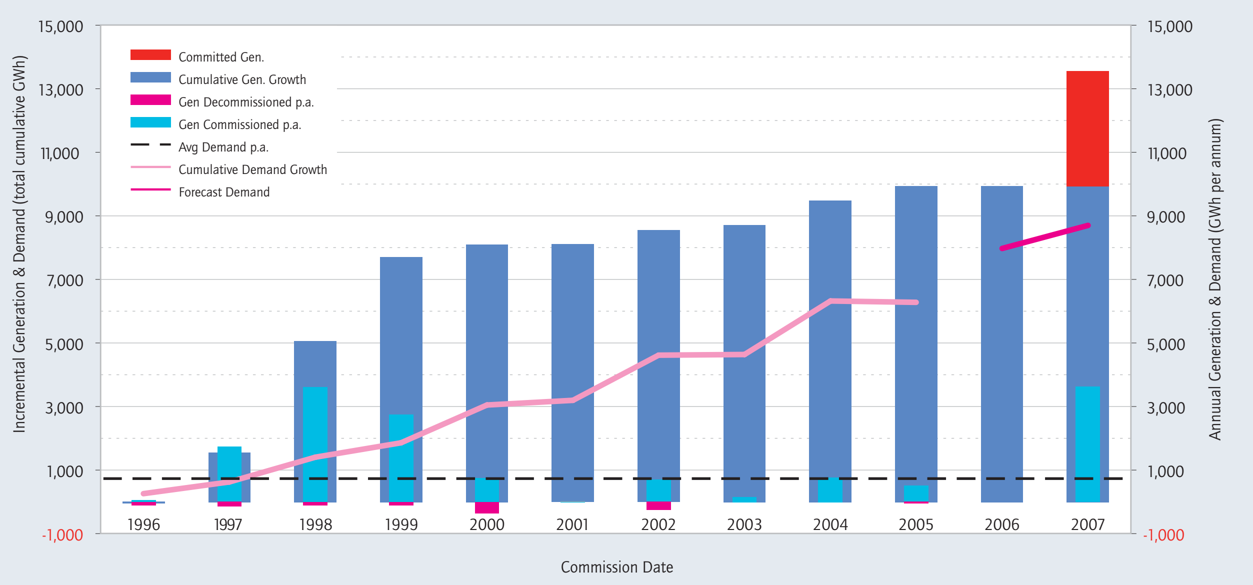


FIG 2: **NEW GENERATION CAPACITY AND DEMAND GROWTH, 1996-2007**



Other related observations on the market include:

- new generation capacity has exceeded demand growth since 1996
- generation has been developed utilising a range of technologies and "fuelled" by a range of energy sources including gas, wind, hydro and geothermal
- generation investments have been implemented by all of the five major generators.

4.4 Future Electricity Demand Growth

We expect that electricity demand will continue to grow in response to GDP growth and population increases. The government's broad economic objective is to return New Zealand's per capita income to the top half of the OECD. This objective will require New Zealand's economic growth rate to be consistently above the OECD average growth rate for a number of years.

However, it is likely there will be some "decoupling" of GDP and electricity growth over time as:

- the New Zealand economy matures and there is an increased focus on value-added products
- electricity prices rise
- there is an increased focus on energy efficiency.

FIG 3: **ELECTRICITY DEMAND AND GENERATION PRODUCTION. 1969-2028**

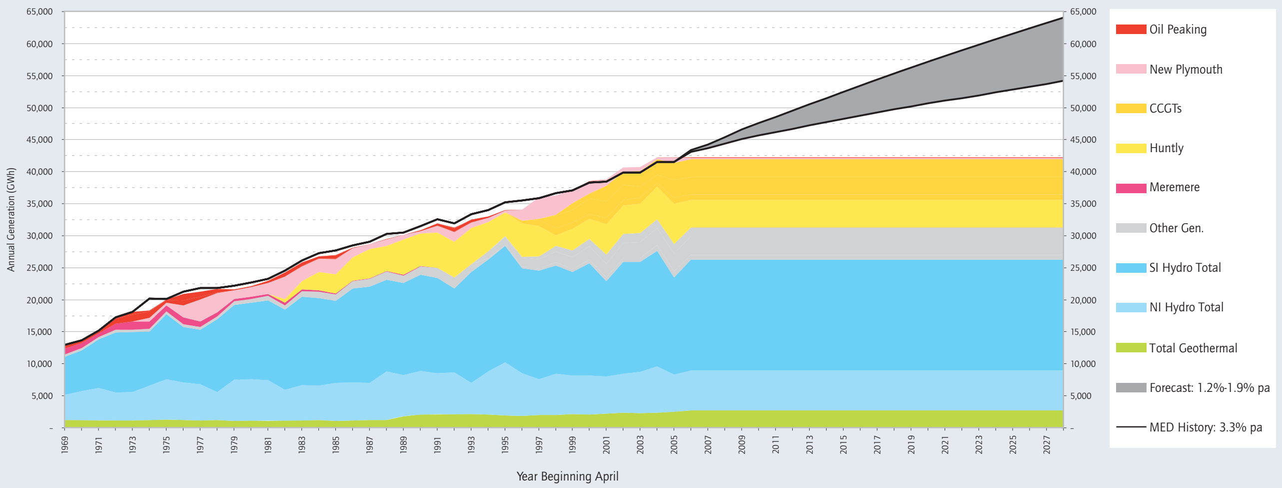


TABLE 1: **POTENTIAL NEW GENERATION OPTION**

Wind	Geothermal	Hydro	Other
Gumfields	Ngawha extension	Mohaka	e3p
Pouto	Kawerau	Toronui Mini Hydro	Rodney PS
Te Uku	Rotokawa extension	Mokau	Rodney PS Stage 2
Taharoa	Mangakino	Kaituna	Marsden B
Taumatatotara	McLachlan PS	North Bank Tunnel	Southdown Extension
Mokairau	Te Mihi Drilling	Hawea Gates	Atiamuri Landfill
Titiokura (Unison)	Ohaaki Drilling	Lake Rochfort	Horotiu Landfill
Te Waka	South Tauhara	Gowan	Whareroa Cogen.
Titiokura (HBWF)		Mokihinui	Greymouth 4xGT
Tararua 3 (T3)		Coleridge Upgrade	Buller Coal
Te Rere Hau Stage 1		Wairau	Burwood Landfill
Te Rere Hau Stage 2		Dobson	Nelson Landfill
Turitea		Waipori Deep Stream	Otahuhu C
Motorimu		Rangitata Diversion	
West Wind		Manapouri Refurbishment	
Puketiro			
Stoney Creek			
Hayes			
Lake Mahinerangi			
Rock & Pillar			
Cairnmuir Hill			
White Hill			
9,935	2,475	3,360	12,130
Total GWh p.a.			**27,900**

The key area of uncertainty regarding demand growth is the rate of growth and how specific regions will vary in response to local economic conditions. At a national level, our view is that electricity demand growth will continue to be significant. The rate of growth will require new base load generation to be installed in the order of 500-900 GWh per annum.

We expect electricity demand in 2030 to lie somewhere between 55,000 and 65,000 GWh. This equates to an increase of 30-60 percent in generation capacity.

Figure 3 illustrates New Zealand's historical generation output across all major sources against demand growth. The demand growth is forecast from 2006 as a potential range. Even with the most conservative demand growth assumptions, which include a high degree of demand side initiatives such as energy efficiency programmes (see section 6), there is a significant gap between supply and demand. The need for additional generation capacity is clear.

4.5 Generation Options Currently Under Investigation

A range of new generation proposals have been put forward by both established participants and new entrants to the industry as market conditions have tightened. These proposals are at various stages, from initial pre-feasibility proposals through to committed projects.

There have been public announcements relating to 22 wind farm proposals at different stages of evaluation, planning or construction. There are also 15 hydro, 8 geothermal and 13 natural gas, coal, cogeneration or landfill gas options at various stages. These projects have a combined production of around 27,900 GWh. These projects are listed in Table 1. Projects highlighted in red are committed. In addition to these projects, there are others that are not in the public arena.

Many of these projects are unlikely to proceed, at least in the short to medium term. However, the total potential electricity production of this list is far greater than likely growth in demand of around 500-900 GWh p.a.

The volume of new generation projects publicly known to be under investigation suggests a number of points:

- committed projects should meet demand growth until 2009
- market signals to investigate and build new generation are being acted upon – in all parts of the country, from diverse sources of generation, and from multiple companies
- although it is uncertain which of the projects listed in Table 1 will proceed, appropriate levels of electricity security of supply are likely to continue well into the next decade

It would appear that New Zealand should be well served in terms of:

- available and diverse generation options
- a wide range of companies willing to commit significant resources in the electricity industry.

5 A Framework for Electricity Decisions

It is generally acknowledged that an electricity system should be managed in a manner that encourages efficient production and energy use. The system should provide a security of supply outcome that is consistent with consumers' willingness to pay. These economic objectives are necessary for a well-functioning electricity sector.

An electricity system should also be managed to meet the government's environmental sustainability objectives. In New Zealand, this outcome is delivered through the Resource Management Act. It is also realised through other frameworks such as the Crown's climate change policy.

Because of the critical role that electricity plays in society, governments typically have other, broader, policy objectives for the sector such as particular social outcomes. For instance, the New Zealand government has social equity objectives such as the availability of electricity to all classes of consumer and fairness considerations.

These broad objectives are espoused in a number of government policy documents, including the government's Sustainable Development: Programme of Action and its Government Policy Statement on Electricity Governance.

The framework for meeting these objectives is discussed in the following sections.

5.1 The Economics of Investment Decisions

Under the wholesale electricity market structure, market signals should lead to efficient investment in new generation plant or demand side initiatives, including energy efficiency. The market provides signals for generation plant investment or additional demand side initiatives as the underlying demand for electricity grows.

The mechanism for this investment signal is discussed fully in the appendix "Economics of the New Zealand Wholesale Electricity Market". Generation or demand side decisions are based on the marginal cost of various options; the marginal cost is the cost of producing an incremental unit of output.

Short run marginal cost

For current electricity supply the short run marginal cost (SRMC) of plant tends to drive the market price and plant operation. This marginal cost comprises fuel (including the option value of fuel such as the value of water storage and coal stockpiles) and other variable operating costs – costs that can be avoided in the short term.

Long run marginal cost

For future supply, where further generation investment or demand side options are necessary to meet growth in demand, the long run marginal cost (LRMC) is more relevant. The LRMC of a new power station is the total marginal cost of producing electricity from the plant. It includes SRMC plus fixed costs, in particular the capital investment cost of the station. In this report we have taken the LRMC of a plant to be equal to its (levelised) unit cost. Refer also to the glossary for a definition of these terms.

From an economics perspective, the next initiative required to meet incremental demand should be the lowest-cost option from the portfolio of potential generation and demand side projects available. The relevant measure of cost is long run marginal cost (LRMC). The LRMCs of potential demand side and generation initiatives are discussed in the following sections.

As New Zealand's electricity demand continues to grow, least-cost generation and demand side investment will be critical to maintaining downward pressure on prices. Consideration of the cost of various options is a key part of achieving the broader outcomes for the sector as detailed in various government policy documents.

These broader outcomes can be achieved by building on the LRMC investment signal. For instance, the government's climate change policy may be incorporated through a mechanism that prices the externality of carbon emissions. Other environmental objectives are largely addressed through the application of the Resource Management Act. Social and other objectives may be incorporated through appropriate regulatory design – for example, the requirement for retailers to provide low fixed-charge user tariffs.

5.2 Good Decision Making Requires Good Information

In order for good outcomes to occur, a necessary requirement is that parties involved in decision making have access to appropriate information and that uncertainty is minimised. These parties include generators, the transmission provider, policy makers, regulators and consumers. There should be clear signals for investment and policy should be made on a well-informed basis.

These signals are important irrespective of the industry structure. For instance, in the centrally planned era of the New Zealand Electricity Department, understanding of the costs of various generation and transmission plant was required so that planners could make appropriate investment decisions. In the current wholesale market structure, information is required so that generation companies can make efficient, least cost investment decisions and so a robust transmission network can be developed in a way that delivers security of supply and facilitates competition.

The difference in the two regimes lies not in the information required, but rather on how effectively this information is translated into rational decision making. Economists argue that centrally oriented structures tend to lead to muted signals with inefficient outcomes. In contrast, a well-designed market structure should lead to more efficient outcomes, provided there is good information and regulatory certainty.

5.3 Future Uncertainties that Affect Investment Decisions

Electricity generation projects are capital intensive and costly. High-quality decision making by the industry requires uncertainty to be minimised. In recent times, New Zealand's electricity industry environment has been affected by a range of uncertainties, that have threatened the viability of new generation initiatives. These include uncertainty about gas availability and regulatory settings.

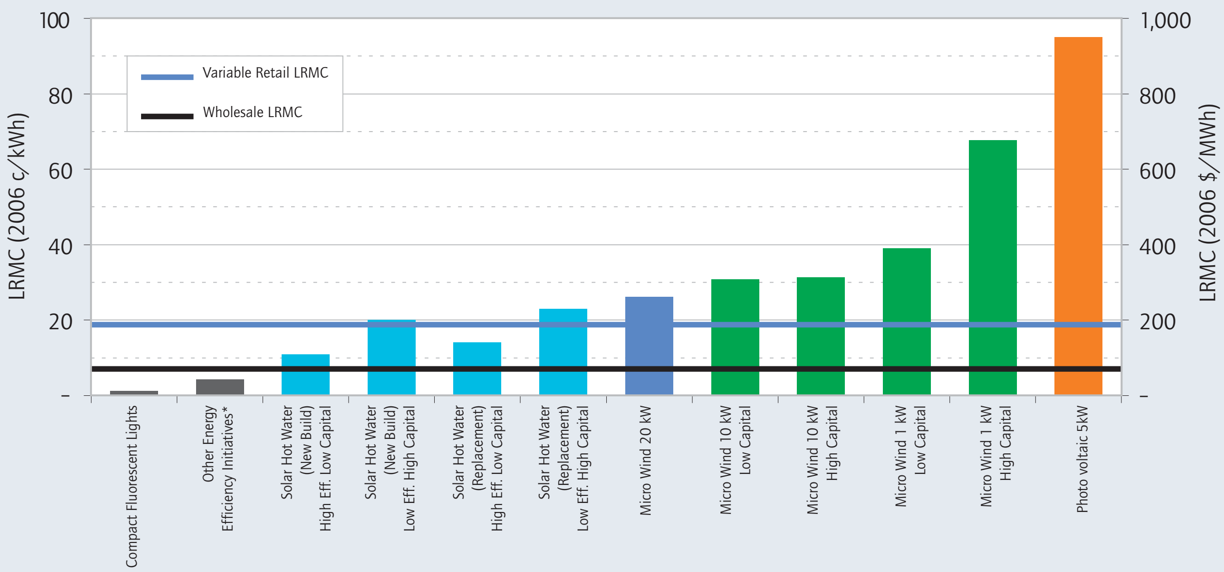
Gas availability has been a major uncertainty over the last several years following the redetermination of Maui gas reserves. As a result, Contact Energy is reconsidering its development of Otahuhu C, a proposed CCGT (Combined Cycle Gas Turbine) plant with a generation capacity of up to 400 MW. Genesis Energy is proceeding with e3p, another CCGT, but only on the back of a government guarantee that shares this fuel availability risk.

Little can be done to reduce this fuel uncertainty except by finding the gas or proceeding with alternative generation options such as wind. For instance, the government is attempting to stimulate further petroleum exploration through a number of initiatives. As discussed earlier, a number of renewable generation options are being developed. This form of risk is intrinsic to the energy sector and industry participants are in the best position to deal with it.

The other major uncertainty facing the industry is regulatory uncertainty. Since the 1980s, the electricity sector has been the subject of extensive regulatory reform. The latest major reform was the establishment of the Electricity Commission in 2003. Particular issues affecting generation decisions include:

- Uncertainty over climate change policy. The government reversed its decision to introduce a carbon tax last year. It is currently working on alternative policy options. A decision to introduce a price on greenhouse gas emissions will fundamentally affect the economics of various generation forms. Certainty in this area is required for parties to commit to new generation projects.
- Transmission issues. A robust transmission grid is fundamental to the

FIG 4: **HIGH-LEVEL DEMAND SIDE MANAGEMENT INITIATIVES LRMC COMPARISON**



* Note – other energy efficiency initiatives include household insulation and motor efficiency improvements.
Unit costs were sourced from the Electricity Commission's pilot programme publications.

operation of the electricity sector. A variety of transmission issues are uncertain, particularly given issues over the accountability and roles of Transpower, the Electricity Commission and the Commerce Commission. Certainty on these issues is required for some new generation projects to proceed. The government's recent policy statements are a good start in this area, though further direction may be required.

- Lack of consistency in RMA issues across local body areas. Decision making on the management of resources is devolved to territorial and regional authorities. The rationale for this approach is that these authorities are better placed to make decisions about the use and development of local natural resources. However, these authorities take different approaches to various issues. There also tends to be a focus on local issues rather than the national interest, although national policy statements may be used to address this point. This lack of consistency creates uncertainties for generation investors.
- General regulatory uncertainty. The industry has gone through a protracted period of change, including major changes in the regulatory environment. The introduction of an industry regulator has been a useful step towards getting clarity on some issues. However, the regulatory environment needs to be more stable with an emphasis on clear communication between regulatory bodies and industry participants and a focus on "no surprises".

6 What is the Demand Side Management Potential for Meeting Future Demand?

There are clear opportunities for demand side management (DSM) initiatives to form part of New Zealand's energy future.

Our definition of DSM includes measures such as:

- energy efficiency initiatives (resulting in demand reduction)
- the use of other energy sources such as solar hot water heating
- small scale distributed generation (DG) options including micro wind turbines and photovoltaic generation.

As with supply side initiatives, the net economic benefits and market potential of DSM initiatives vary with the specific application. There are a number of DSM initiatives that are economic when compared with the unit cost of electricity supply from large-scale power plants. Some DSM options also enable management of the daily electricity demand profile.

In general terms, energy efficiency measures provide the highest degree of national benefit as many projects can be delivered below the unit cost of supply. Micro-generation is viable in isolated cases, although it is heavily dependent upon site resources and overcoming resource consent barriers. Figure 4 summarises the high-level unit cost comparison of the demand side management initiatives investigated in this report.

Section 15 has more detailed information on the costs modelled in this graph.

There are several DSM options that appear to be viable options when compared with current retail tariffs. However, these tariffs include variable price components that are actually related to fixed transmission and distribution costs. If there is significant uptake of DSM options, these tariffs would need to be rebalanced so that network costs were recouped. In this situation, a smaller proportion of the retail tariff would be avoided by investing in DSM options. Accordingly, comparison with the wholesale price is more relevant. There are fewer DSM options that are viable when measured against this yardstick.

Although there are some DSM options that appear economic, the effect on demand is relatively modest. The gap is illustrated in Figure 23 in section 15. The Electricity Commission has provisionally estimated that DSM options are likely to contribute the equivalent of around 1,800 GWh by 2026 (Electricity Commission, 2006c). The remaining energy balance "gap" (estimated to be over 13,000 GWh in 2026) will need to be met from medium- to large-scale power generation sources.

7 What are the Generation Opportunities for Meeting Demand?

New generation plant will be required to meet consumers' growing demand for electricity. Generation options that are proposed in the short term were listed in section 4. The factors that will affect the mix of generation in the longer term are discussed below.

7.1 Determining the Mix of New Generation

The mix of investment in electricity generation plant is determined by several factors. It is driven primarily by economic considerations:

- How do environmental factors affect the economics of particular projects? For instance, resource consent conditions may alter the economics of a project or prevent it from proceeding.
- How does climate change policy affect the economics of individual projects? Climate change objectives may be incorporated through some form of carbon price or appropriate regulatory regime.
- Given these considerations, what forms of generation make the best economic return?

Other broader objectives, such as social policy outcomes, may influence generation investment decisions through the regulatory environment.

In order to understand the economics of new generation investment over the long term, it is important to first understand the dynamics of various generation forms. As discussed, the New Zealand electricity system has some relatively unique characteristics. In particular, the sector is dominated by renewable generation, particularly hydro generation. This form of generation utilises New Zealand's abundant natural resources to deliver comparatively low-cost, low-carbon emission electricity. Because it has high capital and low operating costs, it is ideally suited to operating as baseload plant. However, at various times, the role of hydro generation may shift depending on hydrology.

The rest of production is sourced from thermal plant – mainly coal and gas-fired plant. This plant has lower capital costs and higher operating costs. Recently, as the gap between demand and generation capacity has shrunk, much of New Zealand's coal and gas plant has operated as base-load plant. In addition, this plant operates as base-load generation when hydrology conditions become tight. However, coal-fired plant in particular is physically more suited to being operated as a mid-merit or hydro-firming plant.

A mix of diverse generation forms is essential to the proper functioning of the New Zealand electricity wholesale sector. The various forms of generation have different attributes and perform complementary roles. A diverse range of generation types helps to limit the risks inherent in each form. As discussed, the most obvious example of such a risk is hydrology variability associated with hydro generation. Thermal generation can mitigate at least some of the risk of uncertain hydrology by operating harder when water inflows are low and easing off when they are high.

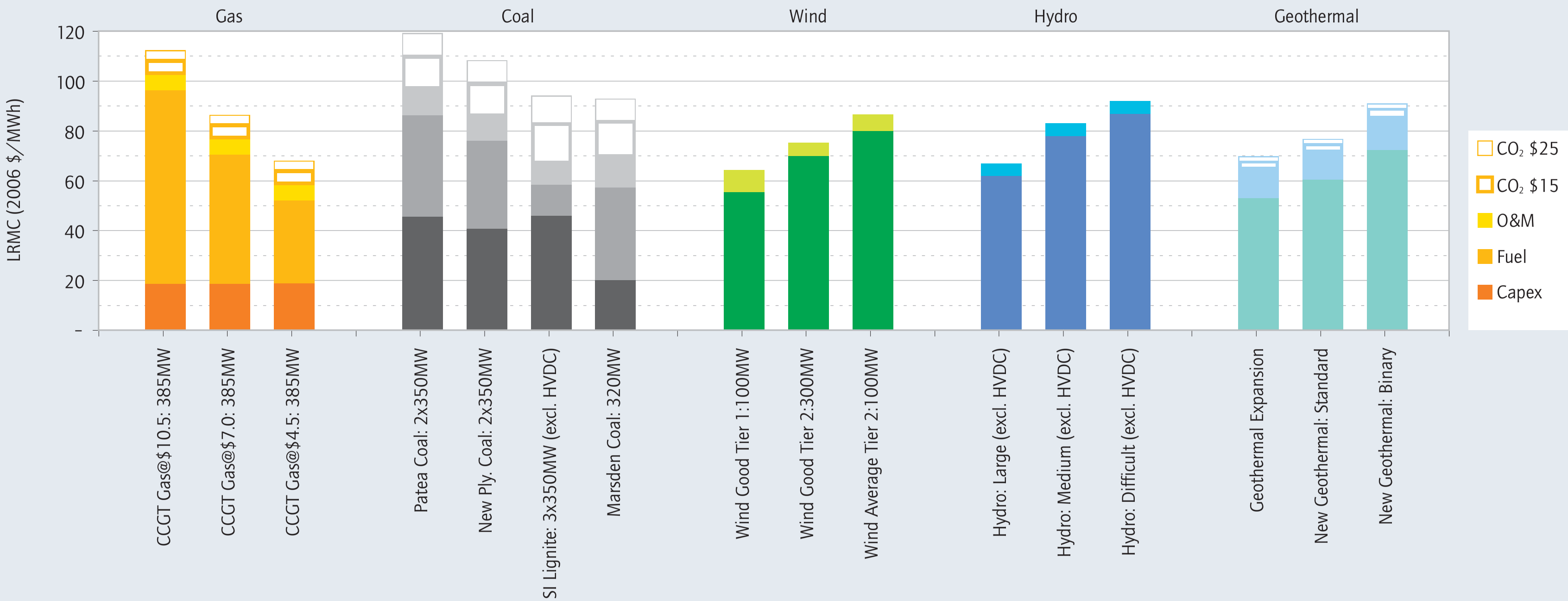
Over the next 20 years, new renewable generation projects will be dominated by forms currently under consideration: wind, hydro and geothermal. Other emerging technologies are likely to take at least 20 years to mature before they become part of New Zealand's electricity generation mix. Similarly, thermal options over this timeframe will be dominated by current coal and gas technologies.

Renewables generation will play a key role in meeting New Zealand's future electricity demand. However, the portfolio benefits of having a diverse mix of generation forms coupled with the relative economics of various specific projects means that further thermal generation is likely. The proportions in the mix will depend on the relative economics of the individual generation forms and their ability to meet the wider policy objectives for the industry. As discussed earlier, gas availability and price are major uncertainties facing the industry at the moment. How these uncertainties unfold will affect New Zealand's electricity generation mix over the medium term. Other factors such as the nature of the future regulatory environment and environmental issues will also influence this mix.

