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NEW ZEALAND CENTRE FOR ADVANCED ENGINEERING

An Analysis of the Effect of Renewable Energy Targets in the Electricity Sector on the New Zealand Gas Industry

February 2008

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Association of New Zealand

Prepared by:

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Advanced Engineering

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EXECUTIVE SUMMARY

CAENZ is of the view that the New Zealand Energy Strategy, and in particular the moratorium on baseload thermal electricity generation plants and the 90% renewables target, should more fully recognise the important contribution natural gas makes to both primary energy supply and the secure generation of electricity in New Zealand. It is also concerned that the 90% renewables target will have a detrimental effect on the sustainability of an integrated domestic gas industry and that government, whilst evaluating its policy alternatives, did not fully or accurately take into account the impact and consequences of policy on the gas industry.

Consequently, CAENZ has reviewed the impact of this policy using the government's own analytical tools for the electricity sector and by undertaking a detailed review of the petroleum exploration and production industry. The principal conclusions CAENZ has drawn from this review and analysis are summarized in the following paragraphs.

1 Electricity Sector

The renewables policy exposes the electricity system to increased costs, increased uncertainty and increases the risks to electricity security of supply. Reducing the contribution of thermal generation to 10% of electricity output represents a significant reversal from current trends, raising significant issues of system security and for the timely availability of thermal fuels to back up the intermittent nature of wind energy. Gas should be the thermal fuel of choice because of its relatively low carbon dioxide emissions.

- The moratorium on baseload thermal electricity generation plants and the 90% renewables target policy will result in significantly increased installed generating capacity at a correspondingly high capital cost, particularly in relation to a policy environment where gas use is unconstrained.
- Electricity prices will be more volatile and will increase by at least 15%, excluding additional costs of transmission, with increases in excess of 40-50%, in real terms, within 15-20 years being plausible.
- The 90 per cent renewables target will require a high proportion of wind generation capacity to be installed. This raises significant issues of system security, which have not yet been adequately investigated and are, therefore, not well understood.
- Increased wind capacity will require greater stand-by capacity such as more spinning reserve to cover sudden reductions of wind generation output. This will result in additional costs for back-up and stand-by generation facilities and other requirements such as frequency and voltage control. These have not been fully costed into the assessments made by government.
- Because of the remote location and intermittent nature of much of the potential renewables generating capacity, significant additions will be necessary to the electricity transmission system. The associated costs have not been included in the government's analysis nor have the tools been sufficiently developed to assess them adequately.
- A shortfall in gas availability induced by policy will result in gas prices rising, increasing the possibility of coal out-competing gas, notably at the Huntly power station, with consequent increases in carbon dioxide emissions.

2 Gas Sector

The government's own analysis indicates that gas use for electricity generation will fall from a current level of 60 PJ pa to 40 PJ pa, resulting in an overall reduction in the New Zealand gas market. CAENZ's review of the past performance of gas sector indicates this will have a negative impact on investment in gas resource exploration and development activities, reducing the likelihood that new gas resources will be found to service existing gas markets and to provide the electricity generation back-up implicit in the renewables policy.

- Continuity of market opportunities for gas is a primary incentive for the on-going investment in exploration and development activities necessary to provide new gas reserves. A reduction in gas demand resulting from the renewables policy will break this continuity, leading to a reduction in gas exploration and development investment, particularly in the short to medium term. Once downsized, the industry will take time to recover.

- Existing gas reserves are expected to decline from about 2017. It is probable that these reserves can be supplemented by new reserves in incremental or new fields to maintain a continuity of supply beyond this time provided that adequate incentives are available to the gas industry. Industry has shown that it can develop these reserves in a timely fashion since the decline of the Maui field, which is at odds with the government's pessimistic view of the generation of future gas reserves.
- A shortfall in gas availability induced by policy will result in gas prices rising, opening the possibility of LNG imports as a longer term solution – exactly counter to the intent of present policy settings. LNG importation represents a threat to the domestic exploration and production industry, as it would potentially close out a very significant proportion of the New Zealand gas market. This is an important public policy debate.
- The availability of gas as a back-up to renewables electricity generation may be problematic in a declining gas market. Gas sector economics do not support holding large amounts of gas for stand-by purposes unless complemented by a strong base market for gas.
- The 90% renewables policy will result in one of the existing three CCGT stations becoming surplus to requirements, a case of enforced stranding of assets.

3 Government Analysis

CAENZ's review of the case studies used in the analysis of the government's 90 per cent renewables target reveals a number of inconsistencies and omissions. These allow an optimistic case for maximising the renewables contribution to electricity generation to be presented when cheaper and more secure forms of electricity generation, such as from natural gas, are available.

- The moratorium on new thermal generation has been put in place to pre-empt the uptake of new thermal plant instead of renewables generating capacity. Government places a low probability on this happening in practice whilst the case studies show that thermal generation is a clear least-cost option.
- Government analysis of cases with lower levels of renewables uptake includes major coal use, resulting in disproportionately high levels of carbon emissions which may in practice be mitigated by gas substitution.
- The 90% renewables case includes significant expansion of geothermal capacity, which has significant carbon emissions, and coal-fired plants with carbon sequestration, which brings into question the feasibility of reaching the 90% target.
- The government's case for an increased renewables target is based on low electricity demand growth assumptions that are, in turn, based on economic growth projections averaging around 2.3% pa. These assumptions will understate the additional costs of the renewables policy.
- Additional electricity system back-up and stand-by generation facilities and voltage control have not been fully costed into any of the current assessments.
- Transmission grid enhancements and new construction to enable intermittent renewables have not been included in the economic analysis undertaken by government.
- The energy strategy does not sufficiently examine the impact the new policy will have on the gas industry and its implicit back-up role. CAENZ's review suggests that the policy puts this role at risk.

4 General Conclusions

CAENZ's review of the policy reveals a number of costs and risks to energy sector security and the gas industry in particular that have not been adequately scrutinized by government. The policy has the potential to have a negative impact on broader primary energy supply and increases risks to energy security of supply. It is important that legislation at least be deferred until such time as a complete analysis of the full impacts of the policy has been undertaken and appropriate legislative settings made.

- The focus of the policy is on electricity generation. Gas is also a significant direct supplier to the wider industrial, commercial and residential markets and a negative impact on gas reserve development by new policy will result in a shift to coal or oil in these markets. Such a shift will result in increased carbon dioxide emissions and increases the risks to energy security of supply. Both of these outcomes are at odds with the objectives of the policy.
- The gas sector is a significant and proven contributor to New Zealand's economic base and its future is worthy of important public policy debate and should not be compromised by an aspirational 90% target for renewables technologies which are unproven on the scale envisaged in New Zealand.
- By implementing the 90% renewables target, government runs the risk of penalising energy consumers through higher energy prices than might be anticipated elsewhere in the world.
- Current government energy policy thus seems likely to reduce the size of the New Zealand gas market, increase energy prices and ultimately reduce energy security. There are other options.

1 INTRODUCTION

The focus of the New Zealand Energy Strategy published in 2007 has been the promotion of renewable energy as a means of reducing this country's greenhouse gas emissions. This policy has been extended into law with the Climate Change (Emissions Trading and Renewable Preference) Bill, which introduces a greenhouse gas emissions trading scheme and amends the Electricity Act 1992 by placing a 10-year restriction on new fossil-fuelled thermal generation and placing a target for renewable electricity generation of 90 per cent of New Zealand's electricity generation by 2025. Exemptions will be allowed to ensure the security of New Zealand's electricity supply.

Indigenous thermal fuels such as natural gas are given scant recognition in this policy and primarily are seen as providing a transitional role in the move to renewable fuels or to maintain security of energy supply in the event of a shortfall or failure in renewables energy supply. However, the energy strategy does not have a parallel strategy to ensure that thermal fuels will be available to fill such a shortfall, resulting in uncertainty and little incentive for suppliers to continue with the investment necessary to maintain their businesses. This creates a new vulnerability in the New Zealand energy market.

CAENZ is of the view that the energy strategy should more fully recognise the important contribution natural gas makes to both primary energy supply and the secure generation of electricity in New Zealand. It is also concerned that the 90% renewables target will have a detrimental effect on the sustainability of an integrated domestic gas industry and that government, whilst evaluating its policy alternatives, did not fully or accurately take into account the impact and consequences of policy on the gas industry.

Natural gas presents a unique combination of attributes in that it is produced from indigenous resources, has a highly reliable delivery infrastructure and physical properties that permit high levels of energy intensity and delivery with low levels of pollutants. As a fossil fuel, gas emits carbon dioxide, but at lower rates than coal or oil products, particularly when used in high thermal efficiency plant such as combined cycle gas turbines (CCGT) for electricity generation.

The report that follows is in response to these concerns. It was commissioned by the Petroleum Exploration and Production Association of New Zealand because of its shared concern that the importance of natural gas to New Zealand's economy was not adequately considered in the development of the new policy.

2 APPROACH

This report examines the impact of the moratorium and 90% renewables target contained in the Climate Change Bill on the demand for natural gas for electricity generation and the likely consequences for the gas exploration and production industry. It has been undertaken in two parts:

- An assessment of the impact of the renewables policy on gas use for electricity generation. This has been done by reviewing a series of case studies carried out by government whilst analysing the 90% renewables policy impacts. It investigates the impacts on the quantity and nature of gas consumption and provides comment on the assumptions used by government in its analysis.
- An assessment of the impact of the change in gas consumption in electricity generation on the gas exploration and production industry. This is a largely qualitative review of gas markets, gas reserves available and the ability of and conditions under which the gas industry can add to those reserves and their subsequent production.

Security of energy supply has been identified as a key issue in this examination, in the context of both a secure and stable electricity system and the contribution natural gas has made to the supply of primary energy in New Zealand. Whilst the Climate Change Bill acknowledges the importance of energy security in its exclusion provisions, this report discusses in detail the risks associated with energy security brought about by the targets contained in the Bill and which, in the view of CAENZ, have been inadequately analysed by government during the consideration of the targets.

2.1 Climate Change (Emissions Trading and Renewable Preference) Bill

The ten year moratorium on new base load thermal electricity generation capacity is contained in the Climate Change (Emissions Trading and Renewable Preference) Bill. The first part of the Bill amends the Climate Change Response Act 2002 to introduce a greenhouse gas emissions trading scheme, whilst the second part puts into effect the government's preference for renewable energy contained in the New Zealand Energy Strategy (NZES) by inserting a new Part 6A into the Electricity Act, 1992. Its objectives are:

- A target for renewable electricity generation of 90 per cent of New Zealand's electricity generation by 2025.
- A clear preference that all new electricity be renewable, which is effected in the Bill by providing for a 10-year restriction on new fossil-fuelled thermal generation, "except to the extent required to ensure the security of New Zealand's electricity supply".

Under the Bill, the moratorium on thermal generation will be enforced by law whereas the attainment of 90 per cent of electricity generation by renewable resources is an aspirational target.

Government considers there is a need to impose this regulation as the ETS does not necessarily preclude the construction of thermal power stations. It recognises the possibility that gas could be priced so that gas-fired power plants would be built in preference to renewables technology, but ascribes a low probability to gas uptake without the moratorium.

Security of electricity supply is a key exemption to the moratorium despite the government's belief that "firm baseload support, additional energy supply during dry years, and necessary ancillary support for voltage and frequency" can be maintained for the foreseeable future through "increased use of new renewable energy sources along with existing renewable and fossil fuel generation". Criteria to be used for these exemptions have not been fully defined.

The importation of LNG is perceived by government as a risk. Government believes that the moratorium, by resulting in less gas plant capacity being constructed, will reduce the possibility that LNG will be imported into New Zealand. In the government's opinion, this is a favourable outcome as LNG importation will tend to uphold the position of fossil fuels in the primary energy mix as well as reduce the demand for local exploration.

2.2 Electricity Sector Scenarios Analysed

This study investigated three electricity sector scenarios used by the Electricity Commission plus one developed by CAENZ to investigate the analysis behind government policy settings and to examine the consequences of government policies:

- High Gas Availability: Gas use was assumed to be unconstrained and held at the relatively low price of $7/GJ, plus a carbon charge of $15/tonne CO_2, resulting in the construction of three additional CCGT plants. Coal use also was unconstrained resulting in high levels of carbon dioxide emissions.
- Base Case Renewables: This case represented government's view of the electricity sector until the 90% target was adopted. Renewables usage was set at a 75% maximum target by 2025 to be consistent with current usage and gas prices assumed to rise from $5.5/GJ to a ceiling of $10/GJ in 2020 with the carbon charge rising to $40/tonne. With a coal price set at $4/GJ, the Huntly power station was assumed to run on coal until 2030, resulting in high emissions.
- 90% Renewables by 2025: Using the same settings as the base case, this case described the new policy by imposing a 90% renewables minimum target. This forces the closure of one of the three existing CCGT power plants and also that of the Huntly power station with significant reductions in carbon dioxide emissions.
- Coal Retirement Scenario: A fourth scenario was developed by CAENZ to investigate a relatively high gas use case with low carbon emissions. The Huntly power station was retired to standby operation in 2016 and replaced by two CCGT stations, with significant reductions in emissions.

A large range of information is available from the models used in the analysis of each scenario. CAENZ's own analysis focused on three principal areas:

- The impact of policy settings on the electricity supply system in terms of the type, capacity and cost of new generating capacity required, likely impact on the level and variation of electricity prices, carbon dioxide emissions and implications for system security.
- Demand for gas in each scenario, in terms of both the quantities of gas required and the requirements for gas as a stand-by fuel to support the intermittent nature of renewables generation.
- A review of the assumptions and costs used in the scenarios to ascertain whether the government's analysis represents a fair and complete comparison of the policy options available.

2.3 Review of the Gas Sector

The New Zealand Energy Strategy has pessimistic assumptions regarding the potential to generate new natural gas reserves in New Zealand to serve the country's primary energy needs, yet the strategy assumes thermal fuels such as gas will be available to provide back-up to renewable fuels. These assumptions have been made with little apparent analysis of the gas industry itself.

In this report, CAENZ examines the past performance of the gas exploration and production industry in generating new gas reserves and, importantly, identifies the conditions under which gas resources have successfully been brought onstream to meet market demand. This analysis is extended to the anticipated gas market under the 90 per cent renewables policy to ascertain the probable response of the gas industry to the resultant changes in gas market demand, both for electricity generation and for the wider energy markets.

The analysis is largely qualitative and involved consultation with a number of companies active in oil and gas exploration and development activities within New Zealand. In this context, the analysis reflects the core commercial imperatives which apply to investment in petroleum exploration and production which is characterised as capital intensive and high risk. Whilst the companies are experienced in the risk-taking implicit in exploration, market access and adequate and timely returns on the high development costs associated with bringing gas resources to market are primary considerations.