7.2 Economics of New Generation

The range of viable generation options will be limited by companies' ability to consent particular projects. Of the projects that can be consented, from an economic perspective the projects that should proceed are those with the lowest LRMC. We identified earlier the potential for other criteria also to affect final investment decisions. Even if there are such factors, project LRMC is a necessary starting point for considering other objectives.

FIG 5: HIGH-LEVEL GENERATION LRMC COMPARISON



This figure shows LRMC or unit cost estimates of various generic project types: respectively, gas (combined cycle gas turbines), coal (supercritical pulverised coal stations), wind, hydro and geothermal. The generic projects presented illustrate how LRMC varies within and between each generation form.

The bottom part of each bar represents the fixed cost portion of LRMC (i.e. capital costs); the coloured parts above this represent the variable cost potion (i.e. fuel and operations and maintenance costs). The remaining transparent portions on the gas, coal and geothermal bars identify the impact on LRMC of various carbon regime scenarios (specifically $15 and $25 ⁄ t CO_2e carbon price scenarios as proxies for the impact of possible carbon policies). These cost estimates are discussed in detail in Part B of this report.

The selected generic projects for each generation form show the variability between a "prime" project at one extreme (which has a lower LRMC) and an "average" project (which has a higher LRMC) at the other extreme. This variability is driven by location-specific issues for the various generation options and, in the case of thermal projects, fuel costs.

We have not included the impact of an HVDC charge in these LRMC estimates. Under the current transmission pricing methodology this charge adds up to $10 ⁄ MWh to the LRMC of South Island renewable opportunities and up to $5 ⁄ MWh for a lignite coal-fired power station in the South Island.

In the discussion that follows, we consider the LRMC of various generic generation projects to understand the possible mix of future electricity generation in New Zealand.

The estimated LRMC of various generic generation projects is summarised in Figure 5. In this report we use the (levelised) unit cost of a project as the proxy for the project's LRMC. A 9 percent post-tax nominal discount rate has been used. See the glossary for an explanation of these terms.

7.3 Implications of Project Economics on the Future Generation Mix

A number of conclusions follow from Figure 5.

1. **The LRMC spread within generation forms is generally greater than the variation among most forms.**

For each type of generation, there are a range of possible LRMCs depending on the characteristics of individual projects. There are favourable, or "prime", projects with relatively low marginal costs at one end of the spectrum. At the other end, there are projects with higher marginal costs. The LRMCs of various generation technologies tend to overlap each other. This overlap implies that there is the potential for a mix of new generation forms in the future. The proportions of the various generation technologies will depend on various factors. The factors with the greatest influence include gas availability and price. The nature of the regulatory environment, including the carbon regime, is another key factor.

2. **The make-up of LRMC differs between thermal and renewable projects.**

The LRMC of thermal projects is primarily driven by operating costs – particularly the costs of fuel. This is especially true for gas-fired generation. For example, the LRMC of new CCGT plant is driven largely by the delivered gas price, with capital costs having a much smaller contribution, around 20-35 percent. New coal generation has a larger capital component, around 45-60 percent, but is still affected significantly by variable fuel costs.

In contrast, the costs of all the renewables options are weighted much more towards fixed capital costs, typically 80-95 percent of LRMC.

3. **The relative economics of various potential generation projects is dependent on individual project characteristics and fuel costs.**

The LRMCs of various generation forms are driven by the characteristics of individual projects. Even within each generation technology, the LRMC range is relatively wide, reflecting the characteristics of individual projects. Factors that affect each form of generation are detailed below.

Gas

The economics of a combined cycle gas turbine (CCGT) plant are primarily driven by the gas price as delivered to the plant. Over time, this price will be set by the nature of future gas discoveries or the price of imported gas. Section 10 discusses gas generation issues in detail.

If a large gas discovery is made in a location with supporting infrastructure, for example on the west coast of the North Island, the wholesale gas price could be at the lower end of the scale – perhaps $4.50/GJ, depending on field economics. At this price, gas-fired new generation would dominate most other generation options. New generation would tend to be gas-fired, though there would be some renewable investment. There would be no new coal-fired stations. A price on carbon or other changes in regulatory settings alters this conclusion. The implications of introducing a carbon regime are discussed later.

Alternatively, if current gas contract price expectations persist, at around $6-7/GJ, then the CCGT LRMC would be approximately $70/MWh, excluding any carbon price. A greater range of renewable projects is economic under this scenario, as well as some coal options. There would be a mix of new generation forms. Again, a carbon regime potentially alters this conclusion.

A new CCGT plant running on LNG gas at delivered prices of $10-11/GJ is uneconomic, at least in the medium term. Importation of LNG in this price range only appears to be economic for re-firing existing gas-fired plant where the capital cost is already sunk.

Coal

The economics of new coal generation plant are much more site specific than CCGT gas plant – even when running on imported coal. The key difference is the specific infrastructure that needs to be developed to service particular coal plant options. Section 11 discusses coal generation in detail.

The cheapest greenfields coal generation option in New Zealand appears to be a large Southland lignite plant located next to the lignite coal fields at approximately $70/MWh, excluding the cost of carbon. However, this would require significant transmission upgrades to transport electricity to consumers. Other coal options are significantly more expensive than this. New North Island coal generation using imported coal is likely to sit somewhere between $85-100/MWh – mostly depending on the proximity to an existing large port.

Coal is likely to be particularly affected by the introduction of a carbon regime. In a scenario where there is a price on carbon emissions most new coal-fired generation projects are uneconomic.

Wind

The relative economics of specific wind farm projects are driven by the local wind resource, the scale of the development, complexity of the site and supporting roading and transmission infrastructure. As such, the LRMC of wind projects are highly site specific. Section 13 discusses wind generation issues in detail.

A site with an excellent wind resource (above 10 m/s) could have an LRMC between $60 and $70/MWh depending on the above factors – however there are only a handful of these sites nationwide with a potential of around 2,000 GWh.

A site with a good wind resource (over 8 m/s), reasonable scale and a location situated close infrastructure could have an LRMC between $75 and $85/MWh. There are likely to be a number of such sites throughout New Zealand, with combined potential of around 6,000 GWh.

Sites with an average wind resource that are distant from infrastructure or are small scale could have an LRMC in excess of $90/MWh. These sites are likely to be more plentiful.

Apart from site characteristics, wind farm economics are also affected by economic conditions at the time of committal. Key factors include exchange rates, steel prices and international turbine demand.

Hydro

Similar to wind, the costs of hydro are driven by the local resource and the ease or difficulty of particular sites. As such, the LRMC of hydro is highly project specific. Section 9 discusses hydro generation issues in detail.

Hydro projects are capital intensive and take a number of years to develop. As such, economies of scale are important for project economics. The LRMC of possible "economic" hydro generation options ranges from $65 to $100/MWh.

The bulk of remaining hydro opportunities are located in the South Island and are therefore impacted by HVDC charges that add up to $10/MWh to the LRMC. There is about 3,500 GWh of potential hydro at less than $80/MWh but nearly two-thirds of this is located in constrained parts of the transmission grid.

Geothermal

While the geothermal fuel resource is "free", finding and maintaining the resource for the life-time of the plant can be difficult and expensive. Sites and fields that have a proven track record are therefore more attractive than completely untested resources. Given this, a brownfields expansion of an existing project is typically the cheapest and most successful type of geothermal project. The Mokai extension project is an example of a brownfields expansion. These brownfields sites are possibly the cheapest of all of the new generation options with an LRMC estimated to be around $50-70/MWh. However such developments are limited largely to the eight key existing geothermal generation fields – up to about 2,500 GWh potential. Section 12 discusses geothermal generation issues in detail.

A new geothermal project on top of a good reliable resource could have an LRMC in the range of $75- 85/MWh depending on the technology selected. Beyond this, if the geothermal resource is either not ideal or deteriorates over time, then the unit cost can climb rapidly.

4. A robust transmission grid is required in order for the lowest cost generation options to proceed.

The location of new renewable and thermal generation is determined at least partly by the location of renewable resources and thermal fuel. Renewable generation is very site specific, with project economics hinging on the resources of individual locations. Thermal generation is also affected by location issues, with the cost of developing fuel supply chains and resource consent issues limiting practical location options.

In many cases, generation projects under investigation are remote from centres of demand, for example Southland lignite station options, North Island geothermal generation options and lower South Island wind farms. These generation projects are reliant on a robust transmission system to enable the transport of electricity to consumers.

The key transmission issue facing new generation projects is whether transmission infrastructure will be built in a timely manner to enable electricity to be transported to consumers. New generation projects can often be developed in as little as half the time it takes to build new transmission lines.

Accordingly, transmission investment should be considered as an enabler of least-cost electricity generation. Parties developing the transmission investment process should consider how efficient transmission investments can be implemented ahead of certainty over generation developments.

5. A carbon regime enables more renewables generation.

Figure 5 shows the impact of pricing the carbon emissions created from thermal generation, with the cost of thermal generation plant increasing against other options. The effect on the LRMCs of thermal projects under the two carbon scenarios analysed is summarised in Table 2.

A carbon charge increases the cost of thermal generation, with the size of the increase related to the efficiency of an individual station and the characteristics of the fuel consumed.

As Figure 5 shows, the carbon charge results in more renewables projects becoming economic relative to thermal alternatives. This is not to say that no renewables projects would be built if a charge was not introduced. The figure highlights that prime renewables should be economic even if there is no carbon regime. However, the number of "prime" renewable projects is small; there are only a handful of such projects in New Zealand. A carbon regime would enable the middle tier of renewables projects to be economic. There is a far larger number of generation projects in this category.

6. Under an LNG option, only existing gas-fired plant would be economically viable.

It is expected that LNG imported into New Zealand would cost more than $9/GJ. As LNG prices are indirectly indexed to oil prices and world energy demand is growing rapidly, it is possible that the LNG price could be substantially higher than this figure. Figure 5 shows that at this level of price, new gas-fired generation stations would not be economic, especially under a carbon regime.

TABLE 2:	IMPACT OF CARBON CHARGE ON COAL AND GAS-FIRED GENERATION			
	$15/t CO_2e carbon price		$25 /t CO_2e carbon price	
	ΔLRMC	Adj. LRMC	ΔLRMC	Adj. LRMC
Coal	$13–16/MWh	$88–118/MWh	$23–27/MWh	$99–128/MWh
Gas	$6 /MWh	$58–116/MWh	$10/MWh	$62–126/MWh

Gas price range is $4-12/GJ

Existing gas-fired plant would be economic, as their capital costs are sunk. However, the change in cost structure of this plant would mean they may have to operate differently, possibly as mid-merit plant. It is also possible that the rigid take-or-pay price structure common in LNG supply contracts could distort plant behaviour.

A decision to import LNG would radically alter New Zealand's electricity generation sector. The whole industry would be linked to international energy patterns given the role of gas-fired generation in the sector. The long length of LNG contracts, typically 20 years or more, means there would be little ability to "opt out" of such an arrangement if New Zealand's fuel situation changed – for example if there was a major domestic gas discovery during this time.

7.4 Other Factors Affecting New Generation Options

The previous discussion compared the relative economics of generation options as a key factor influencing the future generation mix. Other factors are also important in project selection. For instance, a project will not proceed unless the site is secured, technical feasibility has been completed, the proposed development is consented and plant items and works have been tendered.

There are two key factors that greatly impact on the timing and viability of projects:

- Land access. Many generation opportunities require access to or use of land belonging to landowners or used by leaseholders who are not necessarily the developer. The land may be required to site plant or other infrastructure. This infrastructure may include transmission lines, canals, or gas pipelines. Land may be required to provide access to the power station, or be affected as part of a hydro development. Depending on the number of parties that are affected and the nature of their existing land use, the process of negotiating the sale of land or obtaining easements can be protracted and costly, perhaps even impossible.
- Resource consents. Obtaining the right to develop a site for generation under the Resource Management Act is a significant hurdle that must be faced by all projects. Every type of generation and individual project will have its own environmental issues that need to be addressed as part of this process. For instance, some generation types will be a permitted activity in some authorities and prohibited in others. Sometimes a district plan change is required before a resource consent can be lodged. Outcomes from the resource consent process are uncertain.

The delays, commercial arrangements and imposed conditions that stem from the above two processes can change a project's economics considerably or even prevent a project from going ahead.

7.5 Summary

In general, the economic variation among various projects of the same generation technology (whether this is coal, gas or renewable generation) is greater than the variation among technologies. From an economic perspective, New Zealand's future electricity production is likely to come from a range of generation plant.

The share that each generation type will have depends on a number of factors. In particular, if significant amounts of low-cost indigenous gas are found, for example another Maui sized field is discovered, then there will be a greater proportion of new generation that is gas-fired with some renewable generation.

Under other gas scenarios, renewable generation will form a significant part of total new generation capacity and production. In these scenarios, the best new generation projects will be wind farms in "prime" locations, hydro generation in "prime" locations and geothermal expansion projects. These projects have the advantage of being environmentally sustainable.

However, there are only a small number of wind and hydro projects that fit into this "prime" category. Many are defined as projects in "good" locations. Depending on the nature of the gas environment, which will affect the price of wholesale gas, incentives may be required for these projects to be viable economically. A policy environment where the cost of carbon is properly reflected is one important avenue for encouraging these projects.

Although the cost of various generation project options is a key factor in determining project selection, there are also other important considerations. The ability of a generation company to gain access to land and to obtain appropriate resource consents is a critical factor that affects the viability of a project.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8.0

Part B – Review of Options Introduction

The focus of this part of "Choices" is to provide details on the generation and demand side options discussed in Part A. In each of the sections that follow, we examine the economic characteristics of the various options. Issues that impact on each option are also considered.

The wind and hydro sections that follow are based on Meridian Energy's experience in developing and operating these projects. Project cost ranges have been driven off actual project investigations. The issues that have been identified also stem from Meridian Energy's practical experience.

As a participant in New Zealand's wholesale electricity sector, Meridian Energy also has an in-depth knowledge of other generation forms. Meridian Energy has reviewed a number of specific projects to a pre-feasibility stage for other generation technologies, such as coal and geothermal, to understand the project cost dynamics involved.

As described in Part A, the economics of gas-fired generation hinges on the availability and price of indigenous gas. Capital costs form a smaller component of the long run marginal cost (LRMC). Given this, the gas generation discussion concentrates on fuel availability as a major theme.

In New Zealand, other generation such as micro-generation currently forms a second tier below the generation forms discussed above. In the following sections we present a desktop evaluation of these options.

To date, demand side options including energy efficiency and micro-generation initiatives, have played a relatively small role in New Zealand's electricity sector. This is not surprising given the low price of wholesale electricity relative to many other countries. These options are expected to gain more prominence in New Zealand's electricity industry as technologies improve and the cost of electricity supply increases over time.

This part of the report includes a high level summary of demand side issues.

Our evaluation has been based on conventional, proven technologies. There are two reasons for this. First, it is likely that the options considered will be the dominant economic options for at least the next 20 years. Related to this, is the fact that it takes some time for new technology to bed down. To keep this report grounded, we have avoided speculation on new technology forms.

For similar reasons, we have adopted current cost structures of various options in providing a window into the future wholesale electricity sector. Some work of this type assumes a steady reduction in costs as technology improves or becomes widespread. It is true that the cost of embryonic technology does follow a downtrend trend as the technology matures. However, the rate of decline is uncertain and forecasting the decline is speculative. In addition, we have seen cost increases in some technologies in recent times. For example, wind and gas generation costs have increased. An assumption of ongoing cost reduction is not always valid. We have avoided making speculative assumptions by keeping the discussion based on known information.

A 9 percent post-tax nominal discount rate has been used throughout the report.

9.0
Hydro Power

Hydroelectric generation is New Zealand's largest electricity source, providing low-cost, flexible and sustainable electricity. There remain economically viable opportunities to grow hydro power in the future without compromising environmental, social and community outcomes.

9.1 Introduction

Hydro power has been instrumental in the growth and development of many nations during the 20th and 21st centuries, including Canada, USA, Norway, Japan and New Zealand. In the early part of last century, development was viewed as being for the greater good of the country and this has left a legacy of hydro generation for future generations. This cycle is continuing today, with a number of developing countries, such as in Bhutan, building medium to large hydro schemes.

New Zealand's first public hydroelectric power station commenced operation in 1887. It turned on the first public electric lighting in Reefton, a small mining town on the West Coast. For the next 25 years, a number of small hydro power stations were built around the country in conjunction with the first electricity distribution networks.

In 1914, the first of the larger hydro power stations, Coleridge, was built and for the next 80 years large hydro power stations were built at regular intervals to keep up with growing demand. Large scale hydro power construction peaked in the 1960s and 70s and culminated with the Clyde Dam, commissioned in 1993. Small hydro development also continued over the same period, peaking in the 1980s.

The most significant hydro development in the last 10 years has been the drilling of the second tailrace tunnel at Manapouri followed by the station refurbishment, which together added 250 MW generation capacity and an annual average of 800 GWh to the station[2]. During this period a number of small hydro power stations have also been built, and several of the older large hydro stations have been refurbished.

9.2 The Role of Hydroelectric Generation

Over the past century, hydro generation has been the predominant power source for New Zealand's electricity needs. However, since 1994 it has gone from being approximately 75 percent of the country's total generation to an average of about 60 percent. Gas-fired power stations have been the predominant generation built since the mid 90s to meet growing demand.

There is good synergy between hydro energy and other existing and potential future sources of renewable energy. The output from a number of forms of renewable energy (such as wind or, in the future, solar, wave and tidal currents) is somewhat variable given the changing nature of the associated natural resources. A feature of hydro generation is its flexible operation. Electricity production can be ramped up and down rapidly in response to the changes in output and load from these other sources of renewable energy.

[2] Note: The ability to use the additional capacity of Manapouri above 710 MW and capture about 100 GWh pa of spill is dependent on a change in resource consents for the scheme.

About 70 percent of New Zealand's hydro power is located in the South Island. The South Island has an annual average production of 17,700 GWh. The North Island contributes a further 7,000 GWh of annual average production. Hydrology can fluctuate significantly year on year, resulting in hydro generation varying by up to 2,500 GWh per annum, with subsequent positive or negative effects on wholesale market prices.

In 2001, Meridian Energy announced Project Aqua, a proposed 540 MW six-station canal scheme on the Lower Waitaki. Nearly three years later the project was cancelled. While some commentators regarded this as the end of new hydro development in New Zealand, a number of small to large hydro schemes have been progressing their way through the development process since then.

In 2004, East Harbour (East Harbour Management Services, 2004) identified 11,700 GWh of viable[3] hydro opportunities. However, this report included the 3,000 GWh Project Aqua which has subsequently been replaced by a different, smaller project referred to as the North Bank Tunnel concept. Revising East Harbour's figures with this and a smaller Dobson scheme gives 9,800 GWh of hydro potential. A more recent study by East Harbour for EECA (East Harbour Management Services, 2005a) estimated around 755 MW and 4,260 GWh of hydro potential at moderate to high confidence levels at estimated costs of up to 10c/kWh – the remainder of the hydro potential is at lower confidence levels.

Table 3 shows the publicly known hydro developments that are progressing through various stages of development – about a third of the above potential. The other two-thirds are made up of many small schemes, plus a few medium-large schemes on the Lower Clutha, Grey and Waiau Rivers.

9.3 Issues

As discussed, there remain a number of economically viable hydroelectric projects. The development of these projects depends on a number of factors. In more recent times, stakeholder issues have risen in prominence. This set of issues, as well as several other issues affecting hydro projects, is identified below.

Stakeholder Issues

There is a range of stakeholder groups that need to be consulted with and whose issues need to be addressed when considering a hydro development on a river. Potential issues may include the effect of changes in river flows or levels on recreational or business activities, cultural values, and social and environmental impacts. Major stakeholder groups include:

- Local communities and councils. Local communities may be significantly affected by a hydro development. There may also be a perception that local resources are being used for the benefit of cities.
- Iwi. Local iwi will normally have a historical connection to a river, as a source of food, healing, trade and travel. For this reason rivers may be seen as taonga (treasure), mauri (life force) and tupuna (ancestor).
- Irrigators. Existing irrigators will generally have abstractive rights and will want to ensure that the reliability of their water take is not diminished.
- Environmental groups. Groups such as Royal Forest and Bird and Greenpeace will particularly be concerned about the effect of the development on local flora and fauna and what mitigation measures will be undertaken.
- Recreational river users.

Environmental Issues

Significant environmental studies need to be undertaken to determine the effects of a proposed hydro development on local ecosystems. Measures also need to be identified to mitigate these effects. Specific issues are scheme dependent and may include the following:

- effect on migration of fish, eels, whitebait
- effect on local flora and fauna
- potential for stratification[4]
- potential for gravel/sediment build-up
- impact of weeds and algae
- visual impact.

A number of rivers are protected by Water Conservation Orders or exist within National Parks. The latter are typically excluded for development of hydro power.

Land Issues

Most hydro schemes will need to involve landowners or leaseholders who are not necessarily the developer. Land may be flooded, required for site access or crossed by infrastructure. Affected parties can include local communities, farmers, the Crown, leaseholders and local iwi. A developer needs to purchase the land or negotiate easements with affected landowners and leaseholders.

Depending on the number and type of parties and the issues associated with a project, these issues may be sufficient to cause the project to be terminated. At a minimum, resolving land issues may be a protracted process.

Engineering Issues

Every prospective hydro generation site is unique. River flow, including volume and variability, surrounding topology, fauna and flora, underlying geology and gravitational potential all vary. For this reason, hydroelectric generation is not "off the shelf" and each site will likely require a unique configuration to harness the water's energy economically while minimising adverse environmental effects.

Some schemes involve building a dam across a river to create a storage lake. This gives a height differential that is used to create energy potential; water is passed through penstocks to a power station at the bottom of the dam to generate electricity. Other schemes divert water out of the main stem of a river or from a reservoir. The water is diverted through a series of tunnels, canals or penstocks to a power station. The power station releases the water back into

[3] The figures excluded opportunities that were on protected rivers or where costs for development were greater than 15c/kWh

[4] This is a layering effect where deeper water in a reservoir becomes colder than the surface and can contain reduced oxygen levels, which may cause the decline of downstream habitats.

FIG 6: **HYDROELECTRIC GENERATION IN NEW ZEALAND, 1900 – 2005**

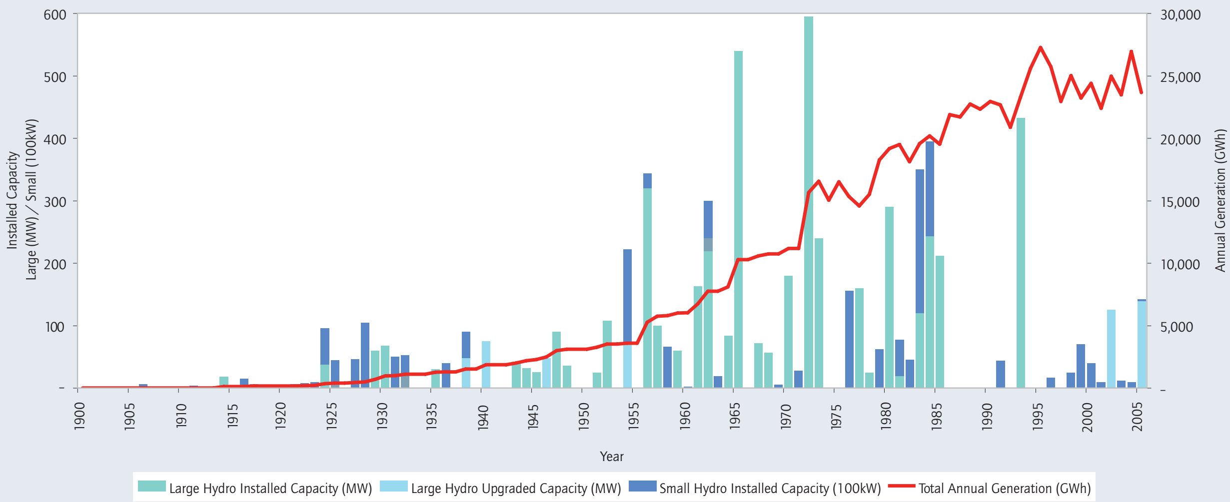


Table Note: Small hydro is displayed on a different scale from large hydro

TABLE 3: **POTENTIAL HYDRO DEVELOPMENT IN NEW ZEALAND**

Region	Company	Project	Capacity (MW)	Ave Annual GWh	Stage
North Island	Meridian Energy	Mohaka	40-70	200-330	Investigations
	Esk Hydro Power	Toronui Mini Hydro	1.0	4.3	Investigations
	King Country Energy	Mokau	9.6	44	Consent declined
	Bay of Plenty Electricity	Upper Kaituna	14	60	DOC concession declined
	North Island total		**65-95**	**310-440**	
South Island	Meridian Energy	North Bank Tunnel	210-280	1,200-1,400	Consultation
	Contact Energy	Hawea Gates	17	70	Consenting
	Kawatiri Energy	Lake Rochfort	4	16	DOC concession
	Pioneer Generation	Nevis	45	197	Investigations
	Majac Trust	Gowan	14	60	Appealing Buller Water Conservation Order in Env. Court
	Meridian Energy	Mokihinui	40-70	200-300	Investigations
	TrustPower	Coleridge upgrade	8.5	95	Currently being upgraded
	TrustPower	Wairau HEPS	70	415	Consent Hearings
	TrustPower	Dobson	46	216	Consent application lodged
	TrustPower	Waipori Deep Stream	5	22	Progressing – due Oct 2007
	TrustPower	Rangitata Diversion	6	26	Investigations
	Meridian Energy	Manapouri Refurb.	140	102	Progressing – due Oct 2007[5]
	South Island total		**605-705**	**2,620-2,920**	
Total NZ			**670-800**	**2,930-3,360**	

the river further downstream or in some cases to another nearby river at a lower altitude.