3 ELECTRICITY GENERATION

The immediate impact of the moratorium and 90% renewables target will be felt in the generation and transmission of electricity. CAENZ has assessed this impact by reviewing a series of case studies using the Electricity Commission's models of New Zealand's current and future electricity generation capacity under different policy scenarios. Use of the Electricity Commission's own scenarios rather than the development of a complete new set of scenarios was considered a more effective means of analysis as they provided a direct insight into the analysis behind government policy settings and are in some respects consistent, avoiding the need to repeat the studies needed to develop alternative versions.

From the large range of information provided by these models, CAENZ's own analysis focused on the following aspects of each scenario:

- The timing, type, capacity, cost and operating mode of new generating capacity additions.
- The likely impact on the level and volatility of electricity costs.
- Carbon dioxide emissions.
- Implications for system security in terms of back-up capacity required to support the intermittent nature of renewables generation.
- Demand for gas in terms of both the quantities of gas required and the requirements for gas as a stand-by fuel.
- A review of the assumptions and costs used in the scenarios to ascertain whether the government's analysis represents a fair and complete comparison of the policy options available.

3.1 Scenarios

Four scenarios have been analysed in this study and are described below. Three were developed by the Electricity Commission and published with their Grid Planning Assumptions:

- High Gas Availability
- Renewables Base Case (75% Renewables by 2025)
- 90% Renewables by 2025.

The fourth scenario was developed specifically for this study and was a variant of the Renewables Base Case with the early retirement of the coal-fired units at the Huntly power station. This represents a relatively minor change to the original scenario, but has a significant effect on gas demand for electricity generation and total carbon dioxide emissions.

Details of the pricing and cost assumptions used in each scenario are shown in Appendix 1.

High Gas Case

This case assumes no restriction of gas use through policy or carbon emissions. Gas prices and carbon charges are set sufficiently low at \$7/GJ and \$15/tonne respectively to make gas a preferred option for new generating capacity with several new CCGT stations brought online from 2011. Under these circumstances gas use for electricity generation is forecast to rise to about 120 PJ per annum in 2030, about double the current contribution. New indigenous gas reserves are assumed to be developed to match demand and the gas price is kept at a level to reflect domestic production. However, this scenario represents a potentially high carbon emissions case as a large amount of new coal capacity is permitted by the low \$15/tonne carbon charge. This carbon charge seems unrealistically low, resulting in a scenario that does not truly reflect the opportunities for gas in a carbon constrained future.

Renewables Base Case

This was initially the Electricity Commission's most likely scenario until the more extreme 90 percent renewables scenario was devised. It places a restriction of 75 PJ per annum maximum gas availability for electricity generation and raises the gas price from a current level of \$5.5/GJ to a ceiling of \$10/GJ in 2020, reflecting a move towards LNG price levels as new gas reserve generation does not match demand. Coal price at the Huntly power station is $4/GJ throughout. Carbon costs, which are additional to these prices, rise to $40 per tonne. Estimated gas consumption remains at more or less the same level as today, but falls to 45 PJ pa in 2020 as it becomes cost effective to burn coal at Huntly before rising to 70 PJ in 2030 when the Huntly station is assumed to be closed. Consequently carbon emissions are relatively high until 2030.

Huntly Early Retirement

This additional scenario is derived from the Electricity Commission's Renewables Base Case by retiring two units at the Huntly power station and relegating a further two to reserve status from 2017. The Otahuhu C and Rodney 1 CCGT plants are commissioned to replace the retired Huntly plant. Gas prices and carbon charges are assumed to be as in the Renewables Base Case. Under these circumstances, carbon emissions would be cut to about half those in the High Gas case and gas consumption sustained at 70 to 80 PJ per annum through to 2030. This case represents a sustained gas market with relatively low carbon emissions. However, it does imply a restraint on the use of coal for electricity generation.

90% Renewables Case

This case represents the intended government policy of 90% renewables use for electricity and also includes the government's planned moratorium on new thermal base-load stations. The imposition of the 90% renewables target by 2025 and the moratorium result in a greater investment in renewables generating capacity in the shorter term than would have been the case if the target had not been applied despite the higher capital cost of renewables plant.

Also, the 90% renewables target will make it more difficult for thermal plants to bid into the electricity market as the short-run marginal costs of renewables plant is very low. Consequently, gas use for electricity generation in this scenario is anticipated to fall to 40 PJ in 2023 compared to its present level of 60 PJ per annum. Two units at Huntly power station move to reserve status in 2013 and 2015, and the remaining two units are decommissioned in 2017, closing off a significant market for gas and coal.

Scenario Analysis Process

The Electricity Commission developed generation commissioning programmes for each scenario using their GEM model. This model minimises the total cost of generation system development over the period of the study, including capital, fixed operating and maintenance costs and fuel costs, subject to a number of constraints. A menu of generation plant options is input, along with fuel prices and details of constraints. The model then determines commissioning dates for plants to meet its cost minimisation objective. To ensure that adequate peak capacity is available, two additional constraints are included. These require installed capacity to exceed the peak demand in each year, allowing for some outages. The peak contribution of plant is derated using the following factors:

Thermal	0.95
Geothermal	1.0
Hydro with storage	1.0
Run of river hydro	0.65
Wind	0.15
Wave	0.15

These factors allow for the probability of plant of a particular type not being available at full installed capacity at the time of the peak load.

The capacity constraint is likely to have a major influence on model results, requiring the construction of open-cycle gas turbines and the use of demand side response mechanisms. Geothermal developments are advantaged by their high contribution to peaks, which seems reasonable in these circumstances.

GEM does not attempt to represent the details of system operation and, in particular, does not include the effects of hydro system inflow uncertainty. For this study, the scenarios developed by the Commission have been analysed in detail using the Stochastic Dual Dynamic Programming model (SDDP), which is a multi reservoir, stochastic hydro thermal scheduling model. A thirty-five year time horizon has been studied with monthly time steps. To represent load shape within each month, five load categories are considered, covering the variability of load within each month from peak through the shoulder periods and down to off-peak. The HVDC link is modelled, but not the AC transmission system, although the model has the capability to include AC system details. It is assumed that a 1400 MW HVDC upgrade occurs in 2012. See Appendix 3 for further details regarding the SDDP.

3.2 Generation Capacity Expansion

Total new capacity of each type of generation plant is shown in Figures 3.1-3.4 for the respective scenarios. Details of the size of individual power stations and their commissioning and decommissioning dates are tabulated in Appendix 4.

Figure 3.1 shows CCGT is not exclusively installed under the High Gas scenario. Only one new CCGT station, Otahuhu C, is included in the expansion plan before 2020. An additional two are built in the 2020-2030 period and a further two between 2030 and 2040, which are replacements for the modelled decommissionings of the existing Taranaki Combined Cycle and Otahuhu B stations. Thus, by 2030, annual average gas consumption rises to over 120 PJ.

By 2035, geothermal is the dominant renewables technology with around 755 MW of new (baseload) capacity. Hydro makes a significant contribution with 733 MW, while wind contributes 409 MW.

With gas constrained to a maximum of 75 PJ pa in the Renewables Base Case, expansion plans are dominated by renewables. By 2035 new capacity from geothermal, hydro and wind are 1285 MW, 1158 MW and 2219 MW respectively. New gas fired capacity is only introduced after 2030 in anticipation of the retirement of existing CCGT plants as they reach the end of their economic life.

The Coal Retirement Scenario differs from the Renewables Base Case with the installation of two CCGTs to replace the coal-fired Huntly capacity, which is either decommissioned or relegated to reserve status.

The 90% Renewables scenario is a more emphatic version of the Renewables Base Case. Wind capacity dominates if there is an extensive call on renewables capacity since the amount of cheaper geothermal and hydro capacity is more limited. New gas-fired plant does not appear until late in the cycle, when existing plant is replaced. Also, at the end of the scenario outlook, coal-fired carbon capture and storage technology is introduced to

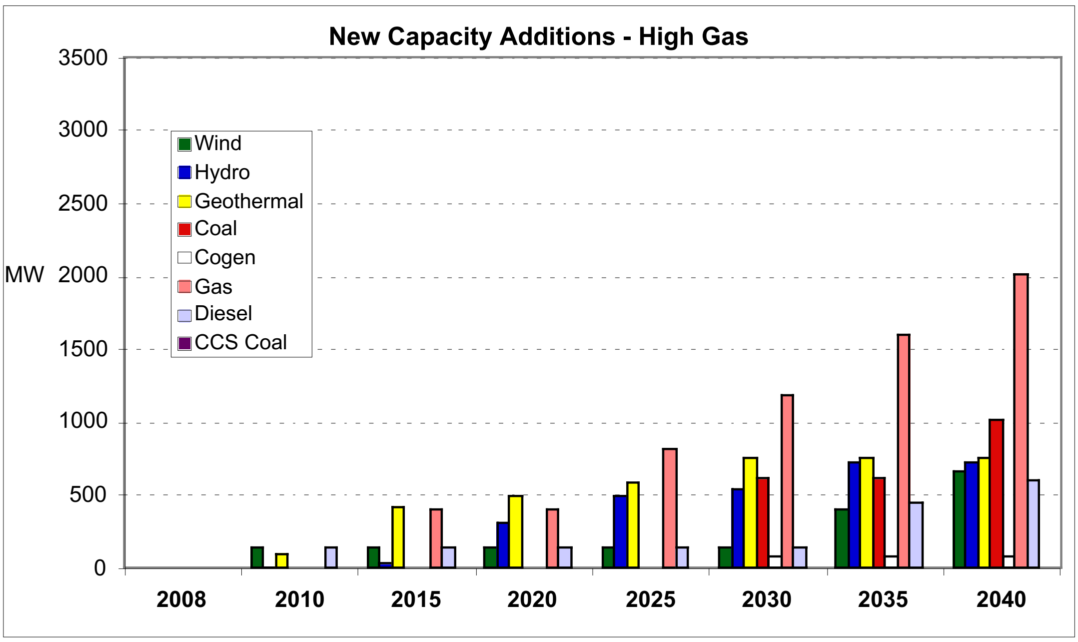

Figure 3.1: Cumulative New Installed Capacity – High Gas Scenario

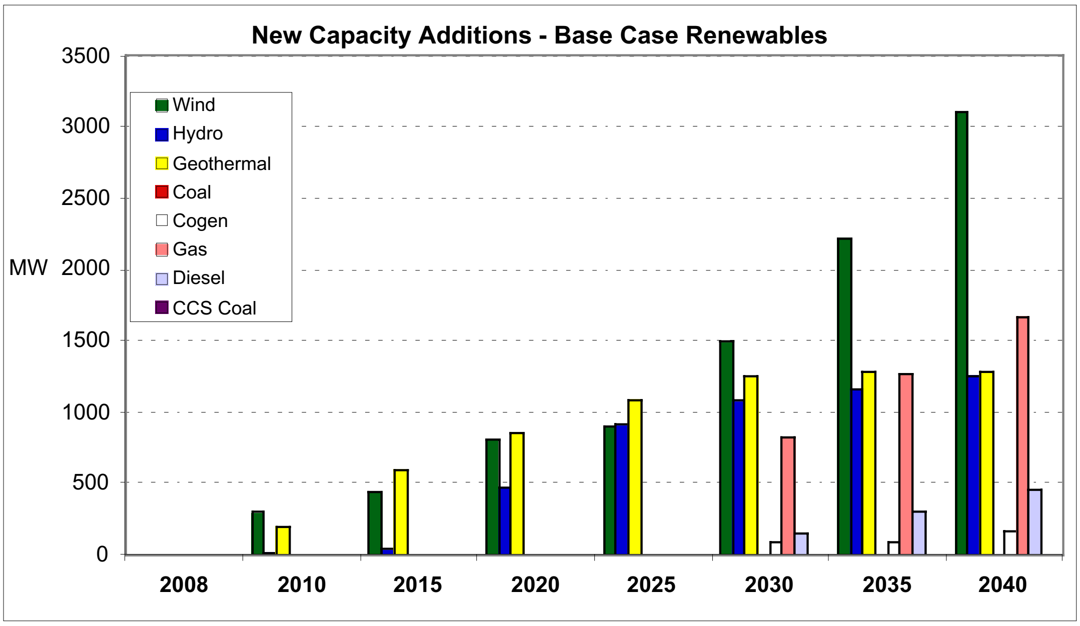

Figure 3.2: Cumulative Installed Capacity Additions – Renewables Base Case Scenario

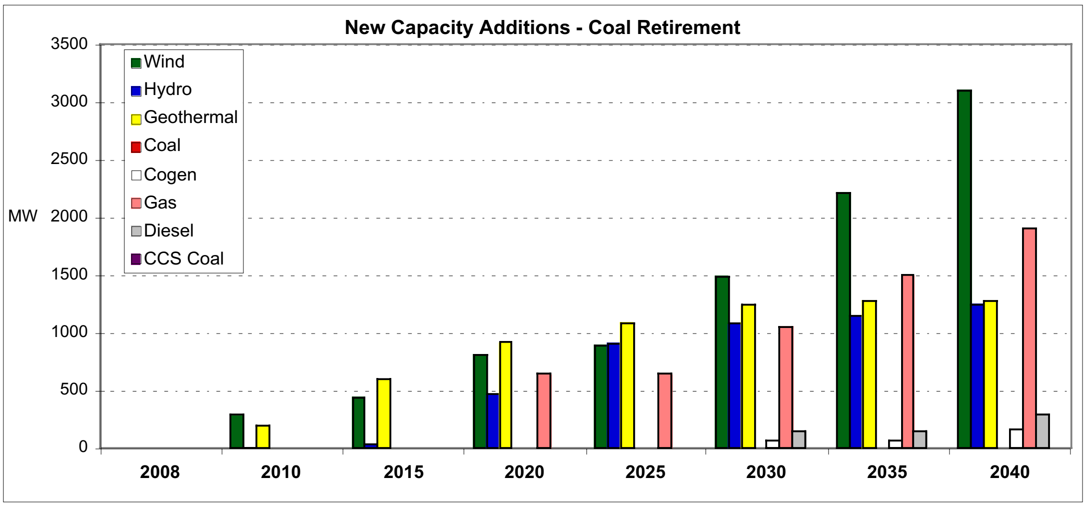

Figure 3.3: Cumulative Installed Capacity Additions – Coal Retirement Scenario

maintain low levels of carbon dioxide emissions.

3.3 Plant Costs

Capital Costs

The total cumulative capacity additions and the associated capital costs are summarised in Table 3.1 with the scheduling of capital expenditure illustrated in Figure 3.5.

The 90% Renewables case involves installing more capacity than the Renewables Base Case because wind generation achieves a lower capacity factor than most other plant types. Thus for a given energy requirement (MWh), more capacity (MW) needs to be installed. The higher MW requirement under the 90% renewables case results in a capital cost of some $2b (11.7%) more by 2035.

The High Gas scenario stands in stark contrast to the other scenarios, requiring around half as much capital expenditure. However the total discounted cost streams narrow as CCGT plant must pay for gas in order to generate whereas wind plant has lower operating costs.

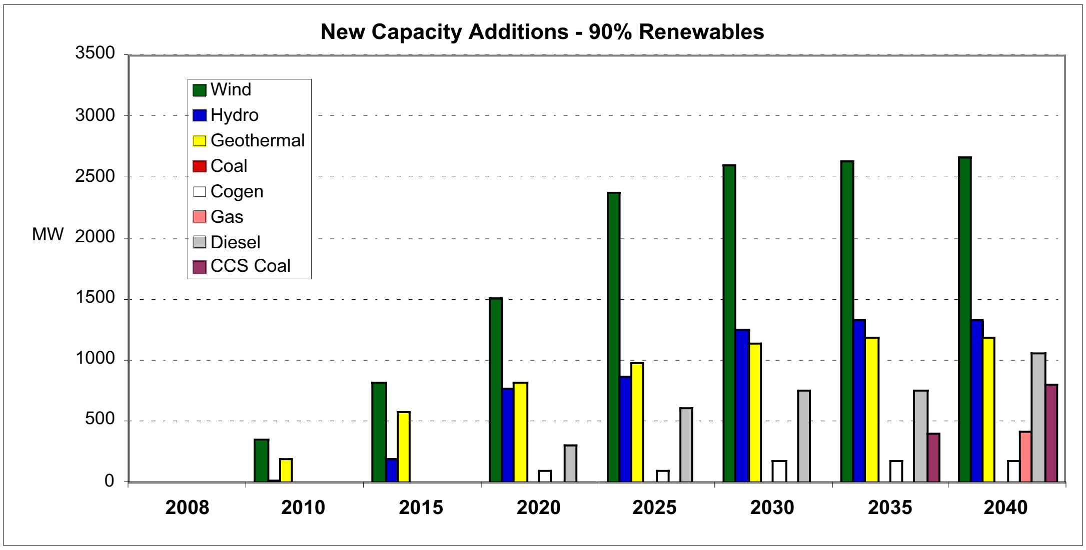

Figure 3.4: Installed Capacity Changes – 90% Renewables Scenario

Cumulative Capital Expenditure ($m)				
	High Gas	Base Scenario	Coal Retirement	90% Scenario
2015	2,230	3,433	3,433	4,907
2020	3,570	7,028	8,145	10,449
2025	5,858	9,964	10,662	14,163
2030	7,862	14,312	14,579	17,355
2035	9,947	17,513	17,658	19,570
Total New Plant Installed (MW)				
	4654	6302	6239	6639

Table 3.1: Cumulative Capital Expenditure and Capacity Additions (source: Electricity Commission GEM data base)

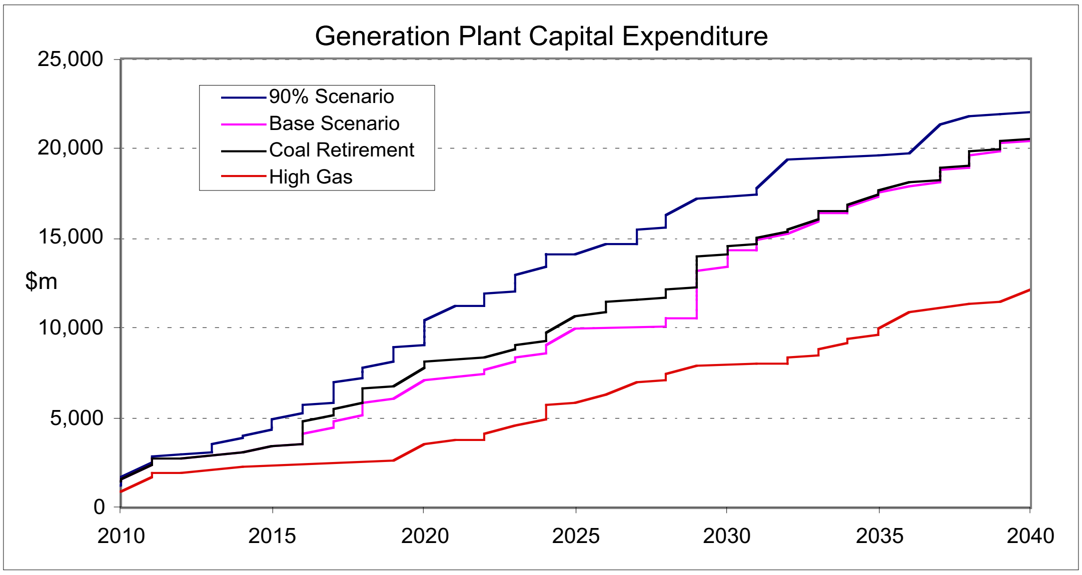

Figure 3.5: Generation plant capital expenditure

Long Run Marginal Costs

Long run marginal costs (LRMC) are useful in understanding the capacity expansion path for the least-cost plant build determined in the models. These are levelised unit costs which include capital, operating and maintenance and fuel costs over the expected lifetime of the plant. Normally, the lowest cost plant will be built first although plant with an apparently higher cost can also be installed as required for stand-by or peaking service.

A selection of LRMCs for specific plant are shown in Tables 3.2 and 3.3. These give some guidance as to what order new plant have been installed in, particularly for the latter three scenarios.

Short Run Marginal Costs

Short-run marginal cost (SRMC) is the price at which generators would bid into a perfectly efficient market. In New Zealand, SRMC usually represents the lowest price at which plant will be offered. SRMC covers variable costs but not fixed costs such as capital costs. The highest offer price accepted sets the market clearing price for that period. SRMCs for the four scenarios are shown in Figures 3.6-3.9.

Lowest SRMCs occur for the High Gas scenario, due in part to the assumption a low carbon emission cost for this scenario. Also, the gas price is held at $7/GJ, in contrast to the other scenarios where this price is projected to be surpassed by 2014. Carbon price is therefore

Long Run Marginal Cost of Thermal Plant, Including Carbon Costs, For Other Scenarios (Excluding High Gas)										
Name	MW	Capital $/kW	Life Years	O&M $/kW	Fuel Delivery $/GJ	VOM $/MWh	Plant Factor %	Total Cost ($/MWh) For various commissioning years:		
								2010	2015	2020
Tauranga Coal	300	2400	25	40	0	9	80	113.8	121.5	123.3
Lignite Southland	400	2460	25	44	0	9.9	80	99.0	107.6	109.6
Otahuhu C	407	1035	25	50	0.75	4.25	80	94.1	100.9	104.7
Rodney 1	240	1150	25	50	1.5	4.25	70	105.7	112.7	116.6
OCGT	150	800	25	100	0	4.26	5	475.6	481.7	483.2
Geothermal 1	80	4000	30	84	0	0	90	58.3	59.0	59.1
Geothermal 10	80	6250	30	84	0	0	90	83.6	84.3	84.5
Generic Wind	100	2600	20	-	0	16	40	81.7	81.7	81.7

Table 3.2: Long Run Marginal Costs of New Non-Hydro Plant (excluding for High Gas Scenario)

Long Run Marginal Costs for Hydro Plant						
				EC Total		PB Data
	MW	Capital $/kW	GWh per year	Excl O&M $/MWh	Incl O&M $/MWh	excluding O&M $/MWh
Luggate	90	4500	394.2	86.16	91.41	110
Queensberry	180	4500	788.4	86.16	91.41	91
Dobson	50	3600	219	68.93	73.04	126
North Bank tunnel	280	3571	1226.4	68.37	72.48	135
Wairau	70	3143	306.6	60.18	63.83	99
Mohikinui	70	4286	306.6	82.06	86.85	188
Tuapeka	340	4000	1489.2	76.58	81.15	64

Table 3.3: Long Run Marginal Costs of New Hydro Plant

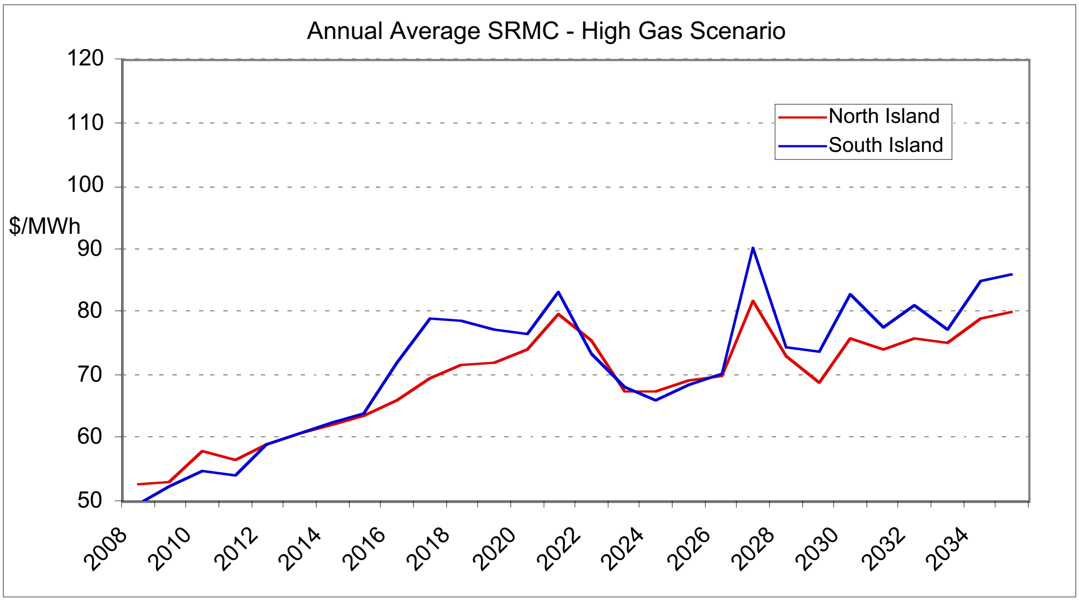

Figure 3.6: Annual Average SRMC – High Gas Scenario

the main variable in total gas price, determining its competitive position vis-a-vis renewables technologies. As a result, future costs are higher than those applying at present but they only occasionally rise above $80/MWh.

The SRMCs for the two Electricity Commission renewables scenarios, Renewables Base Case and 90% Renewables, are at similar levels although more volatile in the 90% renewables case, as shown in Figures 3.7 and 3.9. The levels are similar because CCGT generation is the often the marginal generator in both cases. The 90% Renewables scenario exhibits greater volatility as it includes more intermittent generation sources such as wind and to a lesser extent hydro. The other notable feature is that, in both scenarios, the SRMC is modeled to rise from the current $50-60/MWh to over $90/MWh within a decade as carbon costs and fuel prices rise.

It should be noted that since almost all renewables are "use it or lose it" and have no fuel costs, they are likely to bid into the

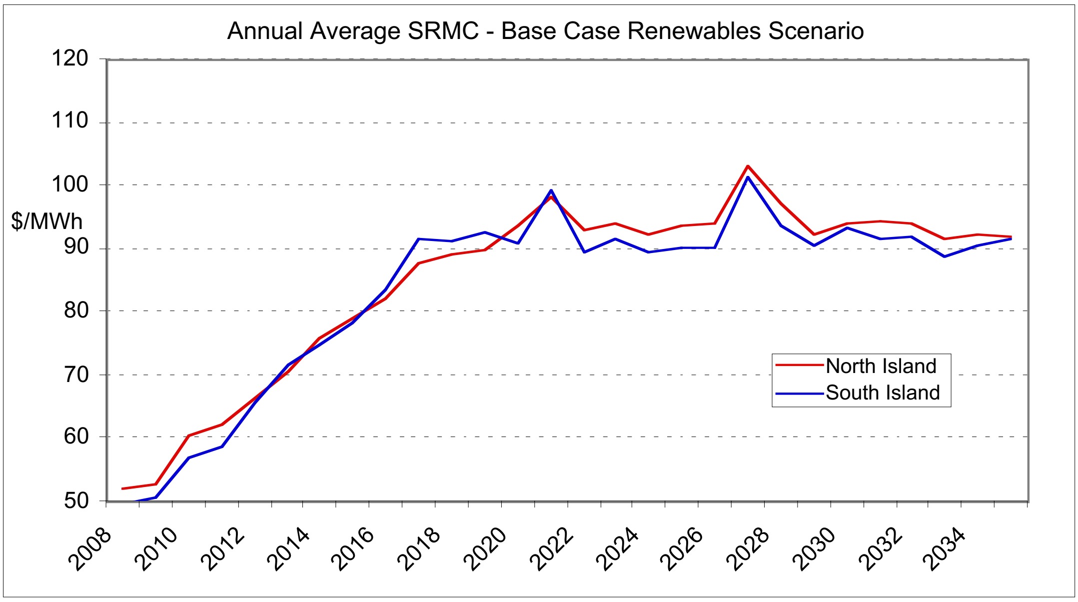

Figure 3.7: Annual Average SRMC – Base Case Scenario

market at zero or near zero price. As these plants will rarely be marginal, some higher cost plant will set the market clearing price, enabling the renewables plants to cover fixed costs.

Volatility of Short Run Marginal Costs

The volatility of electricity prices, as represented by SRMC, will be higher in situations with a greater preponderance of plant with intermittent generating characteristics, such as wind generation. This is illustrated in Figures 3.10 to 3.13 which show the probability that a certain price is exceeded for the various scenarios.[1]

If domestic natural gas is available, and consequently gas prices remain relatively low as in the High Gas scenario, electricity generation costs will remain low, below \$80/MWh.

[1] An example of the interpretation of these cumulative probability distributions is as follows. Referring to Figure 3.10, for 2035, there is an extremely small probability that price will exceed \$300/MWh, and a 100% probability of price exceeding zero. These two examples define the end points, or extremities of the chart. As an example of an intermediate value, there is a 10% probability that price will exceed \$110 per MWh, in 2035. These distributions have been generated by considering prices in each of the five load categories for each month of the year, and for all 74 inflow sequences simulated.