Transmission Issues

- Constraints. Some of the large hydro opportunities in the lower South Island would require a significant upgrade of the core transmission grid. The cost of these upgrades may be too great for a single project to bear.
- Distance. Opportunities may be some distance from a transmission or distribution line of sufficient capacity to connect into. The difficulties and costs associated with securing easements with landowners for a long route can add considerable uncertainty and delay to a development.
- HVDC pricing. Most of the remaining hydro opportunities are located in the South Island and are therefore subject to HVDC charges. As shown in the Economics section below, this adds a significant cost to new hydro developments.

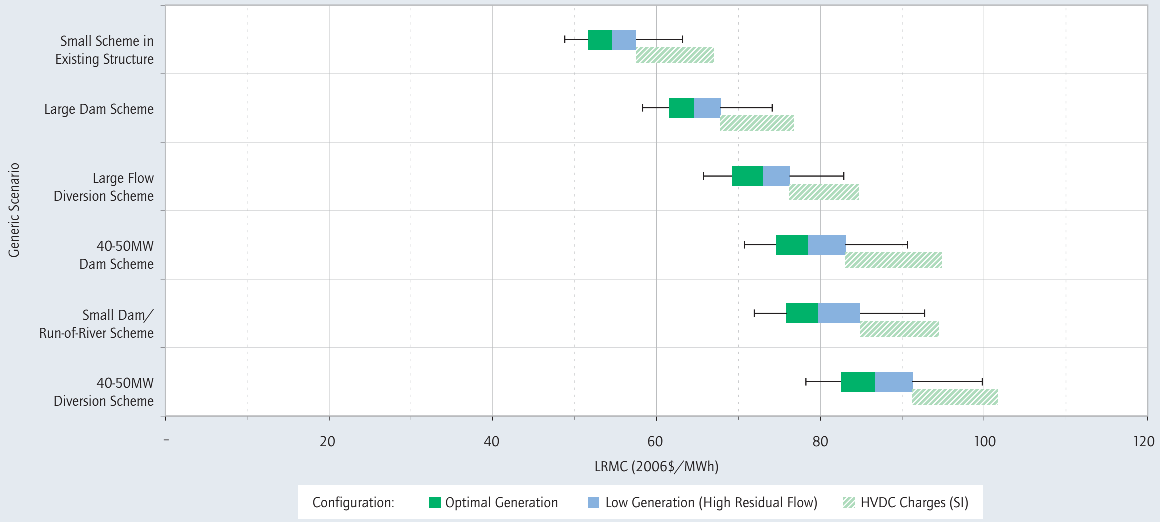
9.4 Economics

Broad Economic Drivers

The economics of particular hydroelectric generation projects hinge on a variety of

[5] Requires increased discharge consent to fully utilise additional capacity for capturing spill.

FIG 7: LONG RUN MARGINAL COSTS FOR SELECTED HYDROELECTRIC POWER STATIONS



factors, including those discussed above. There are two key factors:

- Hydro resource. The nature of the resource, including how much water can be stored and inflow variability, will impact directly on potential generation from a scheme. An advantage of hydro is that these factors are known in advance from historical records, and the scheme can be designed to best utilise the resource.
- Capital cost. A significant driver of hydro development costs is the civil component. Civil works include the amount of earth to be moved, concrete to be laid or length of tunnels to be bored. Imported components such as turbines, generators and electrical equipment make up a relatively small part of overall cost. This means hydro developments are less exposed to changes in exchange rates than some other generation technologies.

Project-specific Evaluation

The LRMC of a range of hydro developments has been determined from publicly available cost and generation information for schemes that are currently under consideration or listed in the East Harbour reports. Where no public information is available on a scheme, we have used historic ECNZ reports and brought costs up to date. The LRMC results have been grouped into a number of generic configurations, which include:

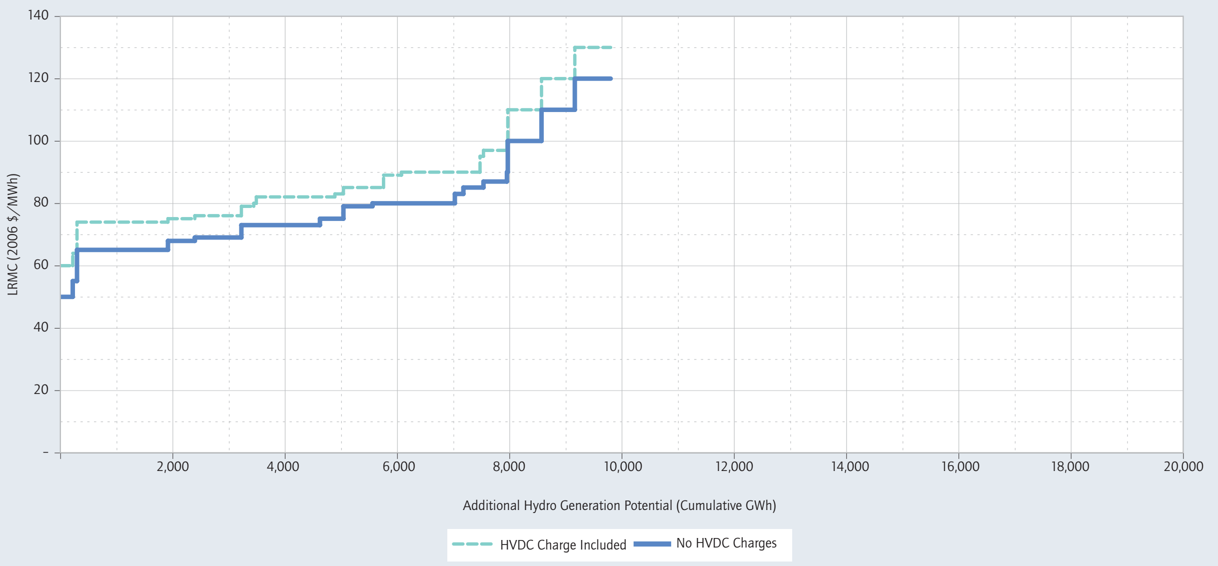
- Small scheme in existing structure. This involves capturing the energy normally dissipated through an existing control gate by adding a small turbine. Examples of this include Contact Energy's Hawea Gates scheme.
- Large dam scheme. A dam with an 80-250 MW powerhouse scheme. This is based on several historical ECNZ schemes studied on the Upper and Lower Clutha River, including Luggate, Queensberry[6] and Tuapeka.
- Large flow diversion scheme. This involves diverting flow from a river into a canal or tunnel to feed a single large or series of small to medium-sized power stations.
- 40-50 MW dam scheme. This involves damming the course of the river. It assumes the power station is integral to the dam and that all water, except for floods, can be captured.
- 40-50 MW diversion scheme. This involves damming the course of a river and using it as a head pond to feed canals or tunnels to the power station further downstream. It involves higher civil costs and requires a residual flow through the dam that may not be captured for power generation.
- Small dam/run-of-river. A scheme under 20 MW. The scheme can generate either through a dammed river with a power station, or by diverting flow through a tunnel to a downstream power station.

The results of the scenario analysis are shown in Figure 7. The coloured bars give an indication of how LRMC can vary depending on the power station configuration for a given head and flow. For example, variables can include different dam locations, heights, size and number of turbines. In the case of a flow diversion scheme a higher LRMC might be driven by the need to maintain a higher residual flow in the river.

The striped bars indicate the incremental effect that the current HVDC pricing regime adds to the LRMC of a new hydro power station in the South Island. The size of the impact depends on the cost and allocation of the proposed HVDC grid upgrade – the models assume a near doubling in HVDC costs by 2012.

6 Technically Queensberry is a large-flow diversion scheme but its LRMC fits into this range.

FIG 8: LRMC CURVE FOR HYDRO POTENTIAL IN NEW ZEALAND



The lines on either side of each bar provide a sensitivity on capital costs – the coloured bands slide along these lines depending on the difficulty of the site in relation to the base case.

In Figure 7 the high side (right-hand side) of the sensitivity lines represents a 10 percent increase in overall capital costs (note that for cost estimates at a feasibility level of analysis, a rule-of-thumb is that costs might vary by up to 30 percent) – for example from greater civil/geotechnical difficulty, a longer transmission route or a higher voltage connection.

The low side (left hand side) of the sensitivity lines represents a 5 percent decrease in overall capital costs – for example from lower turbine prices, an easier site, onsite transmission or an increase in the New Zealand dollar.

Implications

New Zealand still has a number of economic medium and large hydro sites that can potentially be developed. Any site development will be dependent on an economic validation following further investigation. Important considerations also include the risk appetite of a potential developer, the environmental impact of a potential scheme and acceptance of the scheme by the stakeholder community.

Smaller sites may have higher LRMCs due to diseconomies of scale. However, even with a higher LRMC they may still be economic if the scheme is in a transmission constrained area, such as the Upper South Island, or in a remote area with high nodal prices, such as the West Coast.

A factor that is not captured in the LRMCs in Figure 7 is the flexibility and fast response of hydro generation. With adequate storage, a hydro power station can be operated to provide power during peak demand periods, or operated to balance variable demand or other intermittent power sources. One of the key enablers for increasing the penetration of intermittent generation in New Zealand will be its flexible hydro generation base.

LRMC Curve

Figure 8 gives an indication of the LRMC cost-curve of hydro generation opportunities in New Zealand. This is based on a point estimate of LRMC for individual sites taking into account the factors discussed above. The difference between the two curves is the maximum expected impact of HVDC charges on South Island opportunities.

It should be noted that the points on the curve are based on a high level, best estimate of the likely degree of difficulty of various projects. Each segment on the curve should be considered as an approximate mid point of a range that could vary by as much as the LRMC ranges shown in Figure 7. For hydro projects that are at a desktop study level, the variation could be as much as 30 percent, due to the significant number of uncertainties that need to be resolved.

10.0
Gas

The Maui gas field has been a large source of low-cost energy over more than two decades. Modern combined cycle gas turbines fuelled by this gas have kept electricity prices low. With the decline in Maui reserves, future gas availability has become uncertain and gas prices have risen. CCGT plant may no longer be the most economic new generation option.

10.1 Introduction

Thermal[7] generation plant has an important role in New Zealand's electricity sector. Thermal plant balances the inherent variability of hydro generation caused by the unpredictable nature of weather events. In addition, because thermal fuel can be transported there is also some limited ability to locate thermal plant closer to demand. This is dependent partly on availability of infrastructure to transport the fuel.

Gas-fired generation has been the thermal fuel of choice for more than two decades because of the comparatively low price of gas and its lower emission profile relative to coal. Gas has traditionally been the primary fuel of the 1,000 MW Huntly Power Station. Huntly is a dual-fired plant, able to operate on both coal and gas. Gas has also fuelled Contact Energy's New Plymouth Power Station, a 300 MW steam turbine plant, which is relatively close to retirement and is mainly used for reserve generation. Smaller volumes of gas are still used in both these plants.

Gas is used to fuel Contact Energy's 367 MW Taranaki Combined Cycle (TCC) plant and its 380 MW Otahuhu B combined cycle gas turbine (CCGT) plant. It is also used in a range of smaller generation plants, including cogeneration facilities. Genesis Energy is currently building e3p, another CCGT plant, located adjacent to its Huntly Power Station. Other plants have been proposed at various times, although development of most of these is on hold because of New Zealand's relatively tight gas supply situation.

As discussed in Part A, New Zealand's future wholesale electricity price tends to be shaped by the economics of new gas-fired generation. Theses economics are driven predominantly by the wholesale price of gas. In turn, this price is driven significantly by the amount of indigenous gas reserves. Given the importance of domestic gas availability, the discussion in this section focuses initially on New Zealand's gas resource. This is followed by a review of the economics and issues surrounding new CCGT plant.

10.2 Gas Availability

Background

New Zealand's gas industry has been dominated by the Maui field, which began production in 1979. At the time Maui was discovered in 1969, it was one of the largest gas discoveries in the world. In contrast, New Zealand's demand for gas in the late sixties was limited largely to reticulated domestic consumers. With the discovery of the Maui field, New Zealand's gas supply substantially

[7] Plant fuelled by non-renewable, carbon-based fuels – including coal, gas (predominantly methane and ethane, specified by the standard NZS 5442) and oil.

exceeded demand, although several "Think Big" projects were developed to harness some of this newly discovered fuel. Given these market conditions, the Maui Gas Contract between the Crown and the Maui Mining Companies was struck with what has turned out to be a relatively low price. This price has set the wholesale gas market price.

This low gas price has benefited a range of New Zealand industries. Notably, Methanex has used significant volumes of gas in the production of methanol. Gas is used in industries ranging from fertiliser production to the dairy industry. The low price has also led to relatively low electricity prices by world standards. The delivery flexibility provided by the Maui gas field has also been used to offset hydrology variability in the electricity industry.

The dominance of the Maui field and this low price has also contributed to relatively low levels of petroleum, including gas, exploration in New Zealand over a number of years. An example of this limited activity is the Kupe field. This field was discovered in 1986, but until recently it has been uneconomic to develop at the prevailing market price.

New Zealand's wholesale gas market was turned on its head in 2003, when an Independent Expert concluded that the remaining gas reserves in the Maui field were significantly less than previously thought. Downstream gas users' remaining gas allocations were scaled back and they adjusted their operations. In the electricity sector, Contact Energy and Genesis Energy had to alter their operation of thermal plant. In particular, Genesis Energy switched its Huntly Power Station to run mainly on coal. Lead times in coal supply, coupled with a moderately dry year, led to a period of tight electricity supply in 2003.

New Zealand's gas industry remains in a period of flux, with gas supply remaining tight. It is expected that in the future, supply will come from a number of smaller fields. Gas wholesale prices have already adjusted to these changed market conditions. The economics of gas-fired electricity generation are directly affected by this change in fuel prices.

The Gas Supply Situation

As noted above, New Zealand's wholesale gas market has tightened considerably over the last few years. The re-determination of the Maui gas field has initiated a period of tight supply, although arguably the situation was on the horizon for several years prior to this event.

It is estimated by various parties that gas supply will fall below current levels of demand sometime in the middle of the next decade unless significant new gas discoveries are made. The Ministry of Economic Development (MED) has estimated that this date could be around 2015 (Minister of Energy, 2004) although some other parties are less optimistic. Methanex has already reduced its production significantly.

New Fields

New Zealand is known to be a relatively prospective petroleum (including oil and gas) destination. Various new gas fields are expected to enter into production in the next several years. The Pohokura field[8] has recently entered production. The Kupe partners have recently made their financial investment decision on the Kupe field and it is expected to enter into production in 2009[9]. Maui ROFR gas ("right of first refusal" gas) has been estimated at this stage to have median confidence reserves of around 200 PJ. ROFR gas is separate from the gas included in the Maui Gas Contract. However, the approximate size of these reserves has been known for several years.

Petroleum Exploration

The petroleum industry has responded to these changed market conditions. Exploration activity has increased markedly over the last two years or so. The New Zealand government has provided a package of initiatives (Minister of Energy, 2004) designed to increase the level of exploration in the short to medium term. However, this exploration activity has been hampered by limited offshore oil rig availability and increases in price driven by the hurricanes in the Gulf of Mexico in 2005.

There were 34 petroleum wells drilled in 2005, compared with 26 in 2004 and 11 in 1999. However, all of the wells drilled in 2005 were onshore (although Pohokura wells were deviated off-shore). Onshore wells are significantly cheaper than offshore wells, and the rigs are more readily available. However, the size of onshore discoveries is likely to be an order of magnitude smaller than offshore discoveries. Accordingly, onshore exploration activity, while yielding useful quantities of gas, is unlikely to materially alter the tight nature of the New Zealand wholesale gas situation.

Three petroleum exploration blocks are being offered by Crown Minerals in 2006: Offshore East Coast, Offshore Taranaki-Wanganui and the Great Southern Basin. Crown Minerals has awarded four exploration permits from the first two blocks offers, though another four exploration permits have been issued outside the bidding round. This level of activity is less than anticipated, especially in the East Coast basin where the Crown had conducted its own seismic exploration to encourage interest from explorers. The Great South Basin, with about 400,000 square kilometres of acreage, has recently been offered. The prospectivity of this basin has been hyped up by various parties though the reality is that this is a frontier region and its potential resource is unknown.

New Petroleum Discoveries

Despite the increased levels of exploration activity over the last several years, new petroleum discoveries, to date, have been relatively limited. Discoveries made over the last year or so include:

- Piakau North – a small on-shore Taranaki gas-dominated discovery.
- Supplejack – a small on-shore Taranaki gas discovery.

8 Fiftieth percentile (P50) median confidence gas reserves estimated to be 700 PJ.
9 P50 gas reserves estimated to be 253 PJ.

- Cardiff – an on-shore Taranaki gas discovery. Appraisal of this field has been beset with difficulties and its level of reserves and economic viability are unclear.
- Cheal – a small on-shore Taranaki oil discovery with no commercial levels of gas.
- Turangi – an on-shore Taranaki gas/condensate discovery. Median confidence gas reserves have been estimated at 154 PJ.

In addition, Todd Energy announced its discovery of the Karewa field at the 2004 Petroleum Conference. Reserves of 50-150 PJ were mentioned, but limited details have been provided since then.

While this success ratio is relatively high at around 10 percent, the volume of gas found, to date, has been modest. These discoveries do not replace current gas consumption levels of around 150 PJ per annum as noted in the Energy Data File (Ministry of Economic Development, 2006) for the year ended September 2005.

With a projected gas supply "shortfall" date of 2015, time is running out for indigenous gas reserves to be found. The lead times in the petroleum exploration and production (E&P) industry are relatively long. In a brief to infrastructure Ministers the MED noted (Ministry of Economic Development, 2004) that onshore petroleum prospects "could take 2-3 years, or as long as 8-10 years for exploration and appraisal. They could take a further 1-4 years to develop". For offshore prospects "... the exploration phase could take 5-10 years... The development phase could take 5-10 years". However, these timeframes could potentially be reduced given appropriate market conditions.

It is important to stress here that it is not a question of whether sufficient recoverable indigenous gas reserves are present; as stated earlier, New Zealand is considered relatively prospective and gas is out there (somewhere). Rather, the issue is whether sufficient new reserves can be found in timeframes so that forecast gas demand levels can be met. This is particularly an issue for the electricity sector, which is currently the largest consumer of gas.

LNG

Recognising the potential for a gas shortfall in the next decade, Genesis Energy and Contact Energy commissioned a feasibility study in 2003 to understand the potential for importing LNG (liquefied natural gas) as an alternative to indigenous gas. These companies have recently announced that Port Taranaki will be the site for a possible re-gasification/storage facility. This site decision enables the companies to retain LNG as a real option, given the lead times in obtaining resource consents and building LNG infrastructure.

The issues around importing LNG are significant and the decision to proceed down this route will need to be taken extremely carefully. The implications of LNG-fuelled electricity generation are discussed later in this section. Issues specific to the LNG sector include:

- LNG contracts are typically benchmarked to oil or gas markets. With the convergence of world LNG markets, the price of LNG will tend to vary with oil price movements. Given the escalating demand for energy from developing countries such as China and India there is likely to be upward pressure on LNG prices. Depending on various factors the price of LNG could easily be more than $9/GJ delivered to New Zealand.
- LNG contracts are generally rigid, due to the large fixed capital costs that exist throughout the industry. Spot trades are infrequent. Contract terms as long as 20-25 years are not uncommon and there are typically restrictions on on-selling LNG shipments. A long-term LNG contract would appear to be at odds with the potential gas shortfall issue in New Zealand, which is a short-term supply issue.
- With the increase in energy demand worldwide, the demand for LNG has increased significantly. A year or two ago, it was expected that there could be a short-medium term over-supply of LNG, with a number of new LNG projects coming on-stream. This situation has changed rapidly, to the extent that a supply shortfall potentially exists. This changing situation puts pressure on the terms of any LNG contract.
- New Zealand's demand for LNG would be small scale. Contact Energy has said that initial demand could be in the range of 50-60 PJ per year. This volume is minimum scale in the LNG industry. Given the increased demand worldwide for LNG, New Zealand could simply be too small to exert any influence and exposed to the vagaries of the market.

If LNG was imported into New Zealand at the 50-60 PJ per annum scale suggested, this would be a significant portion of total domestic gas supply – especially given that demand would reduce with high wholesale gas prices. Given a long, rigid LNG supply contract, the importer would need to ensure that demand was contracted in such a way that commercial risk was minimised. For instance, the risk of a significant indigenous gas find would need to be addressed. It is possible that the Crown could be asked to help offset this risk; the MED recognised this issue in its 2005 Brief to Incoming Ministers (Ministry of Economic Development, 2005). It has played an analogous role in the Maui Gas Contract as the Buyer of Maui gas, sitting between the Seller and downstream users. The risks of being the "buyer" of LNG over an extended period are likely to be significantly greater.

CNG

Partners in the Papua New Guinea (PNG) gas project, known as the PNG Project, have approached several New Zealand companies regarding the possible importation of CNG (compressed natural gas) as an alternative to LNG. The option under review includes the following elements:

- Production of gas in PNG and transport via transmission pipelines to Queensland – the "PNG Project". Amongst other things, this involves the construction of a 3,000km pipeline from PNG to Queensland so that PNG's gas can be supplied into Australia. The final investment decision was expected this year, although the project is appearing less likely with reports of significant increases in estimated capital costs. An alternative option, where CNG would be shipped directly from PNG to New Zealand, has been mentioned.

- Shipment of CNG from Gladstone, Queensland to New Zealand, or possibly directly from PNG. In contrast with LNG, CNG shipping costs on a per volume basis are significantly greater – the volume of CNG is much larger than LNG on an energy basis. Large-scale CNG ships that would be used over such distances are a new technology. For instance, EnerSea Transport completed the prototype testing of its VOTRANS CNG shipping system in late 2005.

  Though the transport technology is very new, CNG could possibly have a cost advantage over LNG. The contractual arrangements for CNG may also be less rigid. Contact Energy has said that importation of CNG by ship is becoming a more realistic option.

10.3 Combined Cycle Gas Turbines

Most new gas generation plant tends to use combined cycle technology because of its relatively high generation efficiency and superior economics. However, open cycle gas turbines (OCGTs) are also built to operate as peaking or reserve plant. These have the advantage of lower capital costs but higher operating costs. Examples of OCGTs in New Zealand include Genesis Energy's 48 MW Huntly OCGT and the Crown's 155 MW Whirinaki OCGT, which is operated as a reserve plant. In this report, we focus on the economics of new CCGT plant.

A CCGT power plant consists of one or more gas turbine generators combined with a heat-recovery system used to power an auxiliary steam turbine. This combination of gas and steam turbines allows for thermal generation efficiencies of around 50 percent. This compares favourably with conventional coal generation at approximately 35 percent efficiency. Gas turbines can run on either natural gas or liquid fuels – typically distillate. Gas is the usual preferred choice of fuel due to cost, flexibility and lower emissions.

The Role of CCGT Generation in New Zealand

In New Zealand three CCGT plants, at Southdown, Taranaki and Otahuhu have been constructed through the late 1990s; totalling some 900 MW of installed capacity. Further CCGTs have been planned, but these plans have been hampered by New Zealand's tight gas supply situation.

CCGTs currently under investigation include:

- The 385 MW Huntly e3p CCGT project is currently under construction and due for commissioning in early 2007. However, Genesis Energy has required a government guarantee to proceed with this project.
- An additional 45 MW gas turbine has been installed at the existing Southdown site and will be commissioned by the end of 2006. However, this is likely to be run in a peaking, open cycle configuration.
- Consents exist for Contact Energy to build further CCGT plants alongside Otahuhu B and TCC. These projects have been put on hold until gas supplies are secured.
- Genesis Energy is investigating the option of a modular 240-360 MW CCGT plant in the Rodney district. Consents are being sought for this project. However, it is unclear if enough gas can be sourced to make the project economic.

In contrast to more typical CCGT operation in other countries, the CCGT plants in New Zealand have historically been run in a simulated base-load fashion with average load factors of around 70 percent. This compares with industry life-cycle averages of 90 percent or higher. The significant flexibility of the Maui gas field has allowed the plant to respond to hydrologically linked electricity market conditions and reduce output when surplus water is available. This level of operational flexibility is less likely in the future as Maui gas is replaced by gas from multiple, smaller gas fields or possibly either LNG or CNG.

10.4 Issues

As discussed, gas price and availability are the most important factors affecting CCGT economics. Other factors that affect the LRMC of these plants include location and environment issues. These factors are discussed below.

Gas Price

Gas prices in New Zealand over the last two decades have been set by the Maui gas price. This price has been comparatively low at around $2-3/GJ, indexed against price movements. In recent years, as the Maui Gas Contract's remaining gas reserves have reduced, wholesale gas prices have increased reflecting market conditions.

There is a general lack of transparency in wholesale gas prices in New Zealand with the vast bulk of gas sales occurring through bilateral contracts. Industry consensus appears to have gas currently priced at around $6-7/GJ. Where this price will trend to in the future is uncertain; it will largely be determined by the nature of future gas discoveries. If gas supplies remain tight, prices will at least remain at current levels. If LNG or CNG is imported, wholesale gas prices will be considerably higher again.

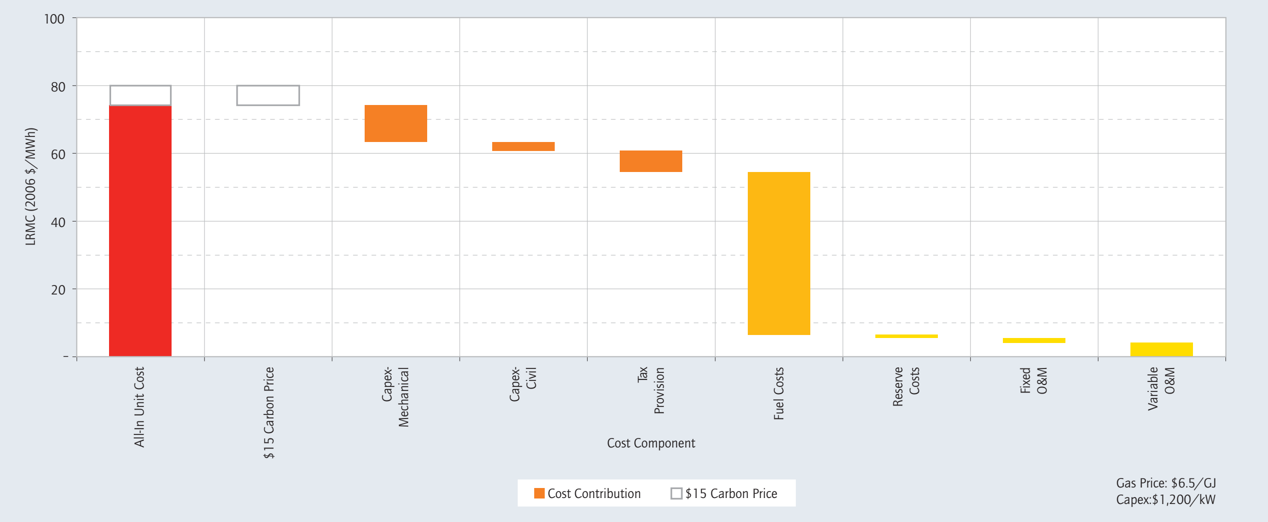
The implications of gas price on the LRMC of new CCGT plant is discussed in the following section.

Location Issues

The location of a CCGT gas plant impacts on its feasibility and broad economics – but less so than for other generation types such as coal, hydro, wind or geothermal. The location factors include the following:

- Proximity to gas supplies and gas transportation. A CCGT plant needs to be located either close to a sizeable gas field with reserves sufficient for the life of the asset, some 25-30 years, or close to a major gas pipeline that can deliver gas from multiple sources. Natural gas is transported in pipelines that are both

FIG 9: CCGT LRMC COMPONENTS



expensive to build and have significant operational costs. In the New Zealand context this means that large CCGT plants are unlikely outside of either Taranaki or along the path of the Maui and major Vector pipelines – which trace a path from Taranaki, past Huntly Power Station, and end in Auckland. In the event of a large gas discovery elsewhere in New Zealand, such as the Great Southern Basin, the most likely outcome would be a shift in the location of new CCGT plants closer to the gas supply assuming the gas and electricity transmission costs are not prohibitive.

- Proximity to transmission. Unless the CCGT plant is fully embedded, it will need to connect with the transmission grid. Transmission infrastructure is relatively expensive. To minimise the impact of transmission investment on the economics of the plant, it should be sited close to existing transmission that would require limited augmentation to connect the project.
- Proximity to suitable water supply. Significant water is required to cool the steam condenser in particular. Sea water is often used when proximity to the coast is an option. Water demands at inland sites can be a significant impediment to project feasibility. This demand can be reduced by dry or closed-cycle cooling – although this comes with an associated cost.

Environmental Issues

Part of the attraction of CCGT plants is that, when compared with coal generation, the environmental footprint of a CCGT plant is substantially smaller. Indeed, increased use of CCGT plants to replace new and/or existing coal generation has been seen by many as an "easy win" in the context of the current carbon debate.

The combustion of gas in a CCGT is associated with the usual concerns over emissions associated with fossil fuels. However, many of these emissions are minimised through special combustion processes and catalytic controls.

Carbon dioxide is a particular concern given the increased focus on greenhouse gases. However, CCGT plants produce less than half the carbon dioxide output per unit of energy compared to coal generation due to their superior efficiency and the higher hydrogen to carbon ratio of methane.

The physical footprint of a CCGT facility is low and is significantly smaller than that required for conventional coal generation. It is the low profile of CCGT facilities combined with their low particulate production that makes them ideal for construction close to metropolitan demand centres. To date, there have been relatively few problems with consenting new CCGT sites in New Zealand.

10.5 Economics

Broad Economic Drivers

Like all forms of thermal generation, the economics of CCGT production are driven particularly by fuel costs. For CCGT generation, 60-70 percent of the LRMC is attributable to the cost of gas.

The various plant-specific investment costs are also obviously important. To some extent, these are driven by location and environmental factors. Other elements that affect investment costs include the technology generation, the number, size, and configuration of gas and steam turbines, and a variety of other project-specific costs.

The load factor of CCGT projects also affects their economics. These stations are suited to having a high load factor. However, load factors may decrease because of, for instance transmission constraints or gas price volatility. As the load factor decreases, the LRMC of these plants increases.

LRMC of a Generic CCGT Plant

An assessment of the LRMC of a typical CCGT project is presented in Figure 9.

TABLE 4:	STANDARDISED GGGT LRMCs
Gas Price (/GJ)	LRMC (/MWh)
$4.0	$55.5
$5.0	$63.0
$6.0	**$70.4**
$7.0	**$77.9**
$8.0	$85.3
$9.0	$92.8
$10.0	$100.3
$11.0	$107.7
$12.0	$115.2
Capex: $1,200/kW, O&M: $6.5/MWh No Carbon Price	

For this analysis, we have assumed that the plant is operated as a baseload plant.

The importance of the cost of gas is clear, with 65 percent of the total LRMC of $74/MWh being driven by the fuel price (assuming a gas price of $6.5/GJ). In contrast, the various capital components contribute only 27 percent of the total with the remaining 8 percent made up by operating and maintenance costs. Note that a $15/t carbon price increases the cost of the project by around 8 percent to $80/MWh – assuming that the reservoir gas is similar to the New Zealand specification (NZS 5442).

Gas Prices

Table 4 shows the sensitivity of the LRMC to changes in gas price. Broadly, the LRMC increases by $6-7/MWh for every $1 increase in gas price.

The current market "consensus" on gas prices place the current all-in costs of a new CCGT plant at somewhere between $70/MWh and $78/MWh. Note that this excludes any carbon effects which would add another $6/MWh (for a $15/t CO_2 price) assuming a New Zealand gas specification. Also note that current LNG prices would likely drive the LRMC of a new CCGT plant to levels above $100/MWh.

CCGT Costs

The capital costs of CCGT plants during the 1990s fell rapidly, driven by the large increases in installed worldwide CCGT capacity. Analysis of the capital costs of CCGT plant worldwide during this period shows a reduction of 25 percent for each doubling of cumulative installed capacity (Department of Energy Conversion, Chalmers University of Technology, 2001). By 2025, a 10 percent improvement in station efficiency is possible. However, it is unclear if CCGT capital costs will continue to decline in combination with these plant improvements. We have assumed that capital costs remain at current levels.

The published capital costs of CCGT projects in New Zealand are graphed in Figure 10. CCGT capital costs have varied, ranging from a relative low of $920/kW ($350 million) for Otahuhu B through to $1,350/kW ($520 million) for Huntly e3p. Initial commissioning problems at both the Taranaki and Otahuhu CCGT plants have not prevented new CCGT stations being the thermal technology of choice for various industry participants. CCGT plant comprising a single gas turbine coupled with a single steam turbine appear to offer apparent economies of scale; this is the configuration of most New Zealand CCGT plants. Plants such as Southdown and the proposed Rodney Plant, that use multiple smaller turbines have higher capital costs, but can offer the advantage of greater security should a turbine go off-line.

CCGT LRMC Range

Three wholesale gas scenarios have been analysed to provide a range on the LRMC of a new CCGT plant:

1. Cheap gas: Plentiful gas available at prices of $5/GJ or below. This scenario requires a large indigenous gas find.
2. Moderate gas: Sufficient gas available at prices between $6-8/GJ. This scenario is consistent with incremental indigenous gas discoveries.
3. Expensive gas: Under this scenario, there are limited volumes of indigenous gas and the gas price increases above $9/GJ. This scenario is consistent with the importation of LNG.

The LRMCs of a CCGT plant under these scenarios are graphed in Figure 11.

Figure 11 shows that the LRMC of CCGT plant varies significantly depending on the price of gas. With a low gas price, the LRMC of CCGTs is low (around $52 – 64/MWh without a carbon price) and dominates most other generation options (see Part A). At the other price extreme, the LRMC of CCGTs is relatively high. Under this scenario, new CCGT plant is probably uneconomic. In this scenario, gas-fired generation would be limited to existing plant, where the capital costs are sunk.

LRMC Curve

Figure 12 shows the depth of gas-fired CCGT opportunities possible in New Zealand and the LRMC curve assuming a $6.50/GJ (at Taranaki) gas price. The steps on the curve reflect increasing gas transportation costs as the CCGTs are placed further away from Taranaki as well as additional infrastructure costs for sites that are in greenfields locations. The impact of a $15/t carbon price on the LRMC curve is also shown in the graph.

FIG 10: **NEW ZEALAND CCGT CAPTIAL COSTS**

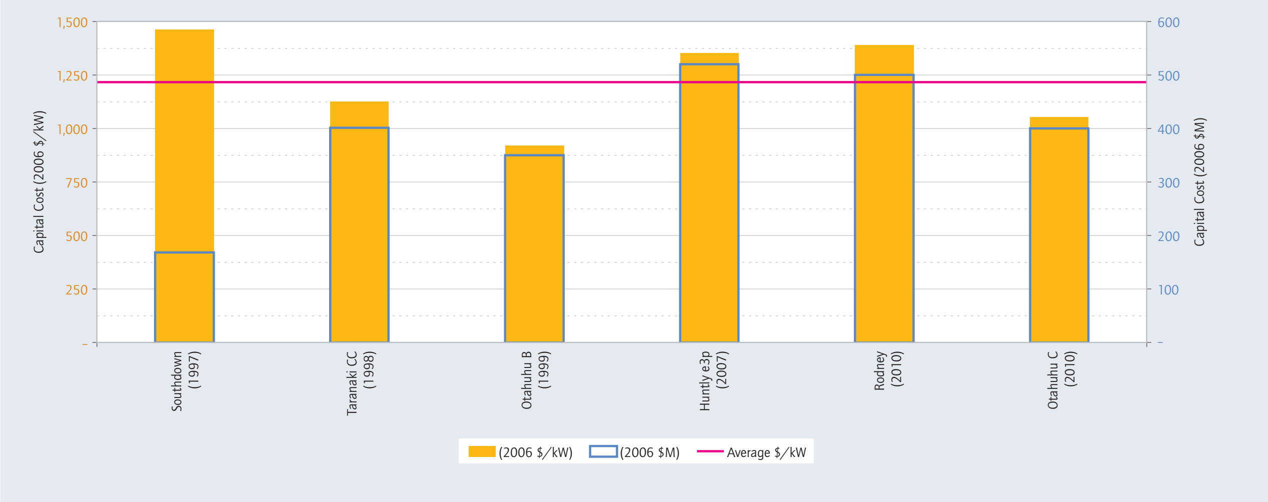


FIG 11: **GENERIC LRMCS OF CCGTS**

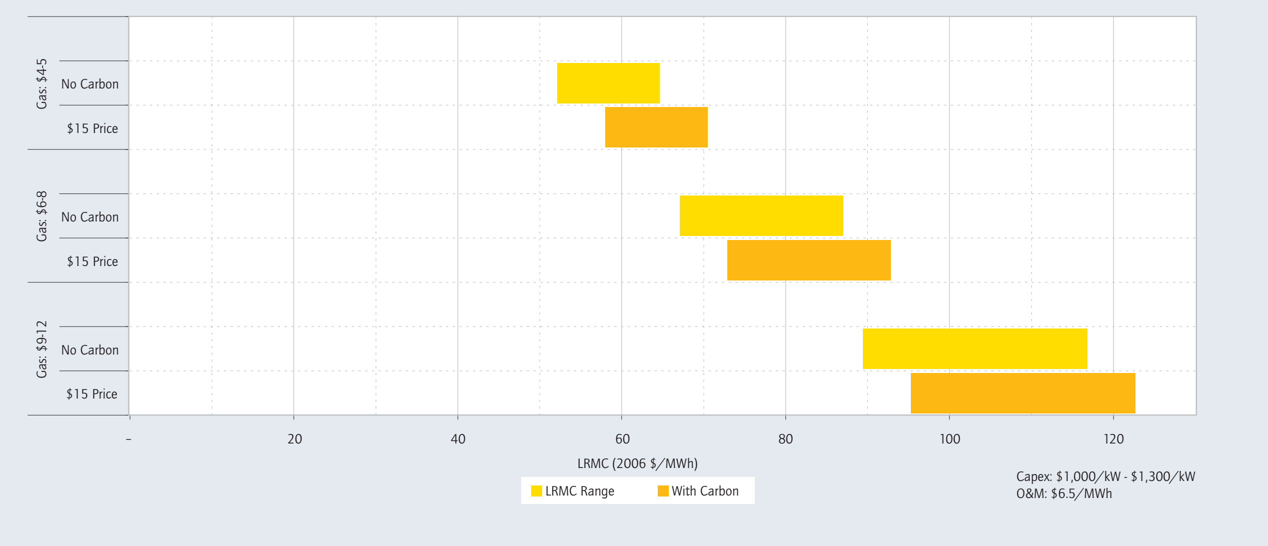
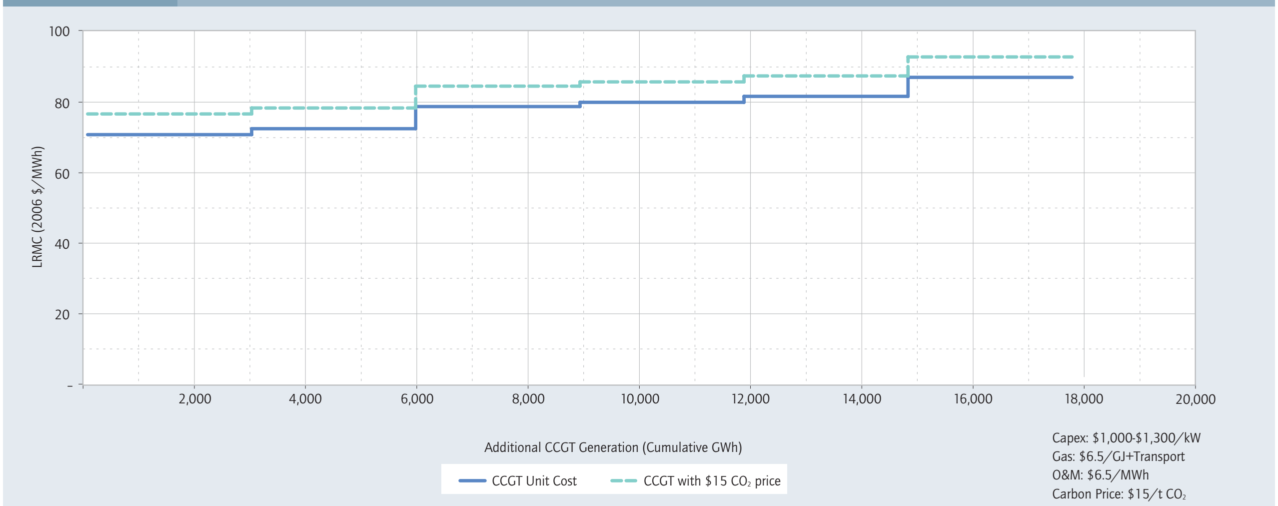


FIG 12: **LRMC COST-CURVE OF CCGTS (MODERATE GAS PRICE)**



11.0

Coal Generation

New Zealand has a huge coal resource, some of which is currently used to generate electricity. However, most economic coal-fired power station opportunities are far away from centres of demand. The cost of mitigating adverse environmental effects including CO_2 emissions, makes many greenfields coal generation options uneconomic.

11.1 Introduction

New Zealand has a relative abundance of coal, with recoverable reserves estimated to be around 8,600 million tonnes (Mt)[10]. Coal is New Zealand's largest known fossil resource. Recoverable lignite reserves alone are estimated to have energy content around 20 times greater than the Maui field.

Despite the size of this domestic resource, coal has had a relatively limited role in New Zealand's electricity sector. This outcome has been largely the result of the country's abundant renewable energy resources – predominantly hydro but latterly also geothermal and wind.

Meremere A was New Zealand's first major coal-fired generation plant. It was commissioned in 1958 and had a 210 MW generation capacity. Meremere A was decommissioned in 1990.

Huntly Power Station is New Zealand's largest thermal plant. The plant is a dual-fired plant, able to operate on both gas and coal. Until 2003, Huntly operated predominantly on gas from the Maui field. Following the re-determination of Maui gas reserves in 2003, the station has been fuelled mainly by coal. As gas reserves have tightened and demand has continued to rise, Huntly has switched from operating as a hydro-firming plant to being a base-load power station.

11.2 The Role of Coal Generation

Coal-fired generation plant produces significant volumes of electricity; generation from coal in the year ended September 2005 was 4,585 GWh. Coal plant plays a role in balancing the inherent variability of hydro generation. Unlike gas-fired generation, whose domestic fuel supply is currently shrouded with uncertainty, coal is readily available. As noted above, New Zealand has large coal reserves, including sub-bituminous and lignite coals that are suited to electricity generation. International sub-bituminous coal is also used.

Under the right market conditions, coal-fired generation, including *new* plant, can form part of New Zealand's generation mix. The economics of a number of specific coal generation options are detailed below.

11.3 Issues

As Figure 5 in Part A showed, the economics of new coal-fired generation are marginal, compared with other generation types. For instance, *if* there is readily available indigenous gas at prices around current reported levels, CCGT plant dominates new coal stations as the preferred form of new thermal generation.

[10] Total reserves are estimated to exceed 15,000 Mt.

For a new coal plant to be economic, the various external factors that affect the station's cost structure must "stack up". These factors fit into two broadly overlapping categories:

- location issues
- environmental issues.

Location Issues

The location of a coal plant significantly affects its economics. This is shown in the next section, where various coal generation project options, including their various characteristics, are discussed. The location factors include the following:

- Proximity to suitable port. If coal is to be imported or shipped from a domestic coal source, the station needs to be located relatively close to a major port so that shipping costs are reduced. For international coal the port should ideally be capable of handling large bulk carriers – for example, Panamax vessels, which are typically around 60,000 tonnes capacity. This allows the average shipping cost per tonne to be minimised. The port should not require extensive modification, as this could significantly increase total project costs.
- Proximity to rail and/or road infrastructure. For both internationally and domestically sourced coal, coal-fired generation should be located close to existing road and rail infrastructure to minimise transport costs. The economic discussion below highlights the sensitivity of plant economics to these transport costs. Lignite-fuelled plants are particularly sensitive to transport costs because of the significantly lower calorific value and higher moisture content of this form of coal.
- Proximity to coal resource. Given the sensitivity of coal-fired plant economics to transport cost, these plants should ideally be located close to the resource. For example, the Huntly Power Station and Meremere A were located close to the Waikato coal fields. Given the projected economics of lignite-fuelled generation, these plants are economic only if they are located within the vicinity of their fuel source.
- Proximity to suitable water supply. Water is required to cool the plant. In some projects, sea water may be used as part of the flue gas desulphurisation (FGD) process. Water is also required as part of a plant's waste management processes.
- Proximity to transmission. Unless the coal plant is embedded, it will need to connect to the transmission grid. Transmission infrastructure is relatively expensive. To minimise the impact of transmission investment on the economics of the plant, it should be sited close to existing transmission that would require limited augmentation to connect the project.

Environmental Issues

Environmental issues affect all infrastructure investment, and generation plant is no different in this regard. However, as the public discussion over Mighty River Power's proposed Marsden B plant has highlighted, coal-fired generation comes under particular focus.

This focus is not surprising. Though the coal resource is relatively plentiful, it is also one of the most impure fuels. Combustion of coal results in the emission of a range of pollutants including coal ash[11] and flue gases. These flue gases include the oxides of carbon, nitrogen and sulphur. Resource consent restrictions limit the production of these various impurities. Many plants are installed with infrastructure such as FGD to restrict these emissions.

Historically, less attention has been given to the emission of carbon dioxide (CO_2) from these plants. CO_2 emissions are the leading form of greenhouse gas (GHG) emissions. Coal-fired generation emits CO_2 in the order of 980t/GWh compared with around 680t/GWh for open cycle gas turbines and approximately 380t/GWh for combined cycle gas turbines.

As the Kyoto Protocol has come into force, increased focus has been placed on reducing GHG emissions from coal generation. The implications of these environmental issues for coal-fired generation plant include:

- With standards becoming increasingly stringent, it is expected that an FGD process would be required for most, if not all, new coal-fired power stations. The process required for a particular project depends on the project's individual characteristics including sea water availability and properties of the coal being used. Regardless of the process implemented, FGD is relatively expensive.
- There is increased likelihood that carbon emissions will need to be factored into the cost of thermal generation. This may be through some form of carbon charge or through increased capital costs, for example carbon sequestration. As a guide, a $15/t carbon price would add at least $15/MWh to the cost of coal-fired generation.
- There is increased resistance to the siting of coal-fired power stations, particularly in locations close to heavily populated areas. The recent debate over Marsden B is an example of this heightened awareness. RMA-related issues are likely to further limit the location options for coal-fired plants, on top of the economic drivers listed previously.

11.4 Economics

Broad Economic Drivers

The economics of particular coal-fired generation projects hinge on a variety of factors, including those discussed above. Like all forms of thermal generation, the economics of coal are driven particularly by fuel costs. For coal generation, the following factors are relevant:

- The type of coal. Broadly, the relevant coals for generation are lignite and sub-bituminous coals. However, within these classifications, the chemical properties differ significantly, depending on the particular source of the coal.
- The price of coal.

The various plant-specific investment costs are also important. To some extent, these are driven by location and environmental factors. Other elements that affect investment costs include the type of station, the number and size of generation units and a variety of other project-specific costs.

11 Composed primarily of oxides of silicon, aluminium, iron, calcium, magnesium, titanium, sodium, potassium, arsenic, mercury, and sulphur, plus small quantities of uranium and thorium.