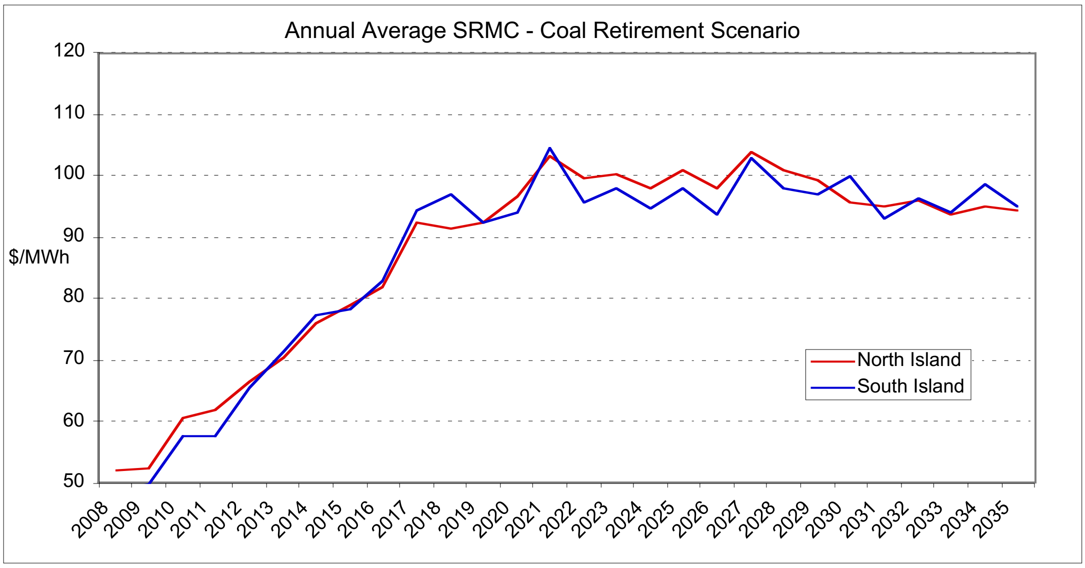

Figure 3.8: Annual Average SRMC – Coal Retirement Scenario

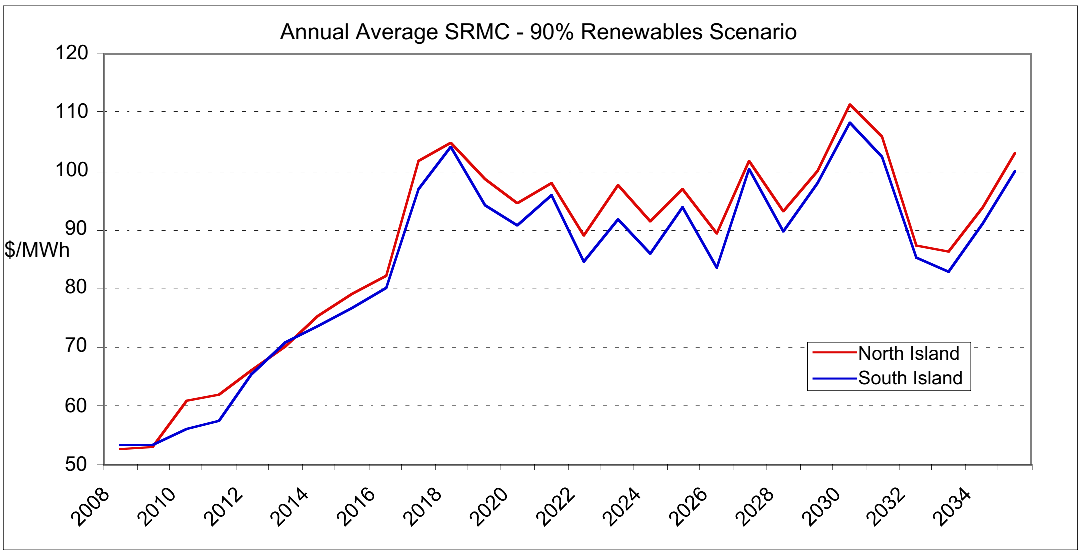

Figure 3.9: Annual Average SRMC – 90% Renewables Scenario

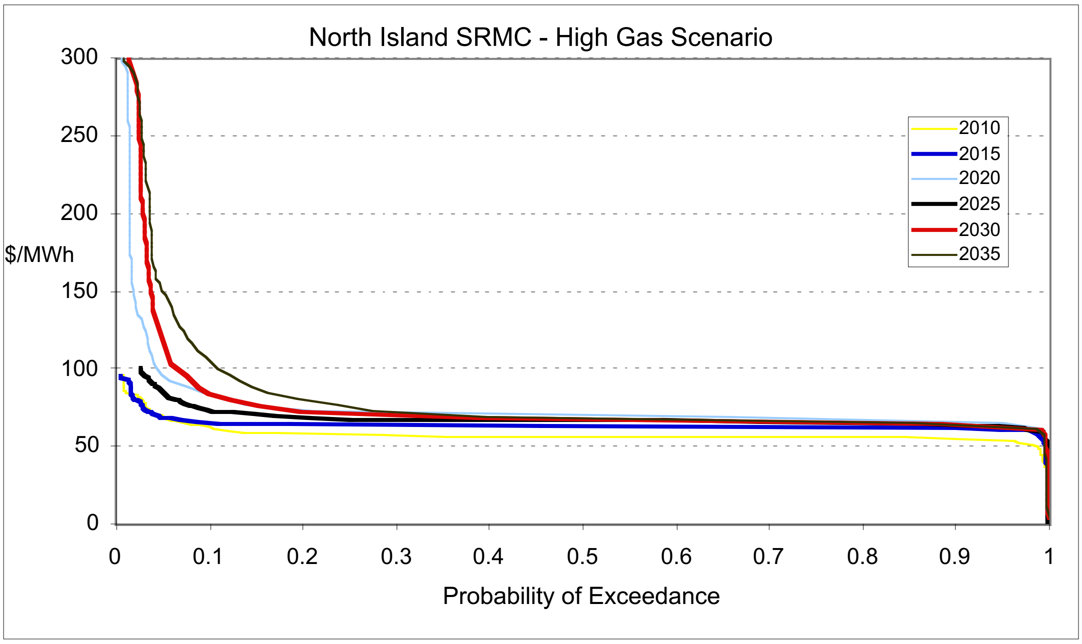

Figure 3.10: North Island SRMC Probability of Exceedance – High Gas Scenario

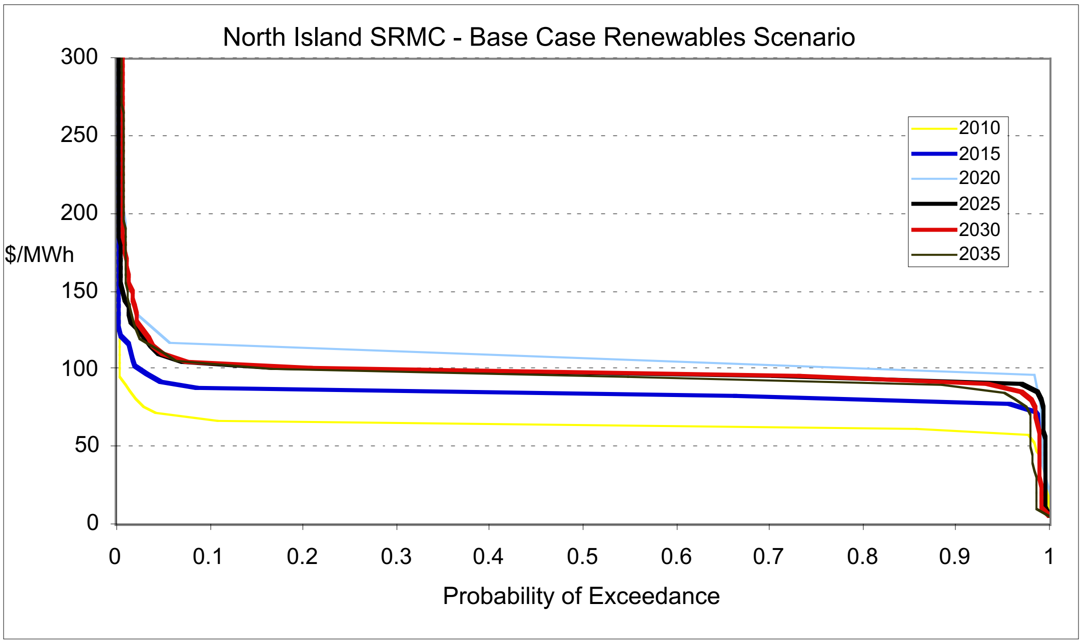

Figure 3.11: North Is SRMC Probability of Exceedance – Base Case Scenario

During any year, costs, as might be determined by seasonality or intermittent shortages, rise above $100/MWh, less than 10% of the time, and for very much less than 10% of the time prior to 2020.

Figure 3.13 clearly illustrates the impact of increased renewables capacity on electricity cost volatility. Whilst the average SRMCs for the Base Case Scenario and the 90% Renewables Scenario are quite similar, the 90% Renewables case exhibits the higher level of volatility in cost, with the probability of SRMC exceeding $200/MWh being 5% to 20% in most years. In contrast, under the Renewables Base case, the probability that the cost is over $200/MWh at any time during any year is virtually negligible.

To further illustrate the impact of renewables

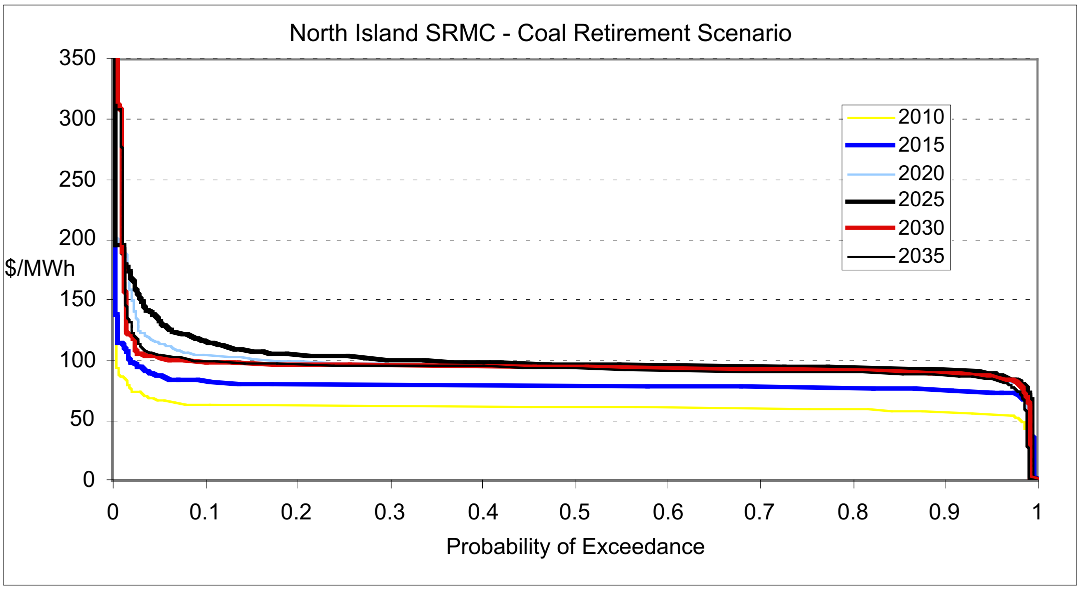

Figure 3.12: North Is SRMC Probability of Exceedance – Huntly Retirement Scenario

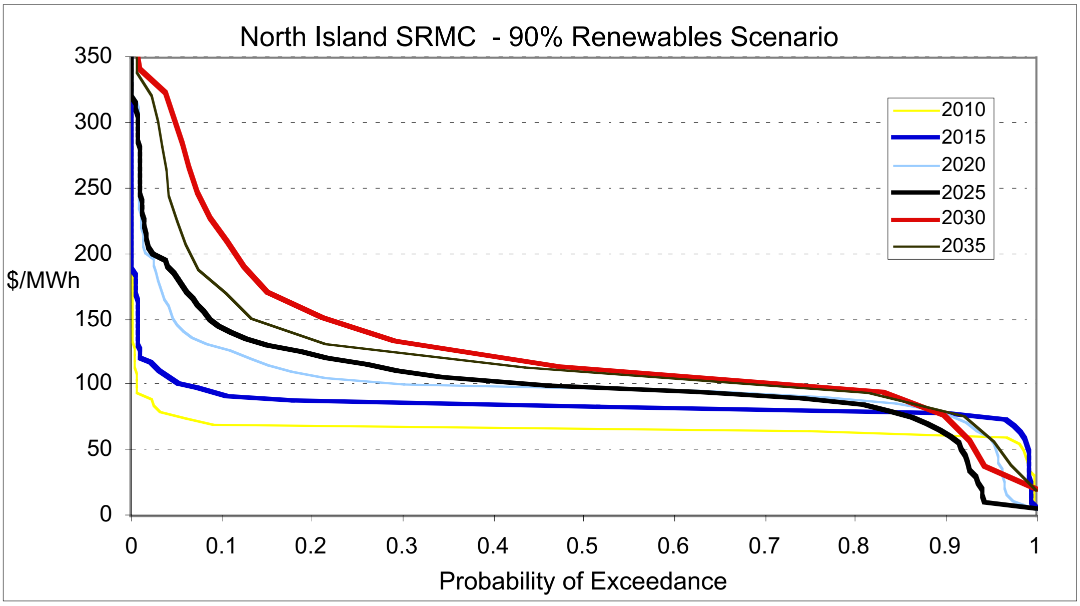

Figure 3.13: North Is SRMC Probability of Exceedance – 90% Renewables Scenario

on electricity price volatility, Figure 3.14 compares the SRMC determined for the peak period of each month in 2025. It can be seen that in a dry year, costs spike higher and for longer in the 90% Renewables scenario than the Renewables Base Case.

3.4 Effects of Intermittent Generation

Hydro, geothermal and wind generation all affect overall power system performance in quite different ways, and in particular have significantly different influences with respect to generation reserves. Several different types of reserves are required for secure system operation:

- Dry year reserves are needed to provide additional energy over a period of a few weeks when hydro storage is low. These plants need not be fast starting. As hydro storage takes some time to run down, plenty of time is available for these generators to be brought into service, so

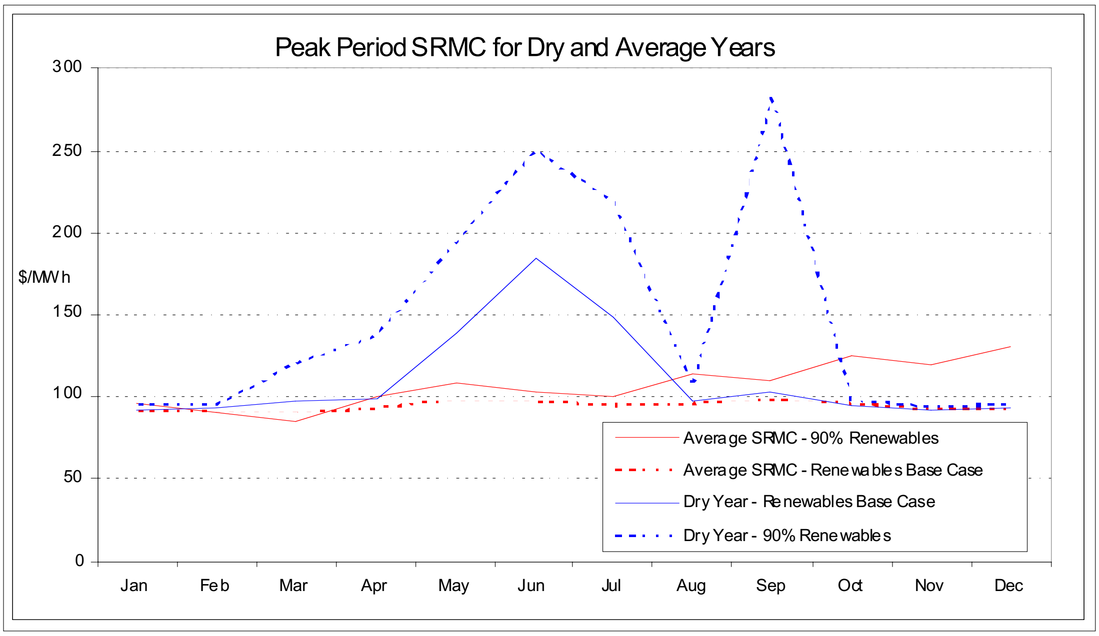

Figure 3.14: Comparison of North Island SRMC for Average and dry years, for renewables scenarios for 2025

this function could be filled by older thermal plants. The Marsden A oil fired plant, for example, was used in this role.

- Spinning reserve is provided by plant which is connected to the system and is partly loaded. These units respond automatically to the drop in frequency that occurs when some other generation source, or the HVDC link, trips off. Sufficient capacity is provided as spinning reserve to ensure system security in the event of the largest unit currently in service tripping off.
- Frequency keeping reserve compensates for the constant small load variations. As loads switch on and off, the total generation required changes by the same amount. Load changes would result in a frequency change, if all generation sources were to remain constant. The frequency keeping station adjusts its output to compensate, thereby keeping the frequency at 50 Hz.
- An additional category of reserve will be required when large amounts of wind generation are connected to the system. This might be referred to as “replacement reserve” and would be called upon when wind generation output is forecast to drop within the next hour or two.

Because of their technical characteristics, different types of generating plant are more suited to providing the various types of reserve required:

- Hydro plant is extremely flexible, and so is ideally suited to frequency keeping where constant changes in output are required. It is also ideal for providing spinning reserve. Even during dry periods, hydro plant can usually be used to meet short term system peaks or contingencies.
- Geothermal plant is not suitable for providing spinning reserve, but operates as reliable base load generation – it is not subject to weather effects, and so does not suffer from the variability of hydro plant, but then it is unable to contribute to meeting system contingencies.
- Wind generation varies uncontrollably over short periods of time, and is not able assist in meeting system contingencies. Figure 3.15 illustrates the variability of a typical wind plant, varying from zero to maximum over a 24 hour period.

Some variability in wind can be forecast, as shown in Figure 3.16. The component of variability that can not be forecast must be able to be covered by fast-acting reserves. Plant which is not in service can not be used to provide spinning reserves – hence an open cycle gas turbine cannot provide reserve unless it is running at part load, which is a very inefficient condition. The burden of providing

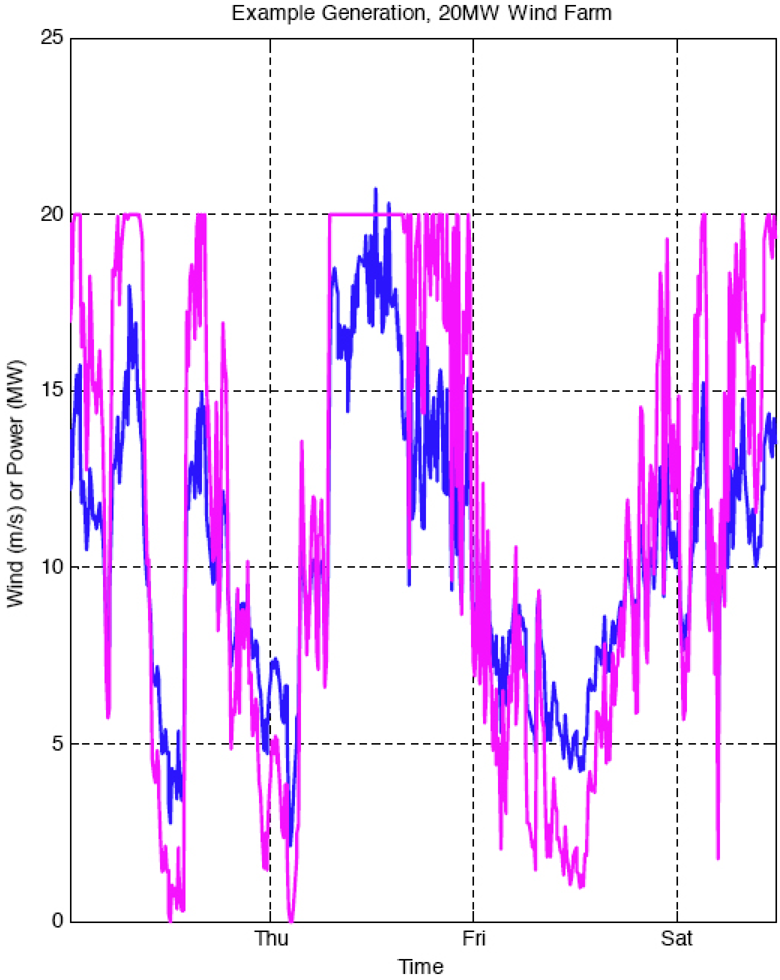

Figure 3.15: Typical wind plant variability (Electricity Commission)

reserves is likely to fall largely on hydro plant and, by means of interruptible loads, on electricity users. Additional reserves are likely to be needed when total wind generation capacity exceeds 1000 MW [2]. Currently 321 MW of wind capacity is installed, which will rise to 485 MW when plants under construction are completed[3].

Slower start reserves will also be required to back up wind generation. These reserves could be provided by open cycle gas turbines which can be brought into service in less than half an hour. These plants could cover for situations where low wind output is forecast.

Reserve capacity and energy reserves can be costly, and this cost should be allocated to wind generation projects, when these demand additional supplies of reserves. Currently with the inter-island HVDC link limited to one pole, additional reserves are required for this to operate at full load. The cost of these reserves is proving to be a constraint, which should be a warning regarding the effects of larger amounts of wind generation requiring additional reserves. Reserve requirements are further complicated by the need to consider correlations in the outputs of different wind farms, especially with developments clustered in high wind regions.

The issues regarding predictable and random variations in wind generation are likely to become very significant issues for the New Zealand power system, but have not yet been investigated in detail. The GEM scenario development model used by the electricity Commission does not make the correct economic trade-offs between the requirements of the various types of generation for reserves, and their abilities to contribute to reserves.

[2] Bruce Smith, Electricity Commission, 17 December 2007, Transmission to Enable Renewables Workshop.

[3] Wind Energy Association.

3.5 Transmission Requirements

The Electricity Commission's scenario development model does not represent AC transmission system constraints. Hence the scenarios used in policy making could not take into account transmission system costs. This would not be of such significance if all types of generation had similar characteristics. However many renewable sources are located further from load centres than thermal plants might be, and so must result in a greater need for transmission system developments.

If the full benefit of renewable generation is to be achieved, the transmission system must be capable of transporting this energy at all times. Hydro generation can be controlled, so its output can be scheduled to manage transmission constraints. For wind or wave generation, transmission must be sized to cope with full output of all plants at any time. The intermittent nature of some renewables will result in lower utilisation of the required transmission services, effectively increasing costs per kilowatt-hour of generation.

In its submission on the New Zealand Energy Strategy, Contact Energy has expressed concerns regarding transmission capacity out of the Otago region. These concerns will be heightened by the Hayes and Lake Mahinerangi wind generation projects, which may therefore not be able to deliver their planned outputs without transmission upgrades.

Figure 3.17 was published by Transpower in mid 2007 showing existing and potential projects for which information is in the public domain. Possible transmission line enhancements required for the 90% renewables scenario include the following.

Duplexing the conductors on following existing lines:

Roxbugh - Livingstone	$60.3 m
Waitaki – Livingstone	$18.7 m
Bunnythorpe – Haywards	$63.6 m
Bunnythorpe – Tokaanu	$115.2
Tokaanu – Whakamaru	$48 m

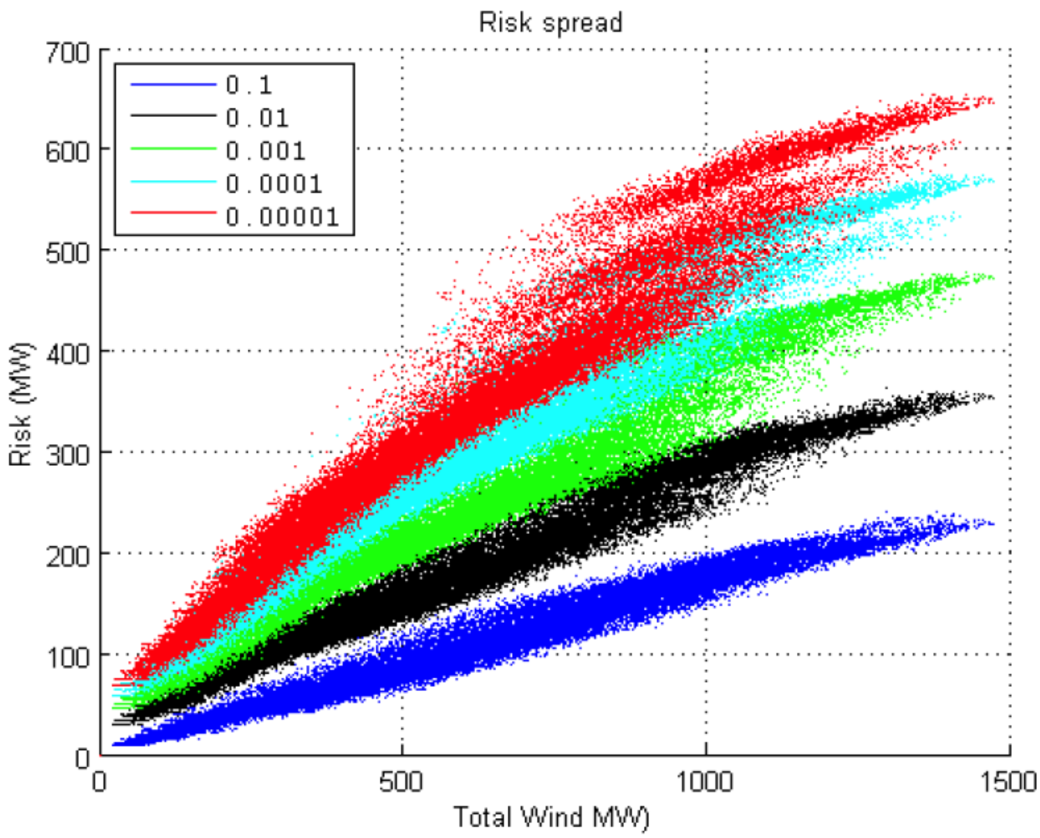

Figure 3.16: Two Hours Ahead Pre-dispatch Confidence Levels for Wind Output (Electricity Commission)

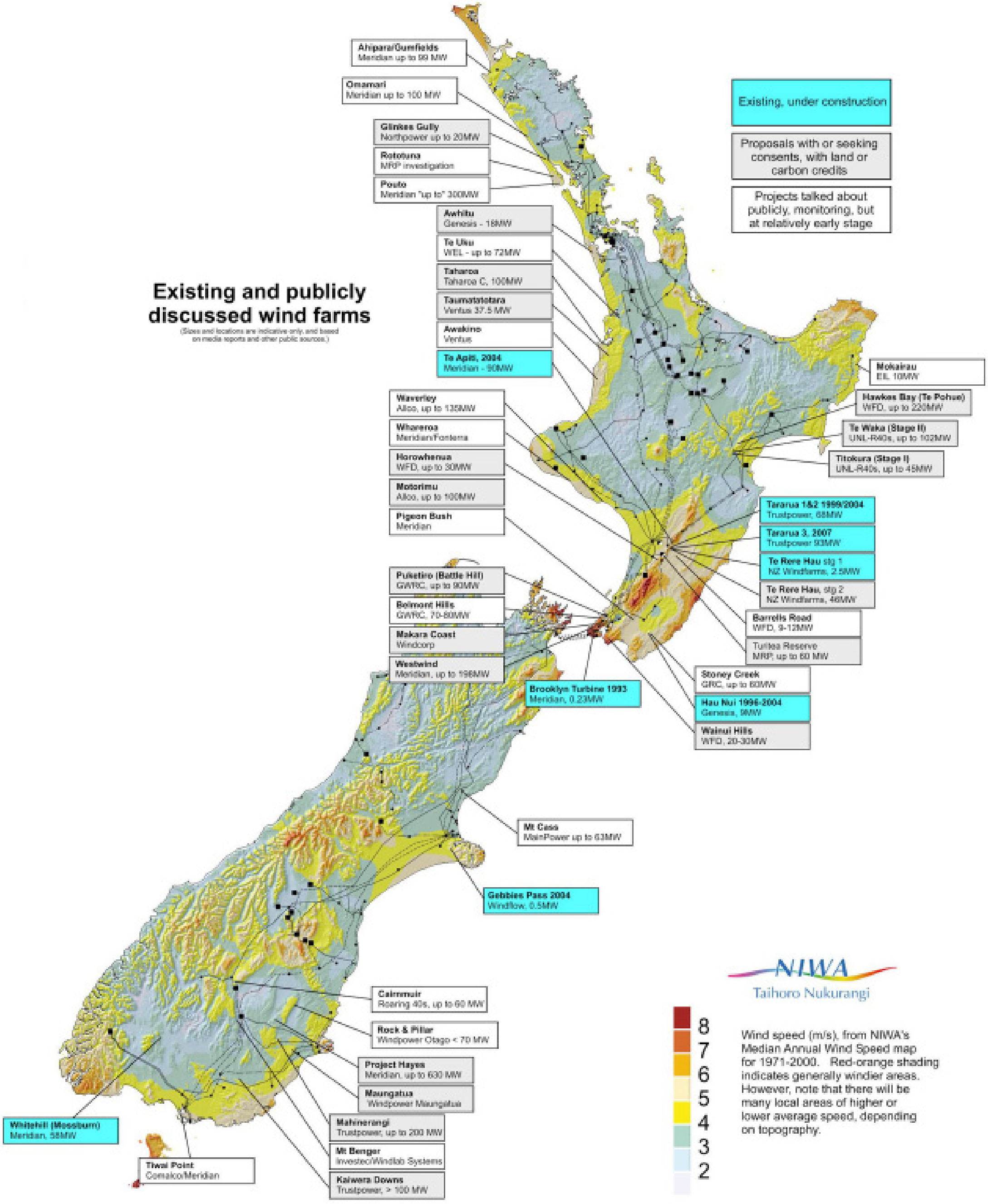

Figure 3.17: Likely Locations for Wind Generation

New lines, excluding substation costs:

Roxburgh – Clyde	$50 m
Clyde – Twizel	$205 m
Bunnythorpe – Woodville	$36.5 m

The above transmission cost data has been obtained from Transpower's proposals for the Whakamaru to Auckland line and for the HVDC upgrade project. The average per kilometre cost given for the construction of a Whakamaru to Auckland 220 kV line has been used for new line costs.