TABLE 5: COAL STATIONS REVIEWED

Location	Plant Configuration (MW)	Coal	Coal Price (NZ$/GJ)
Southland			
Tiwai Point	1 x 350 1 x 500 3 x 350	Sub-bituminous (imported)	3.85
Ashers–Waituna	1 x 350 1 x 500 3 x 350	Lignite (from Ashers- Waituna field)	1.06
Awarua	1 x 350	Sub-bituminous (from Ohai field)	1.58
Taranaki			
Motunui	1 x 350 2 x 350	Sub-bituminous (imported)	3.64
Toko	1 x 350 2 x 350	Sub-bituminous (imported)	3.73
New Plymouth (existing NPPS site)	1 x 350 2 x 350	Sub-bituminous (imported)	3.54
Patea	1 x 350 2 x 350	Sub-bituminous (imported)	4.04

TABLE 6: CAPITAL COST FOR GENERIC COAL-FIRED POWER STATIONS AT VARIOUS COAL SITES

Location	Configuration		Capital Costs ($ M)							$/kW
	Gross (MW)	Net (MW)	Power Plant	Site Specific	Other EPC Contractors	Coal Mine	Pre-Financial Close	Other	Total	
Taranaki										
Motunui	350	316	570	129	314	0	37	81	**1,131**	**3,232**
	2 x 350	2 x 316	1,034	170	568	0	56	142	**1,971**	**2,815**
Toko	350	317	567	108	312	0	37	79	**1,104**	**3,153**
	2 x 350	2 x 317	1,029	154	565	0	56	140	**1,944**	**2,777**
New Plymouth	350	317	502	92	277	0	34	70	**974**	**2,783**
	2 x 350	2 x 317	913	121	501	0	50	123	**1,709**	**2,441**
Patea	350	316	567	82	312	0	36	77	**1,074**	**3,069**
	2 x 350	2 x 316	1,029	118	565	0	55	137	**1,904**	**2,720**
Northland										
Marsden B	320	300	-	-	-	-	-	-	**400**	**1,250**
Southland										
Tiwai	350	318	494	104	270	0	34	69	**971**	**2,774**
	500	454	656	104	361	0	40	91	**1,253**	**2,505**
	3 x 350	3 x 318	1,365	129	751	0	68	180	**2,493**	**2,374**
Ashers-Waituna	350	313	556	110	325	33	38	82	**1,144**	**3,267**
	500	446	685	114	402	47	43	101	**1,393**	**2,785**
	3 x 350	3 x 313	1,459	160	856	98	76	207	**2,856**	**2,720**
Awarua	350	324	443	71	244	0	31	61	**850**	**2,430**

The load factor of coal-fired generation projects also affects their economics. These stations are suited to having a high load factor; as the load factor decreases the LRMCs of these plants increase.

Project-specific Evaluation

We have conducted pre-feasibility studies on a range of greenfields projects. For each project, the issues identified above have been reviewed, including the type of coal available and various power station configurations. We have also analysed the economics of a brownfields plant to understand how project economics vary by project type.

Greenfields Projects

A number of specific generation project options have been evaluated. This exercise was based on a generic coal project model, though individual locations and project-specific factors were included in this assessment.

The projects are clustered into two geographic regions:

- Southland region – using the coals in the area (lignite and sub-bituminous)
- Taranaki region – using sub-bituminous coal imported to the region (either from elsewhere in New Zealand, or internationally).

All of the options evaluated involve plant designs that include standard pulverised fuel boilers, producing supercritical steam at 250 bar, with temperatures in the range of 565–580°C.

The specific options evaluated are included in Table 5. The coal price is an estimated delivered price, which includes an estimate of relevant transport costs. These transport costs include, where relevant, estimated shipping, port, rail and trucking costs.

Although lignite is significantly cheaper than sub-bituminous coal it contains far less energy. For instance, Ashers-Waituna coal is estimated to have a gross calorific value (or higher heat value – HHV) of around 10.3 MJ/kg. In contrast, coal from the Hunter Valley, Australia, is around 26.1 MJ/kg. Lignite is much higher in moisture, which reduces the

TABLE 7: LRMC ESTIMATES FOR GENERIC COAL-FIRED POWER STATIONS AT VARIOUS COAL SITES

Location	Config. (MW)	LRMC ($/MWh)	
		Without carbon price	With carbon ($15/t CO_2)
Taranaki			
Motunui	350	104	117
	2 x 350	94	108
Toko	350	103	117
	2 x 350	94	108
New Plymouth	350	94	107
	2 x 350	86	99
Patea	350	105	118
	2 x 350	97	110
Northland			
Marsden B	320	70	84
Southland			
Tiwai	350	102	116
	500	95	109
	3 x 350	92	106
Ashers-Waituna	350	86	102
	500	75	91
	3 x 350	72	88
Awarua	350	75	89

relative efficiency of the station: for instance, more fuel must be conveyed and milled, more ash must be processed and more energy is required to manage the moisture.

Table 6 summarises the estimated capital costs of the various coal generation projects analysed.

These coal generation projects exhibit strong economies of scale: a project that has twice the generation capacity has significantly less than twice the capital costs. Economies of scale are present in most reported categories, but are particularly strong for site-specific costs. This is not surprising; for instance, many site costs are incurred irrespective of the size of the plant. Because coal generation exhibits these economies of scale it makes sense economically to build relatively large plant. However, transport and transmission limitations affect this conclusion.

As discussed before, transport-related costs can potentially be significant for coal plant. Direct transport capital costs are as high as 36 percent of total site-specific costs in the examples in Table 6.

Together with estimated operating costs, these capital costs have been used to derive estimated long run marginal costs (LRMCs) for these specific projects. It has been assumed that the projects would run as base load generation plants. The Southland options include an estimate of the associated HVDC charge (in the order of $5/MWh).

Table 7 details the estimated LRMCs of the various projects.

The implications of a carbon charge on LRMC are also included in Table 7. While the form of a charge is unknown currently, it is likely that some carbon regime will be introduced in the next few years. We have analysed the impact of a $15/t CO_2 charge as a placeholder for the impact of a carbon regime on coal power stations.

In comparison, current estimates of carbon sequestration costs are in the range of US$100-$300/tonne (US Department of Energy, 2006). US research programmes hope to reduce this cost to US$10 per tonne by 2015; however the achievement of this would require the use of more expensive IGCC (integrated gasification combined cycle) plant where much of the CO_2 could be captured from a synthesis gas stream (Syngas) before the gas is combusted in the gas turbine. Capture of CO_2 from the flues of traditional coal-fired power stations would be extremely difficult and costly.

Brownfields Projects

We have also evaluated the LRMC of a brownfields project. This is existing plant that requires some form of refurbishment. The example used is Mighty River Power's Marsden B project. We have used the generic model developed for the above greenfields projects assessments, using publicly available investment and operating cost information.

Our high level assessment of the Marsden B project suggests that the LRMC for this plant is in the region of $70/MWh. Under a $15/t CO_2 carbon charge scenario, this increases to around $85/MWh.

Implications

Table 7 shows that the LRMCs of most greenfields coal projects are comparatively high. With a carbon charge, these projects are probably uneconomic compared with other generation alternatives.

The brownfields project has a significantly lower LRMC than greenfield options. This result suggests that this form of coal project should proceed ahead of completely new coal stations. This outcome is in fact happening with Mighty River Power's refurbishment of Marsden B.

Table 7 also highlights a point made earlier: the scale economies associated with this form of plant imply that these stations should be built with relatively large capacity. In reality, transmission and other constraints may limit this objective.

The large lignite plant has the best economics of the greenfields projects analysed, even when a carbon charge is imposed. This is shown in Figure 13 which summarises the LRMC range of greenfields plant operating on lignite and imported sub-bituminous. The result hinges on the plant being located close to the coal field so that transport costs are minimised. If this is possible, the relatively low price of lignite[12] outweighs the lower heat rate of the fuel and the financial implications of greater carbon emissions.

LRMC Curve

Figure 14 shows the LRMC curve for lignite and sub-bituminous greenfields coal-fired generation opportunities in New Zealand with and without carbon price. Note this does not include significant expenditure that would be required to increase transmission capacity for Southland generation options.

[12] Because lignite is relatively expensive to transport, it is not directly influenced by the world coal price

FIG 13: **LRMC RANGES OF GREENFIELDS LIGNITE AND SUB-BITUMINOUS PLANT**

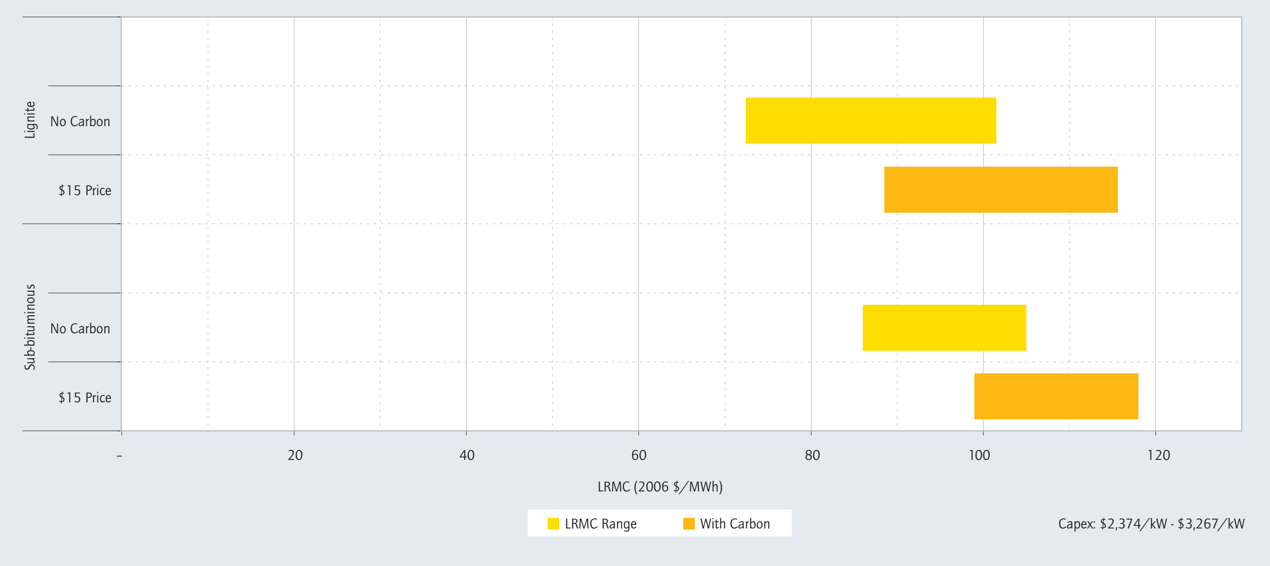
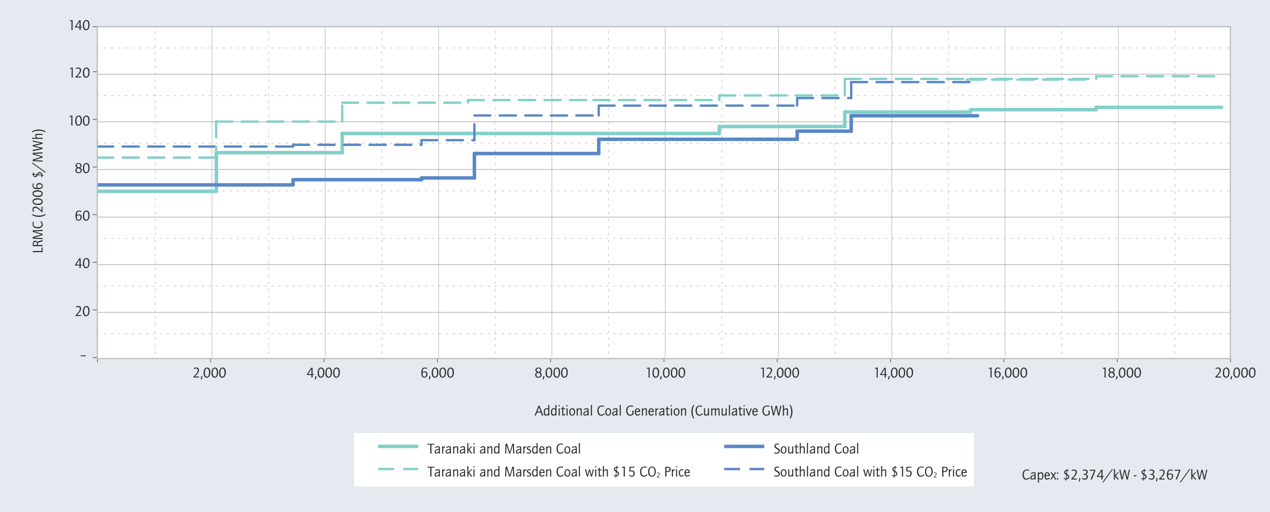


FIG 14: **LRMC COST-CURVE OF NEW LIGNITE AND SUB-BITUMINOUS PLANT**



12.0

Geothermal

New Zealand has a large geothermal energy resource that can be harnessed to produce base load renewable electricity at a competitive cost. However, upfront costs and risks associated with proving the resource and the potential for field depletion mean that lifecycle risks may be higher than for other renewable options.

12.1 Introduction

Volcanism associated with New Zealand's location on the boundary of the Indo-Australian and Pacific continental plates has resulted in numerous high-temperature geothermal systems. These systems provide the country with a world-class geothermal energy resource that has been harnessed for several hundred years. Naturally occurring hot springs have been used by Maori for cooking, preserving, heating, bathing and ceremonial purposes. More recently, geothermal energy has been used in direct applications such as heating buildings, public baths, providing process heat for commercial or industrial applications and indirect applications such as conversion to electricity.

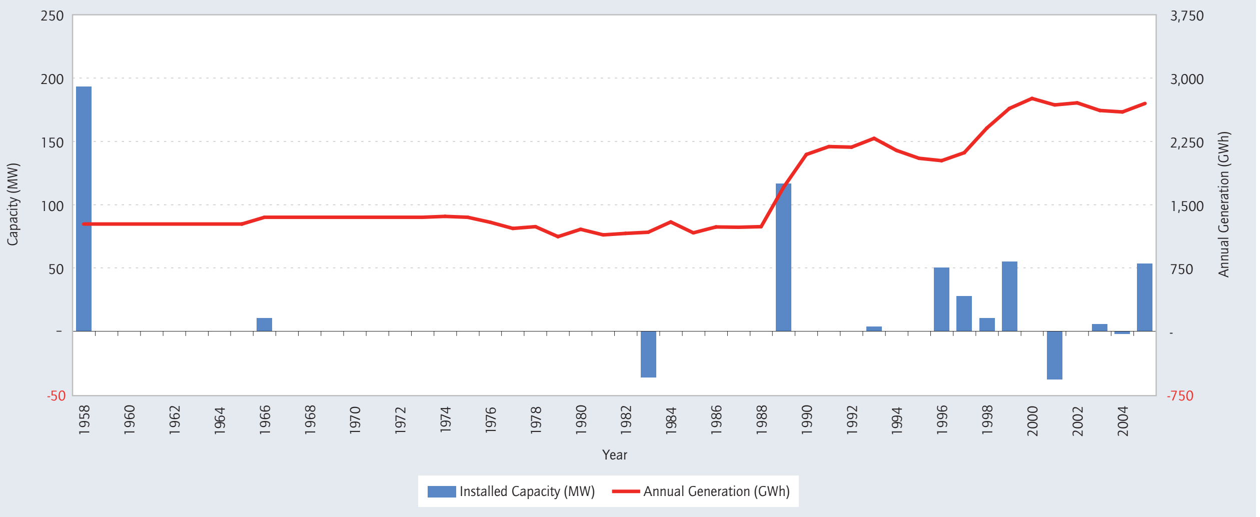
Several technologies are available for using geothermal energy to generate electricity. Traditional geothermal power stations use only the separated steam from a geothermal steam field, passing it through a condensing steam turbine. The separated hot water is either re-injected back into the steam field or in some cases discharged into a nearby river[13]. An alternative technology, particularly suitable for lower temperature resources, uses the hot geothermal fluid to boil a secondary fluid to drive smaller turbines in a closed cycle (binary plant). More recent developments extract energy from geothermal fluids with a greater overall efficiency in a "combined cycle" process involving steam turbines, binary plant heat exchangers and additional binary plant.

The first major commercial geothermal developments began with Kawerau process heat supply in 1957, followed by the commissioning of Wairakei geothermal power station in 1958. The discovery of the Maui gas field and the availability of hydro power slowed down geothermal development and it was 30 years before the second major geothermal power station, Ohaaki, was developed in 1989. The establishment of the Electricity Market in 1996 helped pave the way for a number of medium-sized geothermal power stations to be built in the late 1990s by a mixture of private developers, power utilities and Maori Trusts.

New Zealand currently has a total installed geothermal power capacity of 450 MW, producing approximately 2,600 GWh or 6.5 percent of total power generation. Figure 15 shows the sequence of geothermal development. The graph also shows the effect of steam depletion with time, caused by pressure decline in the geothermal reservoir, requiring the de-rating of Wairakei and

[13] Discharge into a river would almost certainly be unacceptable for new developments in New Zealand, but may be permitted to continue for existing developments.

FIG 15: HISTORICAL GEOTHERMAL POWER DEVELOPMENT IN NEW ZEALAND, 1958-2005



Ohaaki power stations and replacement of a small plant at Kawerau.

Although some geothermal fields have been degraded, and others have required the drilling of make-up wells, none have been exhausted and sustainable development is possible. When properly developed and managed, geothermal systems are a reliable source of renewable energy. They can provide a source of near constant base load generation with annual capacity factors in excess of 90 percent.

12.2 The Role of Geothermal Power Generation

New Zealand's high-temperature geothermal fields are predominantly located in the Taupo Volcanic Zone. This region extends from White Island in the Bay of Plenty southwest to Mt Ruapehu. There is also the Ngawha field in Northland. There is an estimated 1,300 MW or 10,500 GWh of untapped generation potential (Ministry of Economic Development, 2004) available in high-temperature geothermal fields classified in Regional Plans as development fields. Only about 20 percent of this potential is publicly known to be investigated by developers at present, as shown in Table 8. All of these developments are brownfields investments. They are either extensions of existing power stations or new developments on producing steam fields.

There is an additional 1,450 MW (11,800 GWh) of geothermal energy potential in fields that are classified under Regional Plans as either protected or limited development (East Harbour Management Services, 2005b). There is potential for the classification of fields to be changed, if either new information about the field comes to light or a means of controlling environmental effects can be demonstrated. The agreement recently reached between the consent authorities and the developer at Ngawha is a good example of the latter[14].

There are several low temperature (30-140°C) geothermal heat resources in the North Island and even a few in the South Island (East Harbour Management Services, 2005b). The South Island resources are isolated or are in areas of low population density. Some North Island low temperature resources have already been developed for heating of domestic homes, pools, glasshouses and so on. Further development of low-temperature resources might be possible with the uptake of ground source heat pumps. However, high costs and limited uptake make it unlikely that these will have a significant impact on national electricity supply and demand at current power prices.

12.3 Issues

There are many issues that will affect the economic development of high-temperature geothermal power, including:

Geothermal Resource Assessment

The economic and technical feasibility of a particular geothermal power development will be highly dependent on the structure and attributes of the geothermal resource. These include factors such as the following:

- Size. Depths for production wells in New Zealand are typically between 1,000 and 1,500m, but can range anywhere between 500 and 2,500m. At shallower depths, geothermal temperatures are reduced through the cooling effect of groundwater and the well is vulnerable to cool groundwater inflows. Generally the larger the field, the greater the geothermal power development it can sustain – depending on the other reservoir characteristics discussed below.
- Porosity and permeability. Higher porosity (void space in rock) results in a greater amount of fluid stored in the reservoir and high permeability (degree to which the voids are interconnected)

14 Previously, expansion was held up because of environmental concerns; with a successful trial of supplementary injection it appears those concerns have been resolved.

TABLE 8: POTENTIAL AND RECENT GEOTHERMAL POWER DEVELOPMENT IN NEW ZEALAND

Region	Company	Project	Capacity (MW)	Annual Gen. GWh	Stage
Upper North Island	Top Energy	Ngawha ext.	15	120	Consented
Central North Island	Mighty River Power	Kawerau	70	550	Consented
		Rotokawa ext.	33	270	Investigations application filed
	Geotherm Group	McLachlan PS	60	475	Drilling production wells, first well on test
	Contact Energy	Te Mihi Drilling	25	205	Steam pipeline construction
		Ohaaki Drilling	10	80	Drilling production wells
		South Tauhara	N/A	N/A	Investigations
Total NZ			**213**	**1,700**	

allows the fluid to be extracted more easily. Most New Zealand fields have relatively high permeability.

- Thermodynamics. Higher temperatures and pressures enhance electrical conversion efficiency and high fluid enthalpy (heat content) maximises energy per unit mass and reduces reinjection load.
- Depletion rates. With commercial production the geothermal resource may become depleted over time. The amount of depletion is dependent on how well the reservoir is capped, pressure drawdown is dispersed and cold water into the resource is managed. Depletion may also be affected by stimulation of hot recharge from depth.
- Cold water incursion. As the pressure in a reservoir declines, it is possible for cold groundwater to encroach into the field via major fractures or springs, negatively affecting power production (as at Wairakei and on a large scale at Ohaaki). If this occurs, production needs to be shifted to areas sufficiently removed from the groundwater incursion and/or wells drilled and cased to greater depths.
- Reinjection. Reinjection of geothermal fluids is generally seen as environmentally responsible as well as contributing to resource sustainability. However, this can sometimes have a negative effect on a reservoir, if reinjection fluids are able to move rapidly back into the production area[15].

In order to accurately assess the below ground parameters listed above it is generally necessary to drill an exploration well and up to four delineation wells, depending on the size of the resource and the desired power plant size. The upfront cost of this is in the order of $10-25 million for first stage power plants ranging from 20 to 100 MW capacity.

Resource Access Issues

A potential geothermal power station developer will need to gain access to land above the resource as well as rights to develop the field. Resource access issues include the following:

- Resource ownership. All geothermal resources in New Zealand are owned by the Crown, but rights to access the resource lie in the first instance with the owner of the land. Potential developers need to negotiate access rights with the landowner, purchasing land outright, securing easements or entering a joint venture – all come at a cost and take time.
- Iwi. Some areas may be held within a Maori Trust, requiring discussions and agreement with many parties including landowners, iwi and the Crown via the Waitangi Tribunal. This provides an opportunity to achieve local benefits, such as occurred at Mokai where a large geothermally heated greenhouse complex was developed in conjunction with the power station.
- Resource allocation. Rights to develop a geothermal resource are granted by regional authorities under the RMA. Securing a resource consent requires a comprehensive application covering environmental effects, issues of sustainability and a development plan. Processing a resource consent can be time consuming and in some cases take several years, depending on the nature of objections, level of competition for the resource and whether it is appealed to the Environment Court.

Environmental Issues

Geothermal developments are generally required to demonstrate sustainability and limited environmental effects under the RMA. Specific issues that need to be addressed include the following:

- Impact on natural features. The potential for adverse impacts on natural tourist features such as geysers, hot springs and mud pools needs to be assessed. Consent conditions requiring preservation of these features may represent a significant constraint on resource use, though if a field has been designated for development the sensitivity and conservation value of thermal features will already have been taken into account.
- Discharge gases. Geothermal waters typically contain dissolved gas (principally carbon dioxide and hydrogen sulphide), most of which moves into the steam phase when the water boils. High levels of hydrogen sulphide can pose an odour nuisance, though in New Zealand the consent authorities have taken a fairly relaxed approach, acknowledging that there are already significant natural levels of H_2S in some areas[16].

[15] In most New Zealand fields in the Taupo Volcanic Zone the degree of anisotropy (selective fracture control on permeability) is low compared with fields elsewhere in the world where this has been a significant issue.

[16] No geothermal power plant in New Zealand has had to adopt H_2S abatement technology, though these are commercially available should it ever become an issue.

- Carbon dioxide. Depending on the field, emissions of CO_2 from geothermal power stations range from about 30 t/GWh to 400 t/GWh, generally less than an equivalent sized gas-fired combined cycle station (around 400 t/GWh) and significantly less than for a coal-fired power station (around 800-1000 t/GWh). The imposition of a carbon charge would therefore affect some geothermal developments more than others.
- Subsidence. The risk of subsidence needs to be assessed prior to development and should be substantially reduced by reinjection.
- Field classification. Many geothermal fields are protected or classified as "research" in Regional Plans prepared under the RMA – the latter requires the potential developer to prove that the field is not linked to adjacent protected fields or natural features.
- Sustainability. About 80 percent of geothermal fields are governed by Regional Plan requirements which, in effect, require that they be exploited at a rate which ensures the resource remains exploitable at the end of 100 years. This will mean that the scale of a geothermal power development will be limited by the resource consent rather than the resource itself (East Harbour Management Services, 2005b), and may reduce the potential benefits from economies of scale. This requirement is, however, currently under appeal to the Environment Court and may well be relaxed.
- Water loss and vapour emissions. The commercially available binary plants are mainly air-cooled, whereas conventional condensing steam turbines generally use open cycle wet cooling towers. The former system may be perceived as having a lower environmental impact in terms of emissions and net loss of fluid. However, to date, authorities have not gone as far as making this a mandatory consideration. Either type of cooling system can be employed, subject to specific project requirements and conditions.