No comprehensive analysis of transmission requirements for intermittent renewables has been published. Neither have details of the tools required for this type of analysis been published – it appears that this is still an area in the early stages of analysis. Clearly, the tradeoffs between remote, intermittent generation sources and other controllable, more reliable, sources has been carried out without quantitative analysis which takes into account the cost of transmission developments.

Thus, to the extent that transmission requirements have not been costed in this study, the costs of renewables used in this study represent a lower bound. Unlike augmentations to the core grid, the costs of which are logically shared by all users, new transmission infrastructure to facilitate some wind farms and other renewables such as remote hydro should be charged against this new generation[4]. Such costs have not been included in this study, or those carried out by the Electricity Commission. Thus renewables generation costs are optimistic compared to the thermal generation costs presented here.

3.6 Gas Consumption

Gas consumption for the various scenarios is shown in Figure 3.18.

Projections under the different scenarios show that demand for gas is sensitive to the policy environment and the cost competitiveness of gas-fired generation, in particular with coal:

- ***High Gas scenario:*** Gas consumption for electricity generation increases incrementally as additional CCGT stations are built, rising to over 80 PJ pa when Rodney is assumed to be commissioned, to over 100 PJ pa when Otahuhu C is built and over 120 PJ pa after 2030 with the addition of a further CCGT plant.
- ***Renewables Base Case:*** Without incremental CCGT capacity being constructed, gas consumption is projected to continue at the current level of about 60 PJ pa. A significant drop occurs in 2020 as gas-fired generation, at a gas price of $9-10/GJ, is not competitive with coal costing $4/GJ at the Huntly power station, even with the $40/ tonne carbon impost applying at the time. In reality, gas may be able to bid in successfully at less than $9/GJ, in which case gas consumption for electricity generation would continue at around 60-70PJ pa. This level of gas consumption is projected to occur after 2030 in any case after the closure of the Huntly station.
- ***Coal Retirement Scenario:*** Gas consumption for electricity generation remains within the range of 60 to 80 PJ pa with the retirement of two of the turbines at Huntly which are assumed to be retired in 2017 and replaced by two CCGT plants. The case for Huntly's retirement is reasonable if the capacity is replaced with other non-intermittent capacity such as CCGT and results in lower carbon emissions. Retention of the Huntly turbines for back-up, and likely significant use during calm and/or dry periods, seems necessary in high renewables settings.
- ***90% Renewables Scenario:*** Gas consump-

[4] This may be conceptually similar to the way in which the HVDC link is currently charged even if there is an arguable case that non-direct users do benefit from it.

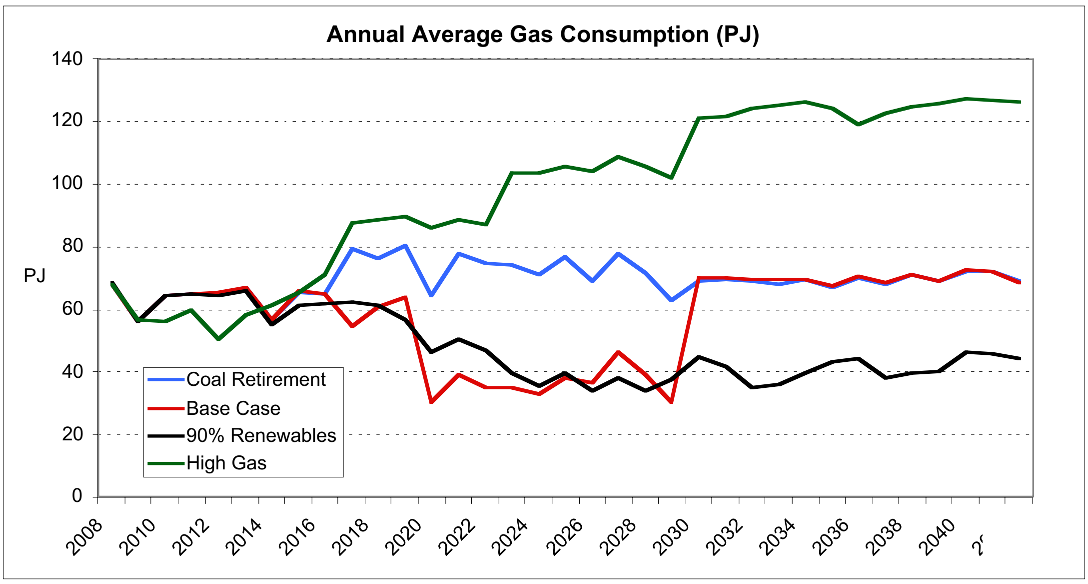

Figure 3.18: Gas Consumption – All Scenarios

tion in this case falls gradually from the current 60-65 PJ pa to around 40 PJ pa by 2022, which is consistent with the higher target for renewables generation. When the 90% renewables target is achieved, the share of thermal generation is about 5,500 GWh pa as compared to some 13,500 GWh currently[5] and is less than the output of two of the current three CCGT stations generating at 85% load. Thus stranding or under-utilisation of assets could occur if the renewables target is mandated or is achieved before the target year of 2025.

3.7 Renewables Share of Generation

Figure 3.19 shows the share of generation from renewables under the four scenarios.

Average annual generation from renewable resources under the Renewables Base Case scenario rises to over 80% renewables at the end of our period of principal interest (2030) and is very similar to that of the Coal Retirement scenario.

The 90% Renewables case does not achieve its target until 2024 and paradoxically falls to a lower level than the Renewables Base Case towards the end of the analysis period due to the reliance on technologies such as thermal generation carbon capture and storage to maintain carbon emissions at low levels.

The High Gas scenario sees the share of renewables fall below 65% by around 2030, slightly lower than current levels.

3.8 Carbon Dioxide Emissions

Carbon dioxide emissions from electricity generation under the various scenarios are shown in Figures 3.20-3.23.

The High Gas scenario has steadily rising carbon emissions from electricity generation. This is due to both increased use of gas and the assumed continued use of coal at Huntly and new coal fired plants. The high thermal usage is supported by the low carbon price of $15 per tonne assumed for this scenario, which compares with $40/tonne in the other scenarios and is generally lower than most forecasts. The Electricity Commission did not analyse a scenario with gas meeting the thermal fuel needs without being complemented by coal.

Carbon emissions in the Renewables Base Case shown in Figure 3.21 illustrate the effect of fuel prices and carbon charges in the interplay between gas and coal. In this scenario coal price is held constant at $4/GJ but the gas price is escalated, reaching $9/GJ in 2019. At this time, coal becomes cheaper for electricity generation, notwithstanding a $40/tonne

[5] Gas + coal generation was 13681 GWh in 2006 according to Energy Data File, June 2007.

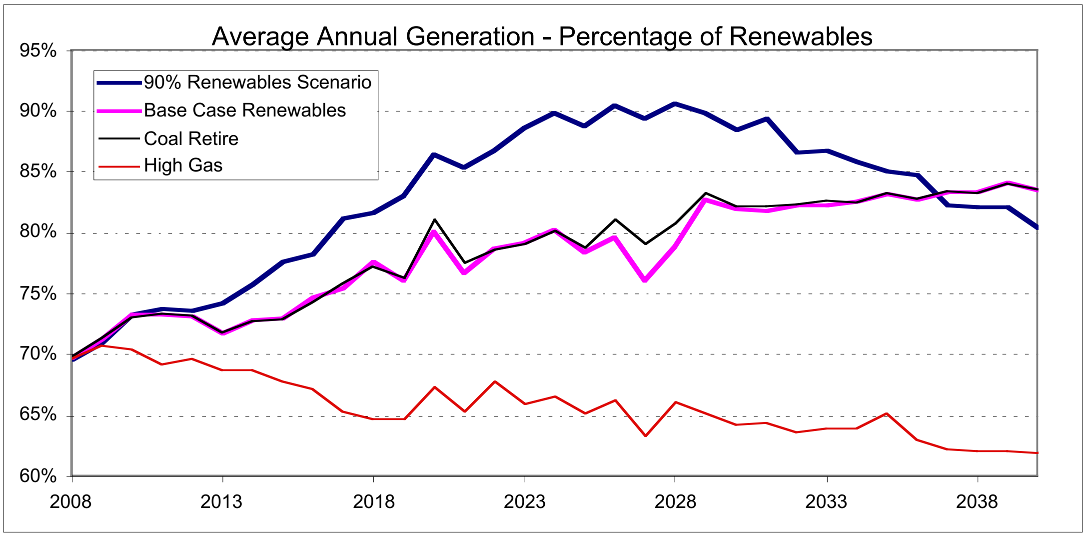

Figure 3.19: Percentage of Renewables

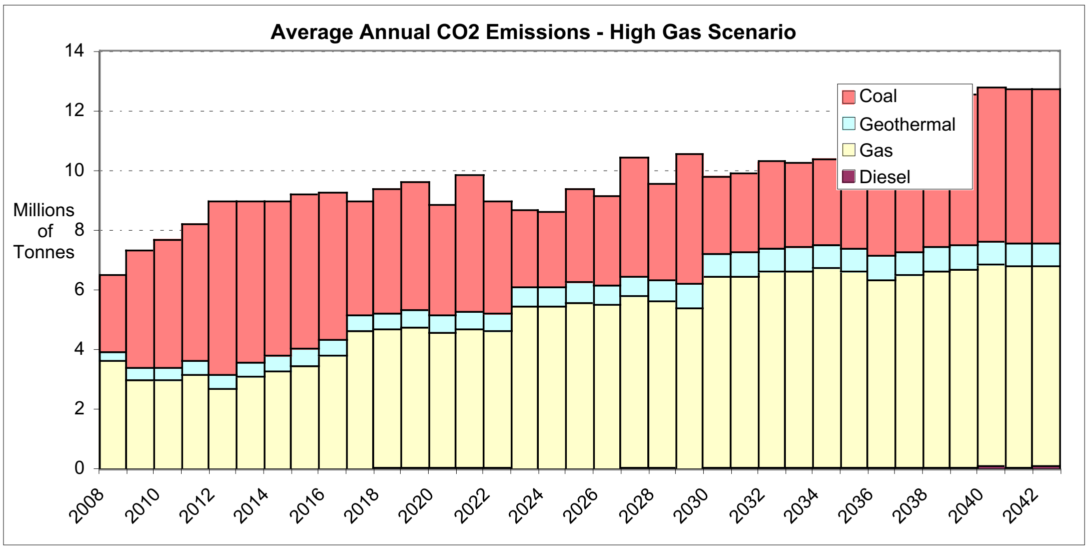

Figure 3.20: Carbon Emissions – High Gas Scenario

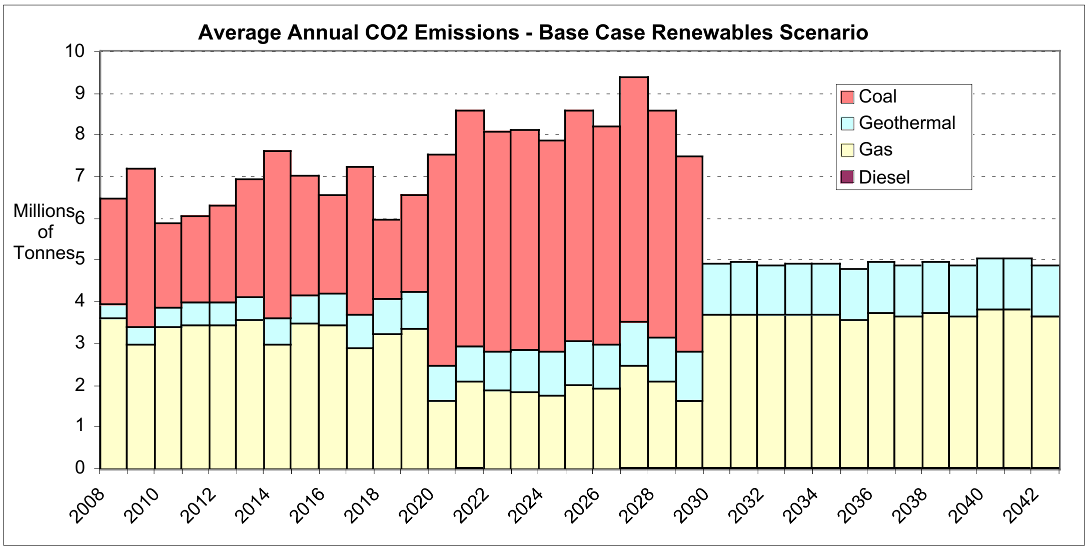

Figure 3.21: Carbon Emissions – Base Case Scenario

carbon charge, and carbon emissions rise to a high level for a period of eight years when the Huntly power station is assumed to close. With otherwise idle CCGT capacity available, gas will likely in practice bid in at somewhat below $9/GJ, resulting in higher gas use, lower coal use and lower carbon emissions. Equally, if whatever gas is available and deliverable and is successfully traded to a higher value use, for example, methanol manufacture, then coal burn makes sense.

In general, a higher carbon price penalises coal more than it does gas. A carbon charge slightly higher than $40/t would have a similar effect to a lower gas price and switch generation to CCGTs rather than Huntly on coal. Conversely, a lower carbon charge advantages coal more than it does gas. This unintended consequence does suggest that the maintenance of a stable and viable gas market, likely driven by CCGT generation, will be beneficial to the country.

The 90% renewables case shown in Figure 3.23 will result in sustained reductions in carbon emissions from the electricity sector due to the enhanced use of renewables and less use of thermal fuels. In the later stages of the study period, use is made of carbon capture associated with coal-fired generation plant, a potentially expensive and largely unproven technology.

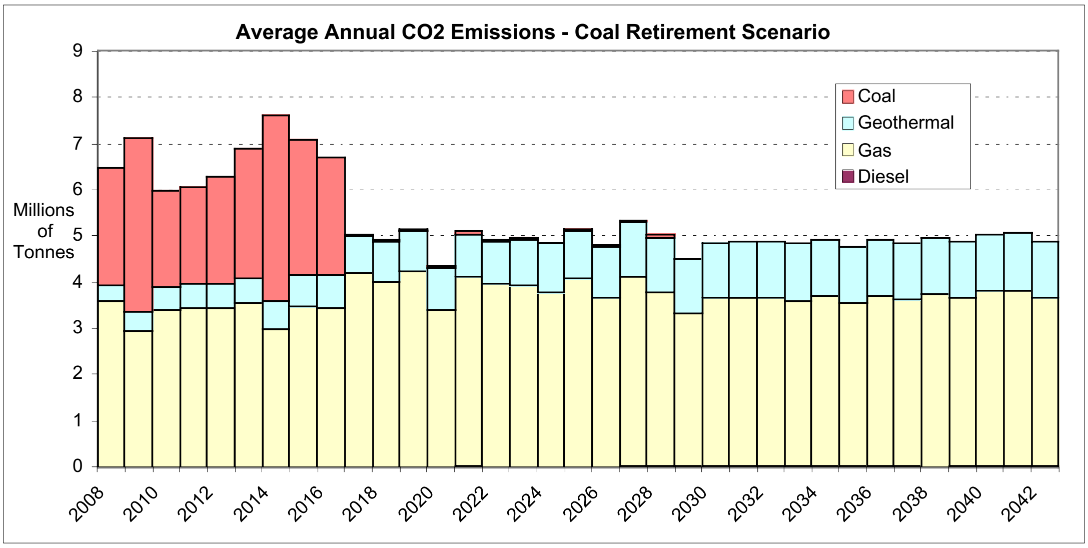

Figure 3.22: Carbon Emissions – Coal Retirement Scenario

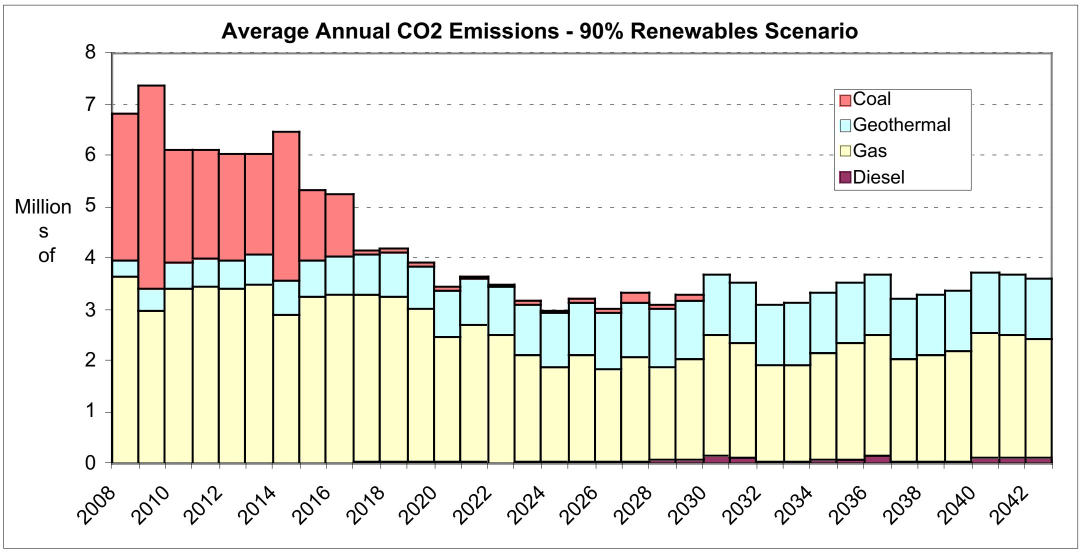

Figure 3.23: Carbon Emissions – 90% Renewables Scenario

These results also suggest that so long as Huntly is available to generate, it could often outbid gas-fired generation when thermal generation is required. With the ready availability of imported and domestic coal and its ability to be stored, diminished availability of gas will open the way for coal-fired generation, resulting in more carbon emissions than would otherwise be the case.

3.9 Demand Forecasting

Load growth is notoriously difficult to forecast, and the forecasts used by the Electricity Commission may be controversial in that they show lower growth rates than have been observed over the last few years. However, for this study, load forecasts are not a critical factor. If loads grow more quickly than forecast, the time scales for the analysis performed here is likely to simply become more compressed. For example, conditions shown as occurring in 2030 will simply occur some time earlier.

3.10 Key Findings from Scenario Analysis

- The government's preferred option for electricity system development is one in which renewables provide 90% of supply by 2025. The policy has some inconsistencies:

  - Geothermal development is promoted as renewable, yet these have significant carbon emissions.
  - Coal-fired plants with carbon sequestration are included, yet this fuel is not renewable.

- The option of a high uptake of gas for electricity generation was not analysed by the Electricity Commission. Their high gas scenario involves major coal fired projects.
- Early replacement of Huntly coal fired generation by gas fired combined cycle plants would give major carbon emissions savings, and would maintain demand for gas for electricity generation at a more constant level throughout the planning period.
- A renewables development strategy and moratorium on the construction of new thermal base load plant has been carried out without thorough analysis. Quantitative economic analysis has not been carried out considering all significant costs and trade-offs:
  - The quantity and cost of fast-acting reserves to cover random variability in wind generation has not been considered.
  - The effect of correlations in wind generation output requiring fast starting plant to provide backup when forecast output from wind generation is low has not been fully included in economic analysis.
  - Transmission grid enhancements and new construction to enable renewables have not been determined, and so these costs could not be included in the economic analysis.
- System short run marginal cost is considerably more volatile in the 90% Renewables scenario than in the other scenarios analysed. This is likely to lead to more volatility in market spot prices.
- To achieve a 90% renewables target, an extra $2 billion in generation plant capital costs are required by 2035, compared to the renewables base case scenario which supplies 80% of energy from renewables by this date. An extra $10 billion is required compared to the high gas scenario.

4 NATURAL GAS

4.1 Markets for Natural Gas

Natural gas is an important and significant contributor to New Zealand's supply of primary energy. It presents a unique combination of attributes in that it is produced from indigenous resources, has a highly reliable delivery infrastructure, and physical properties that permit high levels of energy intensity and delivery with low levels of pollutants. As a fossil fuel, gas emits carbon dioxide but at lower rates than coal or oil products, particularly when used in high thermal efficiency plant such as combined cycle gas turbines (CCGT) for electricity generation.

Since the development of the Kapuni field in the 1970s and Maui a decade later, the contribution gas has made to primary energy supply has increased to a current level of some 20% after peaking at about 32% in 2002. The combined contribution of gas and coal has remained reasonably constant at 34% to 38%.

Gas is used in all energy market sectors although only to a very limited extent in the transport sector which is totally dominated by oil. In other sectors it competes with a range of consumer energy types: biofuels, oil, coal and electricity in the industrial, commercial and residential markets, and with coal, hydro, wind, biofuels and geothermal in the generation of electricity.

The gas market can be broken into three sub-sectors:

Industrial residential and commercial including co-generation

Gas consumption in this group of activities has remained reasonably constant at about 65 PJ per annum and is expected to remain stable with future increases unlikely to exceed GDP growth. Possible step changes could occur with gas discoveries in regions other than Taranaki being made available to energy intensive industries (such as dairy processing in the southern regions) or future distress in the wood or dairy processing threatening the excess of 10 PJ of gas sold into those industries. Co-generation is included in this grouping as a major part of its energy output is used for industrial thermal energy requirements.

Petrochemical manufacture

Gas consumed in this sector is used at Ballance's ammonia/urea plant and at Methanex's export methanol plants at Waitara and Motonui. Whilst Ballance's requirement of 7 PJ pa has remained consistent and is likely to remain so for the next 5 to 10 years at least, gas consumption at the methanol plants has fallen significantly since 2000 and represents the principal reason for the contraction of the overall gas market and the reduction of gas's

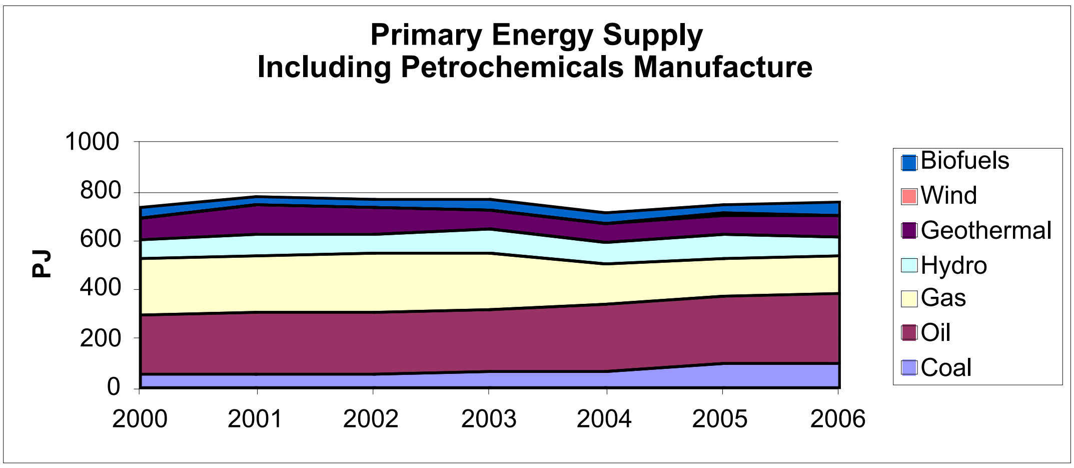

Figure 4.1: Primary Energy Supply Including Petrochemicals Manufacture (source MED)

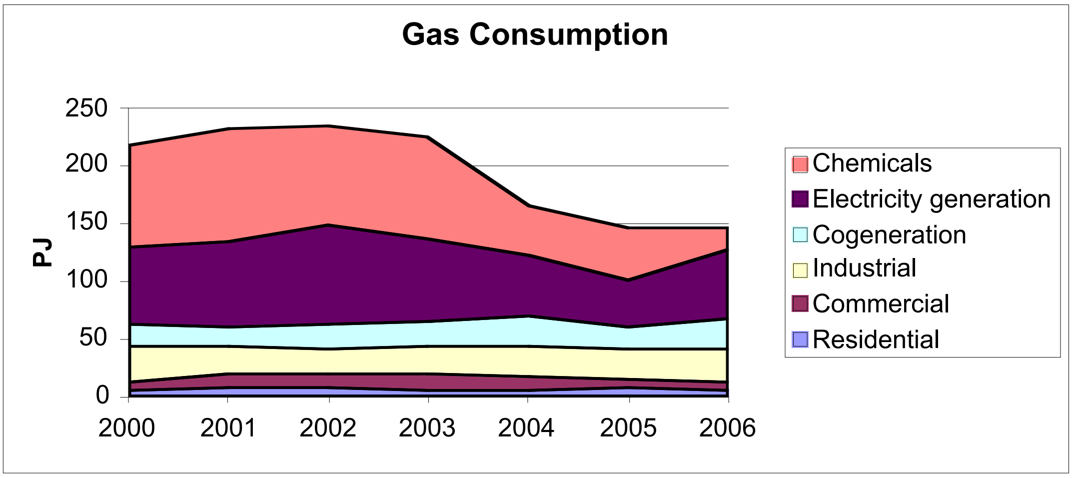

Figure 4.2: Gas Market Consumption (source MED)

contribution to primary energy supply shown in the figures above. Methanex had been drawing its gas from the Maui field at prices set in the 1970s but with the re-determination of the Maui reserves in 2004 this cheap gas was no longer available resulting in the closure of the larger Motonui plant which was no longer economic to run at prevailing export methanol prices.

Recent Asia Pacific prices for methanol have reached levels in the range of US$500 to 700/mt compared with prices of US$300 to 370/mt posted five years ago. These prices are being driven by demand from the expanding Chinese economy with the interest in using methanol as a transport fuel in that country underscoring a strengthening linkage between methanol and oil prices. Interest in exporting methanol from New Zealand has been re-kindled. Methanex recently has been operating its Waitara plant at full capacity, taking 17 PJ of gas, and in January 2008 announced the re-commissioning of one of the two processing trains at Motonui each of which is capable of consuming 35 PJ of gas per annum. It is understood that this train will be run in preference to the Waitara plant. A total potential gas use of 87 PJ per annum at both plants is possible should sufficient gas be available and methanol and oil prices persist at current levels, an outlook favoured by the petrochemical industry.

Electricity Generation

Gas fired power stations produce about one-fifth of all electricity generated in New Zealand, including that from co-generation stations. This

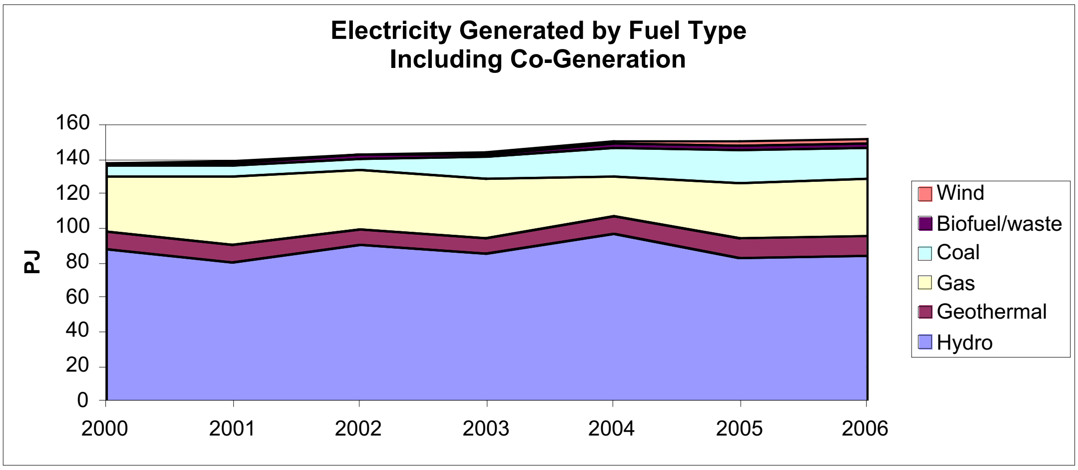

Figure 4.3: Electricity Generated by Fuel Type Including Co-Generation (source MED)

output varies from year to year depending on climatic conditions and the inflow of water into the hydro-electricity reservoirs. Gas effectively acts as the swing input to electricity generation to smooth variations in output from the hydro stations.

Excluding co-generation plants, which produce about 20% of electricity generated from gas, New Zealand has three CCGT stations with individual capacities of about 380 MW, an open cycle station of 40 MW, and two older bi-fuel plants: the oil/gas New Plymouth station and the 1000 MW Huntly power station. The New Plymouth station has recently been de-commissioned and will no longer play a part in electricity supply.

Coal has been burnt at Huntly in increasing quantities over the last few yeas, as can be seen in the above chart as it is the only coal-fired power station in New Zealand. With a significant coal stockpile at Huntly and forward contracts to import further coal supplies, it is expected to consume coal for a few years yet. However, in the longer term gas could be burnt in Huntly in place of coal if gas availability and prices were favourable. This potentially could double total gas use for electricity generation from the typical gas consumption of 60 PJ per annum at the other existing gas-fired stations.

The combined share of generation from coal and gas fired thermal plant has ranged between 27% and 34% of total electricity generated since 2000. Consumption of oil is negligible as it is only used at the Whirinaki peaking station.

There are no firm plans to build new gas-fired generating capacity. Contact effectively has shelved its 400 MW Otahuhu C CCGT project in favour of wind-based capacity after the announcement of government's energy strategy and targets for renewable energy in 2007. Genesis's proposed 360 MW Rodney CCGT station has been put on hold as a result of the moratorium on baseload thermal generation announced at the end of 2007. These two stations effectively were in competition to be the next gas fired power plant to be constructed.