Transmission Issues

Many of the geothermal fields in the Taupo Volcanic Zone have major 220 kV or 110 kV transmission lines nearby.

This can be an advantage for geothermal developments over other renewable projects elsewhere in the country, although there is limited transmission capacity in the region before constraints would become an issue. In addition, the high cost of connection at 220 kV might introduce diseconomies of scale to the economics of geothermal developments that have been limited in size through consenting issues. Where developments are small enough to connect into local distribution lines they may gain an economic benefit from both a lower cost connection and reducing the lines company's interconnection charges.

12.4 Economics

Broad Economic Drivers

The main drivers of economic geothermal power station development are:

- Geothermal resource. The geothermal resource characteristics will define the depth and placement of wells to be drilled, the lifetime energy potential and ultimately the particular technology that is used to convert geothermal heat to electricity.
- Capital costs. About 40-50 percent of the total cost of a geothermal development is the power plant, with a similar percentage in steam field pipelines, separators and production/reinjection wells. Like wind development, the high proportion of imported power plant components means that project economics are more exposed to currency fluctuations and the state of vendors' order books at the time of development.
- Lifecycle costs. Depending on the geothermal resource characteristics, a geothermal development can have significant ongoing lifecycle costs, including remedial works due to scaling and corrosion through to the need to drill new wells to replace degraded steam resources.

Project Specific Evaluation

We have reviewed a range of greenfields geothermal projects. This analysis has been based on a generic high-temperature geothermal field, typical of those remaining for development in the Taupo Volcanic Region. The economics of several brownfields geothermal developments have also been estimated from publicly available information.

The LRMC results have been grouped into a number of generic configurations, including:

- brownfields steam drilling – involves drilling new wells and building steam field infrastructure to increase production at an existing geothermal power station such as Ohaaki
- brownfields 50-100 MW development – extension of an existing geothermal power station or development on a currently producing steam field
- greenfields – single flash condensing plant – 50 MW single pressure condensing steam turbine similar to the unit at Poihipi Power Station
- greenfields – dual flash condensing plant – 60 MW dual pressure, condensing steam plant, which uses two-stage separation of geothermal fluids, similar to three 30 MW units at Wairakei Power Station
- greenfields – binary cycle plant – 50 MW power station consisting of multiple binary cycle units, similar to plants installed at Kawerau and Ngawha
- greenfields – combined cycle plant – 64 MW power station consisting of a back-pressure steam turbine, with multiple binary cycle units either fed from low-pressure exhaust steam from the turbine or high-temperature brine from the production separators. This configuration is typical of units installed at Mokai and Rotokawa power stations, although Rotokawa is smaller.

The size of these generic projects (around 50 MW) is based on the likely size for an initial development on a typical Taupo Volcanic Zone resource. The differences in total capacity (50-65 MW) reflect

FIG 16: LRMC OF NEW ZEALAND GEOTHERMAL POWER STATIONS

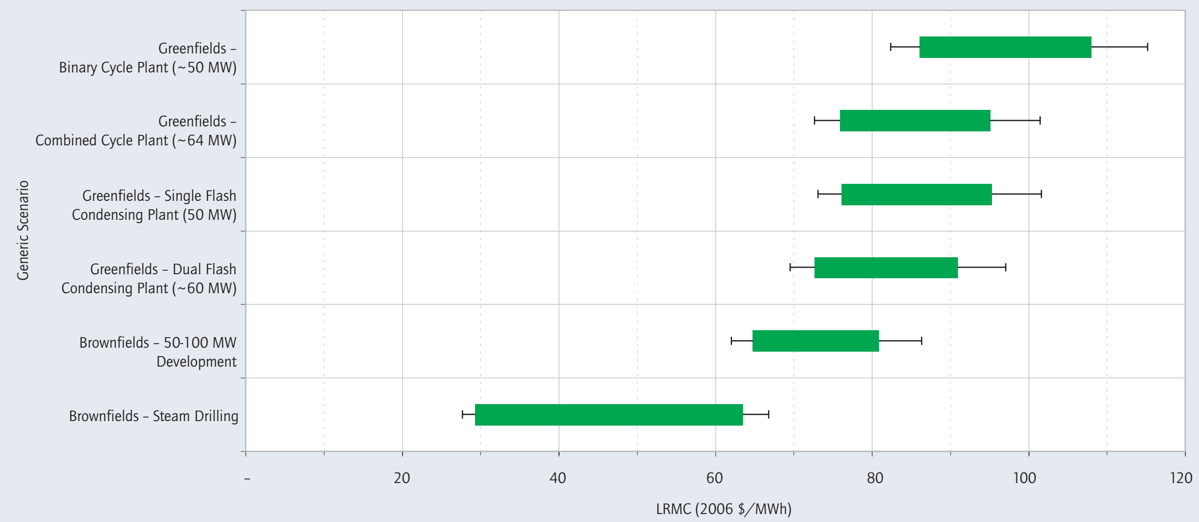


FIG 17: LRMC COST-CURVE OF GEOTHERMAL POWER STATION OPPORTUNITIES

different levels of energy extraction possible for a given fluid extraction from the different technology configurations. The choice of technology would be driven by the given characteristics of the resource. For example, in some fields, low temperatures might require that more expensive binary plants with a larger heat exchanger be used.

Figure 16 shows the LRMC range for greenfields and brownfields sites given different technology options. The ranges reflect assumptions on the success of ongoing drilling of wells during the life of the plant to maintain steam supply – ranging from successful steam maintenance to degrading by 2 percent per annum. The lines on the right side of the bars indicate the impact that a 10 percent increase in capital cost (due to factors such as a drop in exchange rate, deeper wells or more difficult transmission connection) would have on LRMC. Similarly the lines on the left side indicates the LRMC impact of a 5 percent decrease in capital cost due to factors such as easier transmission connection or a higher New Zealand dollar.

Implications

Not surprisingly, brownfields sites are the most economic of geothermal developments as these have sunk costs for supporting infrastructure and operational arrangements. However, there are only limited opportunities for continued brownfields development of existing geothermal power stations or fields (about 1,700 GWh).

The LRMC of greenfields geothermal developments are in the order of $75-85/MWh. These are competitive with other renewable options, depending on the technology used and resource consent limitations. This is provided that ongoing drilling of wells during the plant's lifetime is successful in finding new sources of steam to replenish those from wells that have degraded. There remains a risk, however, that in some cases the whole field declines. For example, if there is ingress of cold groundwater. In a case like this steam drilling may need to go further afield or deeper, at a significant cost.

About 9,000 GWh of greenfields geothermal power development potential has been identified in fields classified as available for development. Figure 16 shows that, under the right set of resource conditions, a new geothermal development is potentially economic. However, this potential needs to be proven first with a programme of drilling, at a cost of $10-25 million, on each prospective field. Drilling is required to determine the field characteristics, environmental effects and appropriate technology to harness the energy.

New Zealand has a unique history of geothermal development. Geoscientific investigation by government agencies in the early days has left a valuable legacy, which remains valid. There was also an extensive programme of geothermal exploration drilling. Data on those exploration wells is available from The Treasury. In some cases, such as Ngatamariki, the wells were commercially productive and remain available. Consequently, many of the apparently greenfields sites in New Zealand have lower resource risk, and in some cases lower costs, than in genuinely new prospects elsewhere in the world.

LRMC Curve

Figure 17 gives an indication of the LRMC cost-curve of geothermal generation opportunities on development fields in New Zealand, with and without a $15/t carbon price. For most developments this charge adds between $0.5/MWh and $4/MWh to the LRMC. Ngawha is an exception, with the tax adding a further $9/MWh, due to the high CO_2 content of this field.

This cost curve assumes successful steam drilling during the lifetime. Some points on the graph could be up to $22/MWh higher should the steam resource degrade.

13.0

Wind

Wind power is the fastest growing source of new generation being installed around the world. New Zealand has a world class wind resource that will enable wind generation to become a significant provider of renewable energy, coupled with the country's large, flexible hydro generation base.

13.1 Introduction

New Zealand is endowed with a world-class wind resource. New Zealand is situated in the Roaring Forties, which are known for their strength and are unhindered by land mass. With its narrow islands, New Zealand has a good exposure to coastal winds and its ranges and areas of elevated terrain give localised wind speed accelerations.

Wind farms are a proven, environmentally responsible and cost competitive means of generating renewable energy. Around the world, wind farms have made the transition from the realm of alternative energy to that of mainstream utility scale energy producers. New Zealand has followed this trend with the first utility scale wind turbine installed in 1993 at Brooklyn, Wellington and subsequently the first 4 MW wind farm installed in the Wairarapa in 1996. Since then wind farm development in this country has progressively increased to 168 MW installed capacity, with an additional 154 MW currently under construction and due to be commissioned in 2006/2007. Figure 18 plots this growth in capacity.

Many more wind farms are currently under consideration by a range of incumbent and new entrant developers. The part they can play in securing New Zealand's energy future and the issues that will help or hinder them are discussed in more detail.

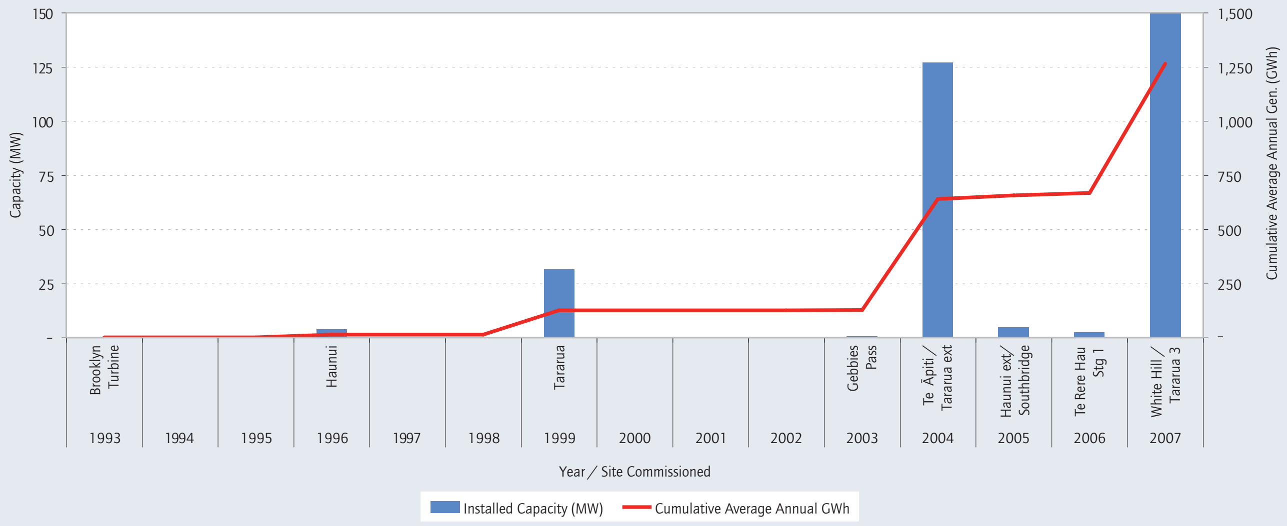
13.2 The Role of Wind Generation

Wind power generation is unlikely ever to totally replace other forms of generation such as thermal or hydro power stations. This is because the wind does not always blow when demand occurs, wind generation output is less controllable and an impractical number of wind turbines would be required to generate enough electricity. However, New Zealand has consistently strong wind conditions compared with most other countries, so wind generation has the potential to be a significant part of future generation.

New Zealand's wind conditions make wind power generation much more efficient and reliable here compared with most other countries. For example the capacity factor (percentage of theoretical maximum energy) of Te Āpiti wind farm is around 45 percent compared with international wind farm capacity factors in the order of 25-30 percent. Project West Wind's capacity factor is expected to be around 47 percent, giving it the potential to be a world-leading wind farm. It is expected to generate electricity for over 90 percent of the time.

Wind farms can also be developed and constructed relatively quickly.

FIG 18: WIND POWER INSTALLED IN NEW ZEALAND (COMMISSIONED AND COMMITTED), 1993-2007



They are now of a scale where they can make a significant contribution to meeting growing energy demand.

A study commissioned by the Ministry of Economic Development and EECA (Energy Link & MWH NZ, 2005) shows that wind farms could provide approximately 35 percent of the country's present electricity needs.

Table 9 lists some of the publicly announced wind farms that are at various stages of development but not yet committed for construction. This does not include several thousands of GWh of undisclosed wind farm sites that are at an early stage of development. It also excludes some sites that have been in the media in the past few years that have since gone quiet.

Some of the sites have been abandoned due to poor economics resulting from low average wind speeds or transmission related difficulties. It is quite possible that others on this list may also be discarded by their developers for similar reasons, even after gaining resource consent.

13.3 Issues

Wind Issues

The quality of the wind resource varies around New Zealand and, as shown in Section 13.4, average wind speed is a critical factor in wind farm economics. It should be noted that while wind farms can be consented and built relatively quickly, wind farms that have been successfully developed in New Zealand took between three and seven years from initial identification to commissioning. This development included:

- obtaining high-quality data on the site at hub height to get long-term average wind speeds
- assessing wind shear and turbulence for individual turbine yield and performance
- optimising site layout and assessing environmental effects
- tailoring the choice of wind turbine to the wind conditions of the site.

As observed internationally, during the early stages of a country's wind adoption, overestimation of wind energy on projects is relatively common. A similar trend is occurring in New Zealand. Accordingly, some of the sites in Table 9 are probably speculative, with some developers having limited knowledge of the real wind conditions of their site. In some cases developers may be proceeding with resource consent applications having done minimal amounts of design work.

Location Issues

The location of a wind farm is driven by suitable topography and the nature of the wind resource itself. Wind farms need to be built in locations where they can make the best use of strong, unimpeded wind flows, such as hilltops and ridgelines. These geographical locations are generally either near the coast or inland at higher elevations.

Because wind farms need to be sited where the resource is, a number of location factors come into play:

- Proximity to transmission. Many wind farm sites are remote from transmission lines. While some may be located close to local distribution lines, generally these do not have enough capacity to connect wind farms greater than 30-40 MW. Connection to Transpower's 110 kV or 220 kV grid is more expensive, and it can be more difficult to secure easements for a higher-voltage connection. Transmission infrastructure becomes more expensive and difficult as the distance between existing transmission infrastructure and the wind farm site increases.
- Proximity to suitable port. Wind turbine components are generally imported from overseas and are of significant size and

TABLE 9: POTENTIAL WIND DEVELOPMENT IN NEW ZEALAND

Region	Company	Project	Wind Class[18, 20]	Capacity (MW)	Ave Ann.GWh[17]	Stage
Auckland/North	Meridian Energy	Gumfields	2	60	200	DOC concession
	Meridian Energy	Pouto	2	300	975	Investigations
	Genesis Energy	Awhitu	2	19	65	Consented/Abandoned
				379	1,240	
Waikato	WEL Energy	Te Uku	2	72	*220*	Consultation
	Taharoa C	Kawhia Harbour	2	100	*310*	Consented
	Ventus Energy	Awakino	2	42	*125*	Consented/Abandoned
	Ventus Energy	Taumatatotara	2	44	*135*	Consented
				258	790	
East Coast North Island	Eastland	Mokairau	2	12	35	Appealing Com. Com. decision
	Unison/Roaring 40s	Titiokura Saddle	1-2	45	*165*	Consented
	Unison/Roaring 40s	Te Waka	1-2	111	405	Environment Court appeal
	Hawke's Bay WFL	Titiokura	1-2	225	800	Consented
				393	1,405	
Manawatu	NZ Windfarms	Te Rere Hau Stage 2	1	46	170	Seeking capital
	Energreen	Motorimu	1	110	*400*	Investigations
	Mighty River	Turitea	1	150	*550*	Investigations
				306	1,120	
Wellington/Wairarapa	Meridian Energy	West Wind	1	210	850	Environment Court decision pending
	Wainui Hills (WFD)	Wainui Hills	1	30	*110*	Investigations
	Greater Wellington	Puketiro	1	90	*360*	RFP for Developer
	Greater Wellington	Stoney Creek	1-2	60	*220*	RFP for Developer
				390	1,540	
Upper South Island	TrustPower	Seddon	3	80	245	Abandoned
				80	245	
Otago/Southland	Meridian Energy	Project Hayes	2	630	2,040	Lodged consent
	TrustPower	Lake Mahinerangi	2	200	*800*	New consent to be lodged
		Mahinerangi Stage 2	2	100	*400*	May consent in 3-5 years
	Windpower Otago	Rock & Pillar	2	25	*85*	Investigations
	Roaring 40s	Cairnmuir Hill	2	60	*210*	Investigations
				1,015	3,535	
Total NZ				**2,821**	**9,875**	

17 Note: generation figures in italics are best estimates based on capacity and likely capacity factor given high-level wind resource information.

weight. Because of this, transporting generation infrastructure to the wind farm site is costly. Total transport costs are affected significantly by the distance of the site from a suitable port.

- Roading infrastructure. Many of the wind turbine components are oversized loads (for example 35-45m long blades), which can present a challenge in transporting to site, particularly in areas with winding, narrow roads or with low bridges. Dealing with these obstacles can impose significant additional costs to a wind farm project.

Connection Issues

In addition to distance from transmission, the quality of connection can be an important factor in wind farm economics. Connection issues include:

- Grid strength. Wind generation requires a strong grid (for example sustains high fault currents) – weak grids can require significant additional investment in dynamic voltage support equipment and can potentially limit the scale of a development.
- Transmission capacity (both local and regional). This is a common issue for any generation proposal that is distant from load but many wind projects will run into local or regional transmission or distribution network constraints. The cost of relieving a constraint can sometimes be too great for a single project to bear.
- Intermittency effects. This issue is sometimes overstated by wind farm opponents. Power systems are inherently variable – user demand can swing quite rapidly and large power station units such as combined cycle gas turbines sometimes trip off. The System Operator has a number of tools at its disposal for managing this variability including frequency control and the under-frequency reserve market. New Zealand has considerable hydroelectric generation resources, particularly in the South Island, that could be used to balance wind power, particularly if the HVDC link was upgraded to allow them to contribute to frequency keeping in the North Island. Regional diversity of wind farms will also help to limit the overall variability of wind power on the system.

Environmental Issues

Many of the wind farm sites that have been built were successfully consented with limited opposition. However, new wind farms are now facing increasing opposition at the consenting stage. This has seen a number of sites being appealed to the Environment Court.

Environmental issues need to be assessed for wind farms and weighed up against the benefits. These issues include the following:

- Visibility. Because wind farms need to be located on hilltops and ridgelines, they will often make a striking feature on the landscape – a visual effect that some people like but others do not. This is often a key area of opposition: whether or not the character of a natural landscape will be significantly impacted by the development.
- Noise. Noise is often cited by opponents as being a major issue. However, design improvements mean that modern wind turbines produce limited levels of noise compared with earlier models. In particular, rotor blades have been refined to make them more efficient and reduce their aerodynamic noise and manufacturers have practically eliminated pure tonal noise from the rotor and generator assembly. Wind farm developers must comply with NZS6808:1998, a standard designed specifically for the assessment of the acoustic effects of wind turbines.
- Effect on birds. There is some concern that wind farms are associated with high bird mortality rates. Any tall structure does pose some risk to birds. A factor in determining site location is the consideration of the natural ecology of the area. In particular, a well-chosen site should avoid migratory flight paths and significant avifauna habitats.
- Construction effects. These effects may include increased heavy vehicle traffic in the vicinity of the wind farm during construction, the temporary creation of up to 10m-wide roads on the site and impacts on native flora and fauna in the area.

13.4 Economics

Broad Economic Drivers

The economics of particular wind farm generation projects hinge on a variety of factors, including those discussed above.

For wind farm generation, the following factors have the most impact:

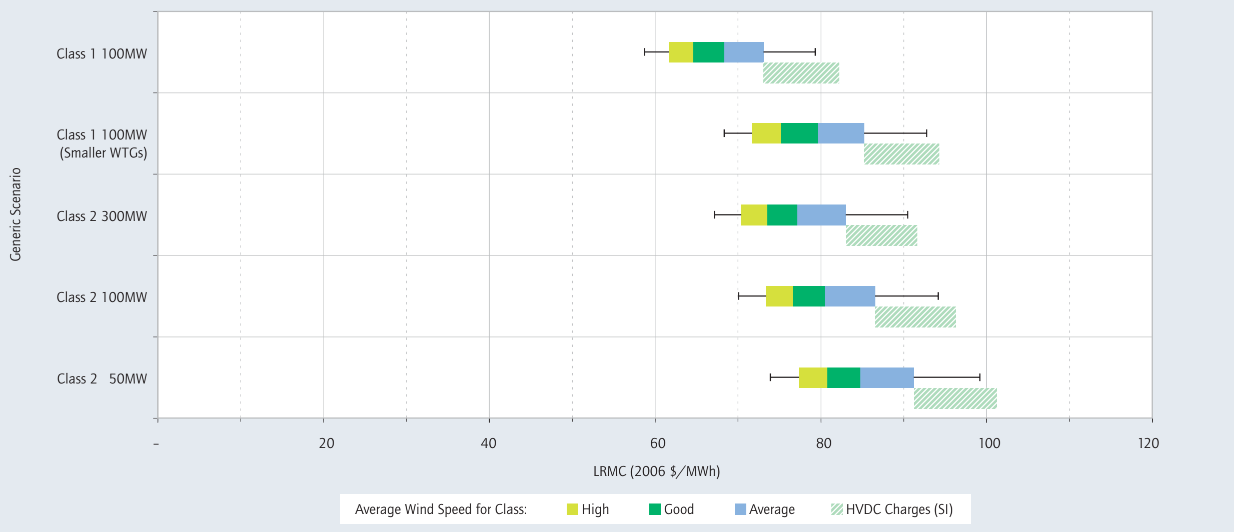
- Wind speed. Since wind turbine output is generally proportional to the cube of wind velocity, the productivity of a wind farm is highly dependent on average annual wind speed. Not surprisingly, most of the New Zealand's wind farm developments so far have been in Class 1 wind[18] regions such as the Manawatu and Wellington where average wind speeds at hub height are above 9m/s and capacity factors are in the order of 42-47 percent.
- Capital cost. Approximately 70 percent of a wind farms capital cost is associated with the wind turbine generators and towers (the proportion varies depending on the difficulty of the terrain and transmission connection). Wind turbine technology has been getting larger and cheaper in most years. However, since 2004, increasing international steel prices, increasing wind turbine demand from the USA and the falling New Zealand dollar have reversed this trend. Several of these factors are affecting the cost of other energy infrastructure to varying extents. This was reported to be a key factor in the recent cancellation of the Awhitu project.

Project-specific Evaluation

The economics of a generic 100 MW wind farm have been analysed to show the effect of the above characteristics on LRMCs and to provide a comparative analysis of wind farms in different wind regimes, terrain and physical locations around New Zealand. The base case scenario is a wind farm built on average hilly terrain, similar to White Hill or Te Āpiti. The base case assumes an easy connection to a nearby 110 kV

[18] Class 1 wind sites have average annual wind speeds at hub height above 9 m/s.

FIG 19: GENERIC LONG RUN MARGINAL COSTS FOR WIND FARMS



transmission line, and onsite static voltage control equipment, for example Statcon, and is calculated using an exchange rate of 1 NZD = 0.50 Euro.

Two wind classes have been modelled:

- IEC Class 1 with average annual wind speeds at hub height from 9 m/s (average) to 10 m/s (good) and up to 10.5 m/s (high)[19]. For these generic 100 MW wind farms a standard layout with fifty 80m rotor diameter 2 MW Class 1 wind turbines on 70m steel towers is assumed.
- IEC Class 2[20] with average annual wind speeds at hub height from 7.5 m/s (average) to 8.5 m/s (high). For these generic 100 MW wind farms a standard layout of fifty-five 90m rotor diameter 1.8 MW Class 2 wind turbines on 70m steel towers is assumed.

For the different wind classes a range of scenarios has been modelled:

- Using a larger number of smaller turbines for the same output. For example sixty-one 72m rotor diameter 1.65 MW class 1 machines instead of fifty 2 MW turbines.
- Larger wind farm (300 MW) built over several years.
- Smaller 50 MW wind farm built within a year.

The results of the scenario analysis are shown in Figure 19. The striped bars indicate the incremental effect that the HVDC charge adds to the LRMC of a new wind farm built in the South Island. The size of the impact depends on the cost and allocation of the proposed HVDC grid upgrade – the models assume a near doubling in HVDC costs by 2012.

The lines on either side of each bar provide a sensitivity on wind farm capital costs – the coloured bands (representing LRMC in relation to average wind speed) slide along the lines depending on the difficulty of the site in relation to the base case.

The high side (right-hand side) of the sensitivity lines represents a 10 percent increase in overall capital costs (for example from higher turbine prices, greater civil/geotechnical difficulty, longer transmission route or higher-voltage connection, or a drop in the New Zealand dollar against the Euro).

The low side (left-hand side) of the sensitivity lines represents a 5 percent decrease in overall capital costs (for example from lower turbine prices, easier site, onsite transmission or an increase in the New Zealand dollar).

Implications

As discussed earlier, wind speed is a key economic driver of wind farms. The LRMC of a good Class 1 site is approximately $10/MWh lower than a good Class 2 site. In each class, a difference of 1 m/s average wind speed can make a difference of $10-15/MWh on the LRMC.

The analysis shows that using smaller turbines to achieve the same wind farm output can have a negative impact on the economics as generally more land, cabling and roading are required and turbine cost per unit output is higher. It should be noted that for some sites with very difficult access, a smaller turbine may be more economic as it may be unviable to get larger turbines onto the site – however, these types of sites are likely to be less economic than those shown in Figure 19.

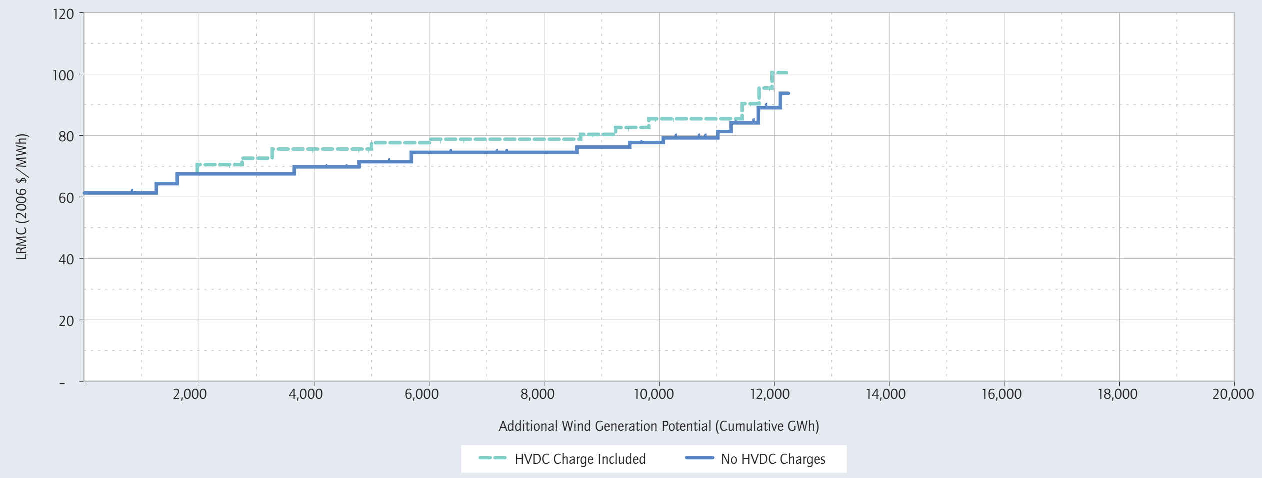
The HVDC pricing regime adds up to $10/MWh to the LRMC of a wind farm built in the South Island. This has already been cited as one of the contributing factors leading to the abandoning of the Seddon wind farm proposal.

Larger wind farm sites tend to have a lower LRMC than smaller sites, because of economies of scale. In particular,

19 Note Class 1 wind sites above 10 m/s are very rare and suitable development sites exist only around Wellington in the North Island.

20 Class 2 wind sites have average annual wind speeds at hub height between 7.5 m/s and 8.5 m/s. Sites with wind speeds below 7.5 m/s are Class 3 or 4 and are not economically viable in New Zealand.

FIG 20: LRMC COST-CURVE OF WIND GENERATION IN NEW ZEALAND



access road costs tend to be similar, and larger sites may obtain a bulk turbine discount.

A 10 percent increase in overall capital costs has a $6-8/MWh impact on LRMC. Sites that might fall into this category include those with difficult terrain or geotechnical issues, or poor surrounding roading infrastructure, and sites that are distant from transmission lines or feeding into a weak part of the grid (requiring additional voltage support).

A 5 percent decrease in overall capital cost has a $3-3.5/MWh impact on LRMC. Sites that fall into this category may have very easy terrain, have transmission lines passing through the site, or be situated close to a major port.

The above analysis does not include additional costs for providing firming of wind farm output such as possible frequency keeping charges. It is important that any future such arrangements are well considered and allow flexibility for alternative arrangements. Markets for providing auxiliary services need to be kept competitive. Changes to the way the HVDC link operates to allow South Island hydro generation to offer frequency keeping in the North Island may help meet these objectives.

As mentioned earlier, there is an increased demand worldwide for wind generation infrastructure. This is likely to affect project economics. In particular, developers without established relationships with wind turbine manufacturers may struggle to get turbines over the next few years although this should not be a problem in the longer term.

LRMC Curve

Figure 20 gives an indication of the LRMC cost-curve of wind generation opportunities in New Zealand, based on a point estimate of LRMC for individual sites and taking into account factors discussed above. The difference between the two curves is the maximum expected impact of HVDC charges on South Island opportunities.

It should be noted that the points on the curve are based on a high level best estimate of likely average wind speed and degree of difficulty. Each segment should be considered as an approximate mid point of a range that could vary by as much as the LRMC ranges shown in Figure 19. In the near term the international factors impacting the wind industry might skew the curve up by as much as another $10/MWh (particularly for developers without established manufacturer relationships), but there will still be around 2,000 GWh of sites that are economic and will be developed in the next 2-5 years.

14.0

Other Technologies

There is a range of other generation options. For various reasons, these options are unlikely to be a significant part of New Zealand's electricity industry over the next 20 years.

14.1 Marine

Marine power generation refers to a range of methods and related technologies for capturing the energy potential of the ocean. These can be grouped into three main areas:

- Tidal barrages. The most established of marine generation technologies, this involves a series of gates that impound incoming high tides and subsequently release the water back through traditional low head hydro turbines at low tide.
- Ocean current. This is a more recent development that involves harnessing the flow of ocean currents through a variety of technologies such as fixed or floating underwater turbines (similar to wind turbines).
- Wave power. This covers a wide range of techniques for converting the motion of waves into energy. Various technologies that are being developed include floating energy converters, oscillating water columns driving air turbines or overtopping devices with low head hydro turbines.

Of the three main areas above, only tidal barrages have been successfully developed commercially. There are limited worldwide locations where tidal ranges and topography combine to make tidal barrages economic.
New Zealand has a relatively small tidal range of 2-3m (Power Projects Ltd, 2005). This makes tidal impoundments and barrages uneconomic compared with overseas sites where tidal ranges are 5-12m (Research Institute for Sustainable Energy, 2006).

Role of Marine Generation

The marine industry is at a similar stage now to the wind industry 25 years ago. The marine industry may be able to speed up the development cycle to achieve comparable performance and LRMCs to wind. However, this is dependent on a number of factors including technology improvements.

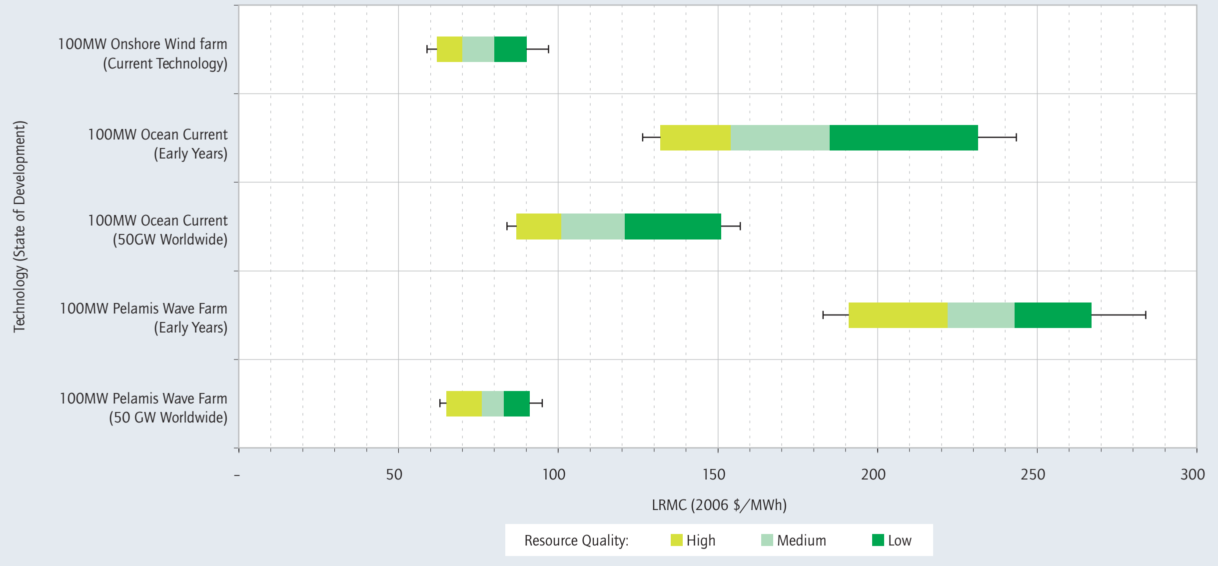
Ocean Current

New Zealand has a number of locations where there are significant tidal currents, driven by the continuous anticlockwise circulation of the tides around the country. The economics of ocean current power will be dependent on finding sites with high average velocities, and appropriate depths (current technologies are designed for 40m). There are limited sites in New Zealand that satisfy all these conditions. The potential for ocean current generation may only be in the order of 1,000-2,000 GWh.

Wave Power

Waves are another huge source of energy potential with an estimated average of 50 kW per metre of wave front on the coasts of New Zealand (PB Power, 2006). With 15,000 km of coastline, New Zealand's wave energy potential is enormous. However, practical factors will limit technically achievable wave generation potential to tens of thousands of GWh.

FIG 21: GENERIC LONG RUN MARGINAL COSTS FOR MARINE VS WIND GENERATION



Issues

A number of issues will need to be resolved before ocean current or wave power technologies can be deployed successfully in New Zealand. These issues include the potential effects on marine life, technology robustness, integration with the electricity system, visual and noise effects and potential conflicts with other users of marine resources.

Economics

We have calculated the LRMCs of two marine generation technologies (Pelamis and underwater floating turbines) based on publicly available information on likely capital costs, capacity factors and operation and maintenance costs. Like other renewable projects, the main economic drivers are resource quality, capital and life-cycle costs. To achieve economies of scale the LRMCs are based on 100 MW installations and have been contrasted with the LRMC range of typical wind sites in New Zealand.

The LRMC results for the marine technologies have been calculated for two different technology commercialisation scenarios:

- Early Years. Marine generation technology is in its first years of commercial deployment.
- 50 GW Worldwide. Marine technology becomes mainstream with an associated reduction in unit costs. For comparison, it took the wind industry 20 years to get from the early years of commercialisation to 50 GW installed worldwide.

The results of the scenario analysis are shown in Figure 21. The coloured bands represent the range of LRMCs in relation to average resource quality; quality includes such factors as ocean current speed or wave energy. The lines on either side of each bar provide a +10/-5 percent sensitivity on capital costs due to factors such as exchange rates and more difficult transmission.

In the early years of commercial production, wave and ocean current generation will be very costly relative to established renewables technologies such as wind, hydro and geothermal. Unless developers wish to be at the bleeding edge of technology adoption, the next several years may be limited to trying to better understand New Zealand's marine resources.

14.2 Biomass

Introduction

Biomass is material of recent biological origin that can be used either as a source of energy or for its chemical components. It includes trees, crops, algae and other plants, as well as agricultural and forest residues. The definition also includes materials found in waste dumps.

In the energy sector, there are three relevant biomass resources:

- woody biomass – wood (including residue and by-products) and dedicated trees and bushes
- landfill gas – from municipal solid waste
- sewerage, animal effluents and agricultural biomass (residues and dedicated crops).

These resources are mainly used as a fuel for heat. They are relatively expensive to transport. Some woody and landfill gas heat plants are cogeneration plants that produce limited amounts of electricity. These two biomass resources are the focus of the remainder of this section.

The East Harbour report "Availabilities and Costs of Renewable Sources of

Energy for Generating Electricity and Heat" discusses biomass in detail (East Harbour Management Services, 2005b). The discussion below summarises the electricity sector implications of biomass.

Woody Biomass

Woody biomass has three main sources: wood residue, wood processing residue and woody crop plantations. In New Zealand, woody biomass electricity generation is fuelled from wood processing residues. There is a 40 MW cogeneration plant at Kinleith and cogeneration plant with a combined capacity of 35.5 MW at Kawerau.

East Harbour has estimated that by 2012 there could be around 285 GWh p.a. electricity generation from woody biomass (10% cost of capital; medium confidence estimate) in the $80-100/MWh range. There could be 1,130 GWh p.a. at higher cost levels. By 2025, the corresponding figures are estimated to be 285 GWh p.a. and 1,625 GWh p.a.

Landfill Gas

East Harbour identifies several existing landfill gas cogeneration facilities:

- Rosedale 21 GWh p.a.
- Greenmount 31 GWh p.a.
- Redvale 8 GWh p.a.
- Silverstream 14 GWh p.a.

Further landfill gas cogeneration units (for example, Awapuni at Palmerston North) were being installed at the time of the East Harbour publication.

East Harbour has estimated there could be around 100 GWh per annum of electricity generation from landfill gas (10 percent cost of capital; medium confidence estimate) in the $40-60/MWh range.

14.3 Cogeneration/Combined Heat and Power

Introduction

Cogeneration is a generic term covering a range of generation technologies and energy sources that are combined to provide both heat and electricity. Scales can range from the kW size, for example household generation, to the MW size, for example Kinleith cogeneration plant. New Zealand currently has 530 MW of cogeneration plant (Ministry of Economic Development, 2006), with fuel sources ranging from natural gas, waste wood biomass, waste heat and to a lesser extent coal and geothermal. These are one form of distributed generation – others such as micro-wind and photovoltaics are discussed in Section 15.

Industrial Scale

During the 1990s a number of industrial sites installed cogeneration plant in the order of 10-50 MW both to provide power and to process steam. Typical sites included dairy factories, pulp and paper plants, wood processors and steel mills. The bulk of these cogeneration plants consist of natural gas or wood waste-fired steam boilers which produce steam for supplying industrial processes such as pulp and paper dryers, drying milk powder or drying timber in kilns, with the surplus going to steam turbines for electricity generation. Smaller-scale sites include swimming pools, hospitals and glasshouses.

The advantages of cogeneration are more efficient energy conversion and steam management, greater security of power supply for the site and reduction of wood waste for sites that use this as a fuel supply. Many of the opportunities for industrial cogeneration have already been taken up, so the remaining potential will be dependent on the availability of natural gas or waste biomass as a fuel supply. MED (Ministry of Economic Development, 2006b) estimates that the remaining potential is in the order of 150 MW, which equates to about 750 GWh per annum.

Residential Scale

Residential scale cogeneration is an area that is still in its infancy, with a number of units being developed, such as the WhisperGen Stirling engine and Ebara Ballard home fuel cell. These are most commonly run on reticulated natural gas, but in the case of the fuel cell there is also a kerosene version. The units generally produce about 1-2 kW of electricity with up to six times that in heat energy, which is used for either heating water or space heating. Because of the relatively large capital cost of these units, both of these technologies are currently aimed at countries with higher electricity costs and greater heating requirements than New Zealand.

Until these technologies transition from niche to mass manufacture, they are likely to be uncompetitive in the New Zealand market. Their competitiveness will also depend on the differential between residential gas price and electricity price being sufficient to make it an economic prospect for the homeowner and the needs of niche market segments such as off-grid homes.

14.4 Nuclear

Introduction

Globally, there are 442 nuclear power plants in 30 countries providing 16 percent of the world's electricity. Most are in developed countries, although the industry has stagnated in Western countries in recent years. Nuclear power has been growing in Asia, with 24 of the last 34 nuclear plants commissioned in the region (IAEA, 2006).

There has been increasing publicity about a revival in the nuclear energy industry. This has stemmed partly from the greenhouse debate over alternative options to thermal electricity generation. For example, President Bush said earlier this year: "[The] United States of America must aggressively move forward with the construction of nuclear power plants."

The IAEA forecasts stronger growth in countries relying on nuclear power, projecting that at least 60 more plants will come online over the next 15 years to help meet global electricity demands. The report estimates that there will be around 430 GW of global nuclear capacity in 2020, up from around 367 GW today.

Nuclear Energy and New Zealand

The main impediment to nuclear power in New Zealand is its social acceptance. However, there are also significant economic and technical issues that make nuclear power an unlikely option for this country. These issues include:

- The use of nuclear energy for electricity generation in New Zealand is prohibited by legislation.
- Nuclear power plants are costly, with significant insurance, capital, operating and decommissioning costs. Nuclear plant is generally regarded as being around twice as expensive as gas-fired plant. Given the other generation options available, nuclear energy is a relatively uneconomic option for New Zealand.
- Nuclear power plants are run at full capacity, and cannot follow demand up or down. They are usually run as base-load plants. This would have significant implications for the way in which other generation plant would be operated in New Zealand.
- The minimum economic scale would be about 600 MW compared with New Zealand's current largest single generation units, which are 385 MW. The cost of providing an additional 200 MW or more of instantaneous spinning reserve or load shedding would be excessive.
- New Zealand would have to purchase fuel overseas, and cannot store waste for any significant period of time due to the lack of a stable geological structure.
- Substantial infrastructure would be required to construct, operate and run a nuclear power station as well as handle fuel and waste. In addition to the physical structures, the associated industry that goes along with nuclear energy would be required – including the training of specialist engineers, management systems and operating expertise in aspects such as fuel transport and waste handling.

Significant research is being conducted into ways of overcoming the issues of scale, safety and waste management with nuclear power plants. However, we believe that it will be at least 10-20 years before these technologies become viable.

15.0

Demand Side Management Initiatives

Some demand side options, particularly energy efficiency initiatives, are an economic and environmentally sustainable approach to meeting New Zealand's demand for energy. These will form part of the solution to meeting New Zealand's future energy needs.

15.1 Introduction

There are clear opportunities for demand side management (DSM) initiatives to form part of New Zealand's energy future. New Zealand already has a history of demand side management; for instance, over one million homes have ripple receivers which can turn on and off hot water load in response to distribution network and transmission congestion.

For the purposes of this report, we consider DSM initiatives to include any opportunity to reduce electricity demand at a distribution network level. These initiatives include:

- measures to reduce energy consumption by employing more efficient technologies
- management and information provision systems designed to provide consumers with the tools and incentives to alter their consumption decisions
- alternative energy sources at the consumer level, including solar and gas
- small-scale distributed generation (DG) projects, connected at either the consumer or distribution network level.

The net economic benefits and market potential of DSM initiatives vary with the specific application. For this report, we have compared the economics of a small selection of DSM options by developing estimates of their LRMCs. Furthermore, where possible, we have estimated the economic market potential of selected DSM options.

We have examined the economics of 12 demand side initiatives, which fall into the following categories:

- energy efficiency measures including compact fluorescent lights (CFLs) and home insulation programmes
- options to utilise alternative primary energy sources, including solar water heating
- small-scale distributed generation, including micro wind turbines and solar photovoltaics.

This list is not exhaustive. It assumes that products perform to their makers specifications and that Resource Consents where necessary are unopposed. However, it represents a short list of "real" DSM alternatives that are in use today.

We have focused primarily on residential level DSM since commercial and industrial DSM already has significant focus from EECA and the Electricity Commission. Economic imperatives already drive many companies to have best-practice energy management, although there is scope for further improvements.

The farming industry is one sector where further energy efficiency can be introduced. An example is energy efficient technologies such as the Varivac milk pump system. These technologies provide a range of benefits; however, farmers must individually work through the economics of these options. There are also opportunities for building energy efficient commercial and residential buildings in New Zealand.

Later in this section we present the Electricity Commission's published estimates of the potential range of total DSM energy savings achievable in New Zealand.

15.2 High-level Review of Demand Side Management Initiatives

Compact Fluorescent Lights

Compact fluorescent lights (CFLs) are a substitute for traditional incandescent light bulbs. They typically require only 20 percent of the electrical energy to produce the same light energy as incandescent bulbs. The cost per unit and market potential for CFLs have been estimated based on the following assumptions:

- a maximum market potential, based on five CFL bulbs per household, for one million houses
- each bulb is on for four hours a day and its usage is consistent with peak demand
- bulb cost is $5 with an expected bulb life of 10,000 hours as stated.

Table 10 shows the installation of CFLs, at an LRMC $9 MWh, is economic when compared with prevailing generation supply costs in the range of $60-80 MWh. This estimated LRMC is consistent with the Electricity Commission's 0.76 c/kWh estimate of the LRMC of CFLs for the Central Canterbury pilot project (Electricity Commission, 2006). The significant difference in LRMCs between CFLs and new generation costs suggests that the implementation of energy efficient lighting programmes across New Zealand will deliver substantial economic benefits.

The peak demand savings presented in Table 10 are also estimated to be substantial. However, these estimates are possibly overly optimistic. The estimated annual energy savings of 584 GWh are equivalent to around 20 percent of the output of a 400 MW combined cycle gas power station, or a 150 MW wind farm with a capacity factor of 45 percent.

This market potential should be reasonably achievable over a 1-2 year timeframe, as the costs of CFLs are low. The efficient lighting programmes established by the Electricity Commission appear to be delivering results in line with these targets.

Solar Water Heating

Solar energy is New Zealand's biggest energy resource. It does not require transportation or any special infrastructure for its use. However, the available quantity of solar energy varies across the country and in general terms is higher in the upper North Island than the lower South Island, and higher on the east coasts than the west coasts of both Islands.

In New Zealand, solar energy is used mostly for water heating. However, the use of this resource is relatively limited. In our view, the maximum market potential of solar water heating (SHW) is likely to restricted by a combination of consumer behaviour or habit and economic considerations. Economic issues with solar water heating include relatively large capital costs, long payback periods and difficulty for energy efficient homeowners to capture a market value for improved efficiency. Some of these issues may be addressed if a national home energy rating scheme was introduced effectively. However, there are also practical constraints such as access to installation technicians.

Our research suggests that the uptake of solar water heating units is most likely to occur in a market segment that includes high income earners. Uptake is also likely to be in areas where solar energy offers higher energy conversion rates, with a general trend towards regions such as the Upper North Island and Nelson, with high sunshine hours and intensity. Solar hot water is a more viable solution when a new dwelling is being built or significant refurbishments are being made and a new water heating system is required. This gives solar water heating units the benefit of being considered on an incremental cost basis.

In 2005, approximately 3,000 solar water heating units were sold across New Zealand (EECA, 2006). This represents a substantial sales increase since 2001 and 2002 when approximately 1,000 units were sold. Case studies conducted by EECA and other analysis completed by the Consumers' Institute suggest that a solar water heating system may save approximately 3,000 kWh per annum for high users (Consumers' Institute, 2001).

We have used the above information to estimate an indicative level of energy

TABLE 10: CFL BULBS – POTENTIAL GWH SAVINGS PER ANNUM AND LRMC

Saver light bulb (W)	20
Normal light bulb (W)	100
Quantity installed per house	5
Number of houses	1,000,000
Peak MW savings	400
Hours per night	4
NZ GWh savings per annum	584
Lifetime hours	10,000
Lifetime years	6.8
Cost per bulb	$5.0
Total cost	$25.0M
Levelised cost	$5.2M
LRMC (c/kWh)	0.9c/kWh
LRMC ($/MWh)	$9/MWh

TABLE 11: SOLAR HOT WATER BASE CASE ASSUMPTION – NZ GWH SAVINGS PER ANNUM

New installations annually[21]	5,000
Annual house load (kWh)	8,000
Hot water contribution to load	50%
Hot water saving	75%
Annual savings per house (kWh)	3,000
NZ GWh savings per annum	**15**

[21] For the purposes of estimating energy savings, we have assumed that, 5,000 units would be installed p.a. from 2007, with a 10 percent compound increase in sales p.a. until the market levels back at 5,000 units p.a. after 10 years.

TABLE 12: SOLAR HOT WATER BASE CASE ASSUMPTION – NZ GWH SAVINGS PER ANNUM

	20-year payback low capital & incremental install cost	20-year payback low capital & full install cost	10-year payback high capital & incremental install cost	10-year payback high capital & full install cost
Cost per install ($)	2,500	4,500	3,500	5,500
Total cost ($)	12,500,000	22,500,000	17,500,500	27,500,000
Levelised cost ($)	1,500,000	2,600,000	2,800,000	4,500,000
LRMC c/kWh	**10**	**17**	**19**	**30**

TABLE 13: MICRO WIND TURBINE MODELS AND LRMCS

Micro Turbine Type	Cost per kWh ($)	Total output p.a. (kWh)[22]	Rated output (kW)
Rutland 503	1.12	175	0.1
Rutland FM 910-3	0.32	438	0.2
Condor	0.32	438	0.2
Rutland 913	0.47	876	0.4
Green Power 1 kW	0.39	2,190	1.0
Soma 1000 (Reid Technology)	0.68	2,190	1.0
Green Power 500 W	1.07	2,190	0.5
WindSwift	0.40	3,285	1.5
Skystream	0.43	3,942	1.8
Unitron Whisper 175 3.3 kW	0.40	7,227	3.3
Breeze 5000	0.48	10,950	5.0
Green Power 10 kW	0.29	21,900	10.0
Bergey Excel 10 kW	0.30	21,900	10.0
Green Power 20 kW	0.25	43,800	20.0

savings per unit and potential national energy savings per annum. This estimate is summarised in Table 11.

In terms of avoided energy generation, if 5,000 solar hot water units were installed per annum, the energy savings would be approximately 15 GWh per annum. This is substantially lower than the savings delivered by CFL installation.

The two main considerations for calculating LRMCs for solar hot water systems are the capital cost of the system and the expected payback period. The economics also vary depending on whether the system is a new installation (for example, in a new house or to replace a failed water system) or an incremental system. We have estimated an LRMC or unit cost range for solar hot water by varying these key inputs. This range is summarised in Table 12.

Table 12 shows that solar water heating LRMCs may vary from 30 c/kWh ($300/MWh) for a higher capital cost of $5,500, assuming a 10-year payback period, down to 10 c/kWh ($100/MWh) for a low capital and incremental cost installation, for example a new house or major refurbishment where a new water heating system is required, along with a 20-year payback.

It should be noted that even higher LRMCs would be expected in areas of low solar energy, in particular the south and west coasts of the South Island.

Solar water heating systems are likely to be cost effective when compared with a delivered energy price of 17-20 c/kWh in situations where:

- solar energy levels are highest
- consumers are faced with a marginal cost decision such as when replacing existing water heating systems or constructing new dwellings
- consumers are likely to remain in the same dwelling for a reasonable period of time, at least 10 years.

However these higher delivered electricity variable rates faced by consumers include a component of fixed transmission and distribution charges. If distributed generation technologies were to increase on a large scale, the structure of electricity tariffs would probably be altered so that fixed costs were recouped: the avoidable, variable component would be lower and the fixed charge would be higher. Such a change in retail tariffs would significantly reduce the economic merit of these options. Furthermore, in a national benefit sense, the appropriate rate to assess solar hot water against is the energy only cost component of delivered electricity.

Micro Wind Turbines

Commercially available micro wind turbines range in scale from a few hundred watts up to 20 kW size units. Information gathered from potential large-scale, grid connected, wind farm sites shows that wind speed in New Zealand is significant and offers some of the best wind to energy conversion prospects per installed capacity in the world. Micro wind turbines aim to capture this wind energy on a much smaller scale with connections at either residential, including rural applications, or commercial levels.

We have reviewed the micro wind turbines listed in Table 13 to establish their LRMCs and to assess their economic potential.

In terms of the likely market for these products, there are similarities between the micro wind market and the solar water heating market, due particularly to the capital costs associated with the turbines. The highest uptake for micro

[22] The total output of all micro wind turbines is based on an average capacity factor of 25 percent.

turbines is likely to be in a market segment that includes high income earners, and is located in areas where wind energy offers higher energy conversion rates. Micro turbines are also likely to have higher uptake in rural or lifestyle locations, where consenting requirements and visual objections from neighbours are likely to be less than in urban areas.

It should also be noted that none of the turbines assessed can produce electricity at lower rates than grid connected generation and in a national benefit sense all appear to be uneconomic.

The economics of micro wind turbines improve as the scale increases. This is consistent with Meridian Energy's experience with grid connected wind farms. However, once a micro wind farm becomes a net injector of electricity, its cost effectiveness from an installer's perspective changes from being based on avoiding a higher (18-20 c/kWh) variable electricity tariff to a substantially lower (6-8 c/kWh) energy only sales price.

We do not consider that micro wind turbines will provide a material contribution to demand reduction for a number of years. In fact, micro wind turbine production does not even feature in Figure 23. This conclusion is based on the high capital costs and unit price of the technology and the range of practical issues associated with installation and ongoing maintenance of the units.

Other Energy Efficiency Measures

Research suggests that there are a number of other energy efficiency measures that provide electricity savings between the cost of CFLs and solar water heating and micro wind generation. These measures include improving home insulation properties and improving motor efficiencies, for example in refrigeration and other appliance and industrial applications.

We have sourced information from the Electricity Commission's website on pilot efficiency programmes to determine the approximate LRMCs of home insulation as an example of one of a number of possible energy efficiency measures that are likely to deliver national benefits. This is presented in Figure 22 (Electricity Commission, 2006b).

Photovoltaics

Harnessing solar energy by converting it to electricity with photovoltaic (PV) cells is a fairly well-established practice. However, the high manufacturing costs and low power density of this technology mean that it is not economic for most consumers connected to the grid. Photovoltaics may become economic in remote applications, for example new rural homes, when the cost of connecting to the nearest power line is in the order of $20,000 or more. In these cases, the home owner also needs to install batteries and have back-up power supplies such as diesel generators and more expensive low-energy devices.

At current costs, the LRMC for 5 kW (about 40m^2 of panels or nearly half the average roof space) of PV with inverter systems is around $950/MWh (95c/kWh) for the best New Zealand solar resource (about 13 percent capacity factor). This would produce up to 5,700 kWh per annum, about 70 percent of average household usage.

PV would require future technological breakthroughs to reduce capital cost by around 80 percent to make it an economic demand side option. The ability to scale up production of silicon-based PV has been limited by shortages of refined silicon. New materials, such as titanium-dioxide plastic solar cells, are being developed that may reduce the costs significantly, however efficiency will be lower than silicon based PV (PB Power, 2006). Accordingly, we have assumed that, in the time span considered in this report, PV will not make a significant impact on demand growth.

15.3 Summary

There are a number of DSM initiatives that are economic when compared with the LRMC of electricity supply from large-scale power plants. The implementation of economic DSM options provides the opportunity to achieve substantial national benefits and reduce the requirement for new generation construction to meet ongoing demand growth.

In general terms, energy efficiency measures provide the highest degree of national benefit as many projects can be delivered below the LRMC of supply. Figure 22 summarises the high-level LRMC comparison of the DSM initiatives investigated.

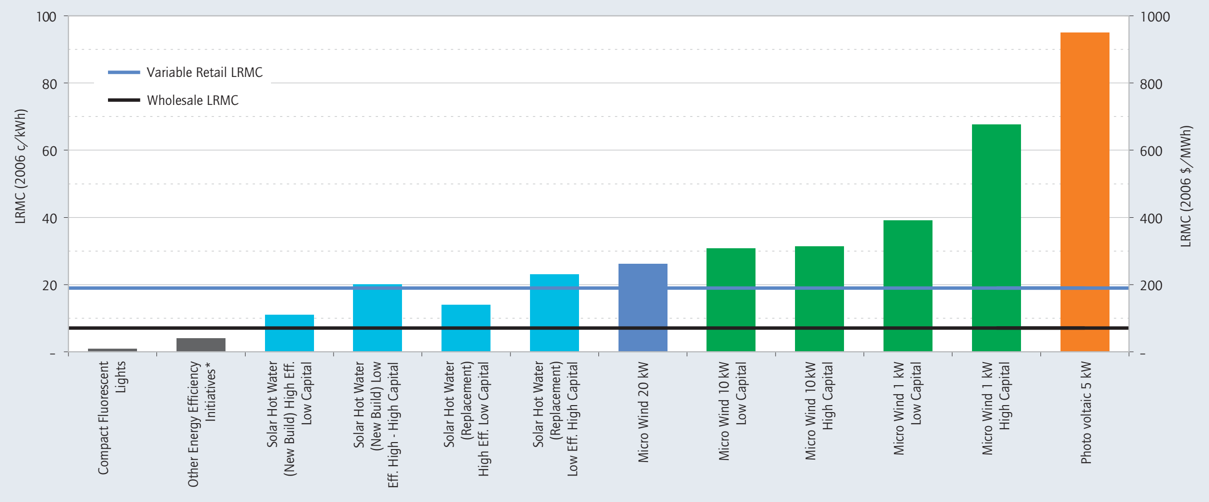
In Figure 23 we have graphed an estimate of the market potential of the economic DSM options considered previously (because the potential of micro wind is negligible it does not show on the graph). In this same figure we also show levels of DSM energy savings that may be possible as published in recent demand side scenarios prepared for the Electricity Commission (Electricity Commission, 2006c). This gives an idea of the potential range for DSM options to reduce the demand for electricity sourced from the grid.

Although there are several DSM options that may make a contribution to meeting New Zealand's energy requirements, Figure 23 shows that there is still a substantial energy balance gap that needs to be met from large-scale power generation sources. For example, the Electricity Commission has estimated that the likely contribution of DSM is around 1,800 GWh. Based on this estimate and a 1.5 percent demand growth rate, additional generation of over 13,000 GWh would be required by 2026.

It should also be noted that while a number of demand side initiatives are economic, their uptake to date has been relatively limited. This outcome has been driven by a combination of:

- Consumer behaviour and habits. Significant effort is required by consumers to incorporate many of the DSM initiatives.
- Lack of information about electricity consumption. The adoption of smart

FIG 22: **HIGH LEVEL DSM LRMC COMPARISON**



* Note – "Other Energy Efficiency Initiatives" includes household insulation and motor efficiency improvements. LRMCs were sourced from the Electricity Commission's pilot programme publications.

FIG 23: **MEDIUM DEMAND GROWTH WITH DSM ENERGY SAVINGS, 2007-2026**

metering technology in New Zealand is expected to improve this situation.

- Lack of practical implementation programmes targeted at delivering specific results. The Electricity Commission's CFL programme is an exception to this.
- Lack of policies to reset behaviours and habits and to require compliance with minimum standards, for example building codes.

Some DSM initiatives appear cost effective to consumers because they provide a means of avoiding the relatively high variable cost of delivered electricity. However these high variable rates include a component of fixed transmission and distribution charges.

If distributed generation technologies were to increase on a large scale, the structure of electricity tariffs would need to be altered so that fixed costs are recouped. Accordingly, comparison with current retail tariffs may be somewhat misleading.

APPENDIX

Economics of the New Zealand Wholesale Electricity Market

Functions of the Market

The New Zealand wholesale electricity market has been designed to perform the following broad functions:

- Match the cost of supply, including generation and transmission costs, with consumers' willingness to pay to determine the amount of electricity supplied and its price. This outcome is referred to as "allocative efficiency" in economics.
- Provide incentives for the generation sector to minimise the cost of electricity supply at any point in time, subject to transmission capacity availability. Under this outcome, generation (or load adjustments) is dispatched efficiently and electricity is produced by the "lowest cost" suppliers. The concept of lowest cost is discussed below. This outcome is known as "productive efficiency".
- Provide appropriate investment signals, enabling efficient plant investment to be made – including the appropriate form (including fuel type, size and location) and timing of investment. This is referred to as "dynamic efficiency".

  These principles are all fine; the questions are whether the wholesale market achieves these outcomes and what the relevant mechanisms are. We focus on two elements of New Zealand's wholesale market:
- How are prices established? Given the wholesale market is predominantly supply driven, with demand being inelastic (particularly in the short term), the focus of this question is on how the generation sector offers into the market. Is this done efficiently?
- Does the market lead to sufficient lowest-cost generation investment over the longer term? In terms of the previous discussion, this point can be rephrased as: "Is the wholesale electricity market dynamically efficient?" This is often referred to as the "electricity security of supply" issue.

Prices in the Wholesale Electricity Market

Marginal Cost Pricing

The New Zealand wholesale electricity market takes the form of a uniform price auction market. In a uniform price auction (sometimes referred to as a single price auction) suppliers make offers on supplying various quantities of product. Every winning offer receives the same price, which is the price that clears the market. This is the price of the marginal unit. In particular, offers that are lower than the market clearing offer are paid the price of the market clearing offer.

In a workably competitive market, a uniform price auction encourages parties to offer relative to the short run marginal cost (SRMC) of their plant. If a party offers higher than marginal cost, it risks the plant not being dispatched and so losing an opportunity for the plant to earn a return. If the party offers lower, it will not cover short run operating costs. Following this logic, the system price should be related to the industry's marginal cost of production.

In the long term, these plants must cover their long run marginal cost (LRMC) as well as their SRMC; otherwise, firms would not earn an economic return on their capital. A uniform price auction market enables lower SRMC plant (termed "inframarginal plant") to earn revenue higher than their SRMC. The difference at any point in time depends on which generation plant is clearing the market. This difference is termed "scarcity or inframarginal rent". These scarcity rents enable generation plant to cover their LRMC (see, for instance, Stoft, 2002).

These scarcity rents enable the wholesale market to include the various forms of generation plant necessary to supply demand at any point in time, including base-load plant (high capital costs, low operating costs), mid-merit plant (moderate capital costs, higher operating costs) and peaking plant (lowest capital costs, highest operating costs).

Defining Marginal Cost

It is obvious from the previous discussion that the concept of marginal cost is integral to the function of the wholesale electricity market (actually, like any other market). So, it is important that marginal cost is clearly understood. Marginal cost (in the short and long run) includes the supplier's marginal product cost, and opportunity costs. An opportunity cost is the value of other opportunities foregone.

In New Zealand's wholesale electricity market there is a variety of opportunity costs that form part of various generators' SRMCs and affect their bidding in the market (see Counsell et al, 2006). The clearest and most significant example is storage in the hydro lakes. Putting aside inflows into the lakes, generating electricity from the lakes today implies that less resource is available for generating electricity tomorrow. So, even though the current price may be above a hydro generator's variable cost (which is close to zero), the generator has an incentive to bid at least the opportunity cost based on its forecast of where future prices may be going. This opportunity cost of water resource is referred to as the "water value". Estimation of this value is complicated by the fact that inflows into the hydro catchments are uncertain and relatively unpredictable. The water values used also incorporate this risk element.

Though hydro-related opportunity cost is the most obvious example, there are other opportunity costs in the wholesale market that can significantly affect its operation. Coal storage and delivery also have an opportunity cost element. For example, Huntly Power Station has the choice of using its stockpile today or tomorrow. The size of the stockpile makes this opportunity cost relatively muted at various times, though the fact that thermal power plant is used to offset hydro variability means that the opportunity cost is a relevant consideration. Similarly, the nature of gas contracts and the physical properties of gas fields mean that gas-fired plant may have significant opportunity costs. A further example of opportunity cost is the impact of resource restrictions on plant usage. For example, Huntly Power Station's generation levels are affected over summer by a river consent restriction that limits the temperature downstream of the station. There are various operational strategies that may be employed to stay within this constraint.

Investment in Generation

From the previous discussion, there are incentives to invest in generation if the inframarginal rents of plant exceed those required to earn their LRMC. For a growing economy like New Zealand a more important issue is whether there are incentives to invest to meet increasing demand for electricity.

New Zealand's electricity demand is forecast to grow at around 2 percent per annum. The generation sector should respond by building new plant. Furthermore, following the earlier discussion on dynamic efficiency, this new capacity should be the lowest-cost plant (that is, the lowest LRMC) for the roles it will be performing. In this report, we have taken the LRMC of a generation project to be equal to the (levelised) unit cost of the project. This unit cost is the price needed to recover all costs of an investment over its economic life.

There is plenty of evidence that generation capacity is being built or contemplated to meet rising demand. Currently planned or committed projects are included in Part A of this report. Furthermore it appears that this new investment tends to be the least-cost generation solution for meeting this demand. For instance, wind farms with quality wind resources are being built. A brownfields coal plant (Marsden B) is being proposed ahead of greenfields coal opportunities.

Though the market is responding adequately to demand increases, a related issue is whether there are sufficient incentives for reserve generation. In a properly functioning market, these incentives should exist. In times of tight generation supply (in New Zealand, this situation is usually caused by hydrology patterns but unexpected plant outages, transmission constraints and unexpected levels of demand may also lead to tight supply conditions), the wholesale price should respond by spiking relatively high. These price events enable reserve plant to earn an economic return. However, various factors may temper these price events so that they are not sufficient for reserve plant to be economic. First, these events are relatively uncertain so determining the economic viability of this form of plant is more difficult. Second, the lack of real-time metering makes a demand side response to high prices relatively muted (especially in the residential sector). Related to this point, all consumers place a value on electricity and particularly the value of lost load. The inability for consumers to signal this value affects this form of generation the most. Third, government intervention during these events and regulatory uncertainty increases uncertainty around the nature of these events. The government's investment in the Whirinaki plant, together with its operation rules, further muddies the incentives to build reserve generation.

Transmission

An adequate transmission network is critical for the proper functioning of a wholesale electricity market. As an extreme, if New Zealand had no transmission network, electricity generation would have to be co-located with distribution networks. There would be a multitude of local markets that would mostly be served by monopolies. Renewables generation would not be built because the resource for this plant is typically not located close to demand (West Wind being an obvious exception). Higher-cost forms of plant such as oil-fired plant would need to be built.

Clearly, these outcomes are not reasonable; transmission is an infrastructure investment vital for the functioning of any electricity sector. However, if investment in infrastructure is not sufficient, lesser forms of these outcomes may manifest. For example, there is potential for some markets to become regionalised, particularly at peak periods with higher costs of electricity supply. Some otherwise economic generation plant may not be built.

This point is made in Joskow (2002): "... unregulated wholesale electricity markets work best when transmission congestion and constraints do not place significant limitations on the number of generators which can compete to serve demand and provide reliability to the network at specific locations." Joskow goes on to suggest that in such an industry, where generation and transmission decisions are made independently, successful wholesale markets require "over-investment" (compared with a perfectly coordinated, centrally planned Strawman) in transmission capacity to create a truly competitive market. The logic behind this idea is reasonably intuitive given that transmission is the conduit for connecting various market participants. At a broad level, this approach is also sensible from a cost perspective, given that the investment costs of transmission are an order of magnitude smaller than those of generation.

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Glossary

Acreage	Land or offshore area leased or licensed for oil and gas exploration and production.
Base-load plant	A base-load plant operates almost all the time. It uses low-cost fuel and is more efficient at full load.
Binary geothermal plant	In a binary geothermal plant, hot geothermal liquid vaporises a secondary working fluid, which then drives a turbine.
Biomass	Material of recent biological origin that can be used as a source of energy or for its chemical components.
Brownfields project	Development of a plant or resource that is abandoned or underused or has existing supporting infrastructure.
Capacity factor	The amount of electricity a facility generates in one year divided by the total amount it could potentially generate if it ran at full capacity.
Carbon sequestration	The process of removing additional carbon from the atmosphere.
CCGT	Combined cycle gas turbine. A CCGT consists of one or more gas turbine generators combined with a heat-recovery system used to power a steam turbine.
CNG	Compressed natural gas.
Compact fluorescent light	CFL. A type of fluorescent lamp that screws into a normal light bulb socket. In comparison to the usual incandescent light bulbs, CFLs have a longer-rated life and use less electricity.
Demand side management	Utilisation by electricity consumers (the "demand side") of various options that reduce the demand for electricity supplied on the national grid. These options include energy efficiency initiatives, which reduce the demand for electricity, through to micro-generation and use of other energy such as solar.
Discount rate	A rate of return used to convert an economic cash flow in the future into present value.
Distributed generation	Typically small-scale electricity generation that is connected to distribution networks rather than directly to the national transmission system.
Embedded generation	See distributed generation.
FGD	Flue gas desulphurisation. A technology that employs a sorbent, usually lime or limestone, to remove sulphur dioxide from the gases produced by burning fossil fuels. Flue gas desulphurisation is currently state-of-the art technology for major emitters like thermal power plants.
Gigajoule	GJ. 1x 10^9 joules. A joule is a unit of energy. Commonly used in the New Zealand gas industry as a measure of the volume of gas. 1 GJ = 278 kWh.
GWh	Giga Watt hour. A measure of energy production. One million kWh.
Greenfields project	Completely new plant.
HVDC	High-voltage direct current transmission system. Used for the bulk transmission of electricity. Relative to AC transmission, HVDC transmission has the advantage of lower transmission losses. The New Zealand HVDC transmission network runs from Benmore to Haywards.
Hydrology	The dynamic processes of water within an environment, including the sources, timing, amount and direction of water movement.

IGCC	Integrated Gasification Combined Cycle. Electricity generation plant which produces synthesis gas (syngas) converted from fossil fuel (including coal) and then burns this gas by combined cycle.
kW	Kilo Watt. A measure of power, 1,000 watts.
kWh	Kilo Watt hour. A measure of energy production or consumption. A 1 kW machine (for example, a heater) running for one hour consumes 1 kWh of electrical energy.
Kyoto Protocol	The Kyoto Protocol was adopted at the Third Session of the Conference of the Parties (COP) to the UN Framework Convention on Climate Change (UNFCCC) in 1997 in Kyoto, Japan. It contains legally binding commitments for a number of "Annex B" countries to reduce their anthropogenic ("man-made") emissions of greenhouse gases (GHG) in the commitment period 2008-2012. New Zealand's commitment is to have 2012 GHG emissions at the same level as they were in 1990.
kV	Kilovolt. A unit of pressure, or push, of an electric current; 1,000 volts. The measure is used to express the amount of electric force carried through a high-voltage transmission line.
Levelised unit cost	Levelised unit cost is the price needed to recover all costs of an investment over its economic life. It is determined by finding the price that sets the sum of all future discounted cash flows (net present value, or NPV) to zero. In this report levelised unit cost is taken to be equal to LRMC.
Lignite	The lowest rank of coal, often referred to as brown coal, used almost exclusively as fuel for steam-electric power generation. It is brownish-black and has a high inherent moisture content and a low heat content.
LNG	Liquefied natural gas. LNG is the liquid form of natural gas – cooled down to -161°C and maintained at atmospheric pressure. Liquefaction of the gas enables it to be transported at significantly lower costs – the process reduces the gases' volume to approximately 1/600th of its original volume.
Load factor	Ratio of the amount of electricity used during a specific time period to the maximum possible during that period, expressed as a percentage.
LRMC	Long run marginal cost. LRMC is the cost of producing one extra unit (or one less) of output when all factors of production are variable. In contrast to SRMC this cost definition includes the capital investment required to deliver the output. In this report, (levelised) unit cost is taken to be equal to LRMC.
Micro-generation	Small-sized generation.
Mid-merit plant	Mid-merit plant operates on shoulder periods so they can cycle up and down gradually. They are efficient but may use high-cost fuels.
MW	Mega Watt. A measure of power, one million watts. Amongst other things, used to define the capacity of generation plant.
MWh	Mega Watt hour (1,000 kWh). A measure of energy production. A 1 MW power-generating unit running for one hour produces 1 MWh of electrical energy.
OCGT	Open cycle gas turbine. An OCGT plant has low capital costs, but high running costs. It is usually operated as peaking or reserve plant.
Peaking plant	A peaking plant operates comparatively infrequently. It has high fuel costs and can cycle on and off. The plant is reasonably efficient under low load conditions. A peaking plant is typically an oil- or gas-fired OCGT.

Petajoule	PJ. 1x 10^{15} joules. A joule is a unit of energy. Commonly used in the New Zealand gas industry as a measure of the volume of energy. 1 PJ = 278 GWh.
PM-10	An air pollutant consisting of small particles with an aerodynamic diameter less than or equal to a nominal 10 microns (about 1/7 the diameter of a single human hair).
Prospectivity	A term used in the petroleum industry relating to the exploration "attractiveness" of a country, area or basin.
RMA	Resource Management Act, 1991.
SRMC	Short run marginal cost. SRMC is cost of producing one extra unit (or one less) of output in the short run. In this definition of cost, capital costs are excluded since these costs are sunk in the short run.
Sub-bituminous coal	Young black coal with high moisture content of between 15 and 40 percent by weight.
System Operator	Responsible for the real-time operation of a power system.
Thermal generation plant	A plant that converts heat energy into electrical energy. The heat in thermal plants is produced from a number of sources such as coal, oil, gas or nuclear fuel.
Transmission	A network that transports large quantities of energy. In the electricity industry, a transmission network includes high-voltage lines, transformers and switches used to move electrical power from generators to the distribution system. In the gas industry, a transmission network involves large-diameter gas pipelines and associated infrastructure such as compressors.
TWh	Tera Watt hour. A measure of energy production. One billion kWh.
Unit Cost	See Levelised unit cost.
Wholesale electricity	Wholesale electricity is supplied by generators and purchased by electricity retailers and some major electricity users.