4.2 Gas Supply

Background and Current Climate

For over 25 years the offshore Maui field dominated the supply of gas to the New Zealand market, underwritten by long-term take-or-pay contracts between the producers and the Crown, which in turn sold the gas under back-to-back contracts for electricity generation, methanol production (originally synthetic gasoline) and reticulation to industrial, commercial and residential users. The Crown originally held a 50% interest in the field, through Maui Development Ltd, alongside the original developers, Shell, BP and Todd. During this period, Maui provided a highly reliable source of gas at a relatively low price with a high degree of responsiveness to demand fluctuations. Maui was complemented by the smaller onshore Kapuni field which started production a decade earlier and supplied gas primarily for the reticulation market through NGC, the state-owned gas transportation and marketing company. Other smaller discoveries complemented local

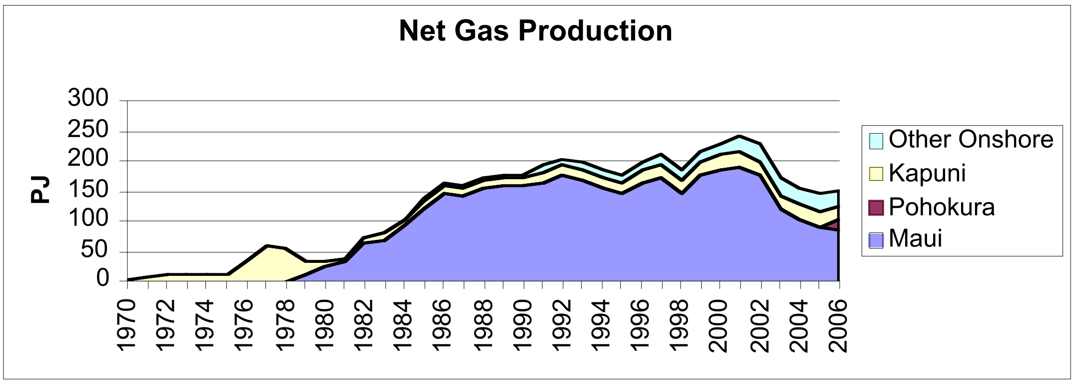

Figure 4.4: Net Gas Production (source MED)

production.

The government's reform and privatisation programme of the 1990s has seen the Crown's interest in the oil and gas sector effectively divested to the private sector, with (ultimately) Shell taking MDL's interest in Maui, Contact being assigned Maui gas for electricity generation and Vector taking over NGC's activities. This period also saw the installation of much of the existing gas-fired co-generation capacity and the first of the CCGT plants by Contact, relieving the impending generation capacity shortfall of the time with new business patterns and technologies, and particularly by utilizing natural gas more efficiently.

This process of change was furthered with the downward re-determination of the Maui gas reserves in 2003 which reduced the total quantity to which the contracts was applicable, with the effect that Methanex's further entitlements were immediately terminated. Since then there have been a number of significant developments which characterize the present-day industry:

- Consumption of natural gas fell to 150 PJ in 2005 and 2006 from highs of over 230 PJ, largely as a result of reduced demand from Methanex.
- The offshore Pohokura field, which was discovered in 2000, was brought on-stream in late 2006 and will reach its expected full output of 75 PJ per annum in 2008.
- The offshore Kupe field is under development and is due to come on-stream in 2008. It was discovered in 1986 and will produce about 20 PJ per annum.
- Additions have been made to the Maui reserves which are now governed by contracts under which Contact and Vector have right of first refusal in a prescribed ratio. A further 270 PJ was added to these reserves in 2006.
- Gas prices have risen to about $6/GJ compared with Maui gas prices in the order of $2.50/GJ. Whilst these are significantly less than international spot gas prices of US$6 to 10/GJ, they were sufficient to drive the development of new reserves such as Pohokura.
- Gas sales and purchase contracts typically are for shorter periods and smaller parcels of gas than in the Maui era. With the opening of the new fields, some gas wholesalers have taken out gas purchase contracts which oblige them to purchase gas in excess of their own requirements for electricity generation and reticulation, creating an apparent surplus of gas in the wholesale market. This situation is expected to persist until 2011/12 when the initial contracts for Pohokura gas will be renegotiated.
- Methanex has re-entered the gas market as the high international methanol prices make the operation of the Taranaki plants viable at gas prices higher than being paid for electricity generation.
- New Zealand has announced its carbon emissions trading scheme which will be applied to electricity generation from 2010, applying an impost on all thermal generation. This is complemented by the 10 year moratorium on new baseload thermal generation and the 90% renewables target by 2025. Already, this policy has seen the shelving of the Otahuhu C and Rodney CCGT proposals.

Gas Reserves

Production of natural gas in New Zealand has been dominated by output from two large fields, Maui and Kapuni, that were developed over 20 years ago and are fairly heavily depleted. These are supplemented by a number of smaller fields with much lower levels of output, in several cases these are primarily oil fields and gas production is incidental, and since mid-2006 by output from Pohokura Field. The Kupe Field is currently under development and will be capable of producing about 20 PJ/year.

The quality of these data is probably variable, and significant changes have been presented and alluded to: for example, there have been substantial upward revisions to Maui field reserves since the 2003 downward redetermination; and Todd Energy have indicated a pending upward revision to the Mangahewa Field reserves (Crown Minerals web site news item. 17/12/07). Revised Regulations promulgated in 2007 should provide a somewhat more consistent basis for reserves compilation in the future.

	Discovery	First Production	Reserves PJ (P50)	Reserves PJ (P50)	Production 2006 PJ
			Ultimate Recoverable Reserves	*As at 1 January 2007*	
Maui	1969	1979	4096	439	87
Kapuni	1959	1970	1112	263	24
Pohokura	2000	2006	898	885	14
Kupe	1986	*2008*	235	235	0
McKee	1980	1984	214	61	7
Waihapa/ Ngaere/ Piakau 3	1987	1990	32	0	0
Kaimiro/ Moturoa4		1983	31	17	0
Tariki/ Ahuroa		1996	129	26	5
Ngatoro5			26	14	0
Rimu/ Kauri6	1999	2002	75	57	4
Mangahewa/Other7			235	190	6
			7083	**2187**	**149**

Table 4.1: Gas Reserves (source Crown Minerals)

These fields are subject to a variety of gas sales and purchase agreements:

Maui: Contract and Vector have right of first refusal for new reserve additions at the Maui field in approximately a 2:1 ratio.

Kapuni: Under a court ruling and since the expiry of the original gas contract, production is now divided equally between the producers, Shell and Todd each 50%, and Vector who acquired the original NGC interest.

Pohokura: The three producer parties, Shell, Todd and OMV, each sell their production separately under contracts with Contact, Vector and Genesis under various terms and pricing.

Kupe: Production is dedicated to Genesis Energy, who are also a party to the producer joint venture operated by Origin Energy.

Other:

- Todd Energy own and operate the McKee and Mangahewa fields, producing about 10% of New Zealand's annual consumption of natural gas.
- Origin Energy, who owns a majority interest in Contact Energy, has recently acquired the assets of Swift Energy in New Zealand. Their onshore Taranaki fields account for about 5% of national production. The purchasers are Contact (Tariki/Ahuroa) and Genesis (Rimu/Kauri).
- Greymouth Petroleum own gas production from the Kaimiro/Ngatoro field complex as well as Turangi, a recent (2006) discovery which is adjacent to and possibly continuous with Todd's Mangahewa field to the south and Pohokura to the north. Greymouth has recently acquired other developed and undeveloped onshore fields including Radnor, which may prove capable of production in the future. The further development of Turangi may lift Greymouth's share of national production from its 2006 level of about 2%.
- Austral Pacific is developing the Cheal oil field and appraising the adjacent Cardiff gas resource with Genesis as a joint venture party. Austral is also continuing appraisal of the Kahili field.

Exploration and development of major new reserves was curtailed during the Maui era as the major markets were tied up by long-term contracts providing virtually no opportunity to develop any major reserves found, such as the relatively high cost offshore Kupe field which was discovered in 1986, but will not come on-stream until 2008. Conversely, some smaller on-shore fields were discovered during this period and successfully developed. Successful gas developments depend not only on the discovery of reserves but also on the business case for development; be they in-field developments at existing fields or through new discoveries either as incremental or proximal developments to existing fields or major new fields and frontier regions. For example, a new CCGT calls for about 15 years of guaranteed reserves deliverable at 20 PJ/year and an offshore development probably needs a plateau offtake of 40-50PJ/year at current gas prices and development costs. Pohokura has been developed by contracting for total volumes of some 100 PJ over about five years and by throttling back Maui production to a corresponding degree.

Because the incentives to invest in exploration, appraisal and development will vary with gas market opportunities and prevailing prices, the generation of new reserves is not a steady process. Since 2000, with the impending decline of Maiu gas production and the increase in gas prices, the incentives have been strong and the rate of reserves generation has been relatively high. The discovery of Pohokura in 2000 added over 800 PJ after its 2003 appraisal and over 430 PJ added during 2006 through the discovery of the Turangi field and the in-field additions at Maui. In contrast, the rate of generation was much slower during the 1980s and 1990s, the so-called Maui era, to the extent that it has taken twenty years for the Kupe field to be developed. Not only does a development business case have to be supported by revenue projections based on prices and gas volumes but also by the timing of the revenue stream. Delays in development beyond the typical 6- to 8-year discovery to gas production lead time can be extremely costly as it proved to be for the entities that made most of the original investment in the Kupe field discovery (see insert).

These developments provide a useful illustration of the differences between reserve additions from incremental field developments and major new fields, particularly in offshore locations. In general, the risks and expenditures involved in exploration and development of major new fields will be higher than for incremental development of existing fields or areas close in to existing developments where the geology and petroleum-bearing potential is better understood from the outset. Also, where gas is associated with crude oil production, as at the McKee field, the economics of gas production are significantly enhanced. The history of the New Zealand gas industry reflects these trends with the occasional development of offshore fields to fit with market demand along with the more regular development of on-shore fields such as McKee.

New Zealand still presents considerable opportunity for discovering new gas resources. This exists at the major fields, where Maui has already yielded blocks of 100+ PJ and there is potential to revise both Pohokura and perhaps Kupe upwards, and at the on-shore fields where Kapuni can be upgraded with in-fill drilling and the Mangahewa/Turangi development is indicated. Offshore Taranaki exploration provides potential as do the frontier areas such as the Great South Basin which remain very lightly explored.

In the preparation of the New Zealand energy strategy, the government takes a more pessimistic view of the rate of gas reserve development. Its modelling assumes that the rate of reserve generation is 60 PJ per year based on the historical average excluding the Maui field. This presents an unrealistic view of the performance of the gas exploration industry as it includes a lengthy period when Maui dominated the gas markets and there was little incentive to develop major new reserves. In recent years, with strong incentives for reserves development, the rate of increase has been much higher.

Gas Production Potential

Based on reserve estimates of existing fields and potential field production outlook, a profile of gas delivery has been developed which indicates that a production level of 180 PJ can be sustained from 2010 to 2015/6 when a gradual decline in output from existing fields will commence. Existing fields must be complemented from this time by reserve additions and the discovery of new fields to sustain the gas industry's ability to supply the New Zealand markets.

This profile has been arrived at using a number of assumptions:

Suppressed Gas Markets will Curtail Exploration for Gas

The time between the discovery of gas and first production can have a major influence on the economics of gas field development from the perspective of the venture which makes the original discovery. Perceived risk of delays in bringing a field on-stream will deter companies from investing as heavily in exploration. Consequently, any government policy which delays or curtails access to gas markets will inevitably lead to a reduction in exploration activity and the booking of new gas reserves.

The impact of a delay on gas exploration economics is illustrated in a discounted cash flow valuation model of a hypothetical offshore Taranaki gas-condensate field of approximately the size and characteristics of the Kupe field (see Figure 1).

The gas field is modeled to have been discovered as a result of an exploration investment programme initiated in 2008 and costing about $100 million until the time when the reserves are appraised sufficiently to underpin a final investment decision for field development. There is sufficient gas production to meet the needs of a 400MW CCGT power station for at least 15 years, and if this had a ready market for its output and the field was developed expeditiously according to the investment schedule shown, the net present value of the prospect would justify the exploration investment so long as its probability of success was at least one in five (ie, NPV is about five times the cost of discovery and appraisal).

However, as shown in Figure 2, if development was delayed just 5 years due to insufficient gas demand in the market, the net present value drops by over $100 million. Payback is delayed by eight years, and the exploration investment decision would only be rational at a probability of success better than even, which would be unacceptable for most exploration companies in the New Zealand context.

A ten year delay between discovery and appraisal, and first production, generates a negative net present value.

This comparison of an exploration business case with and without an imposed

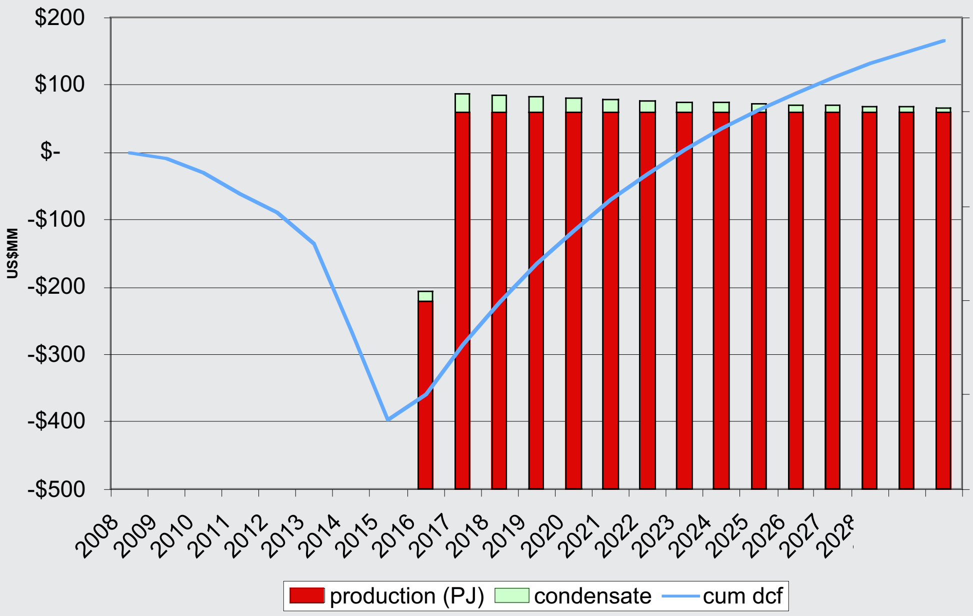

Figure 1: Cumulative Discounted Cash Flow and Production Profile

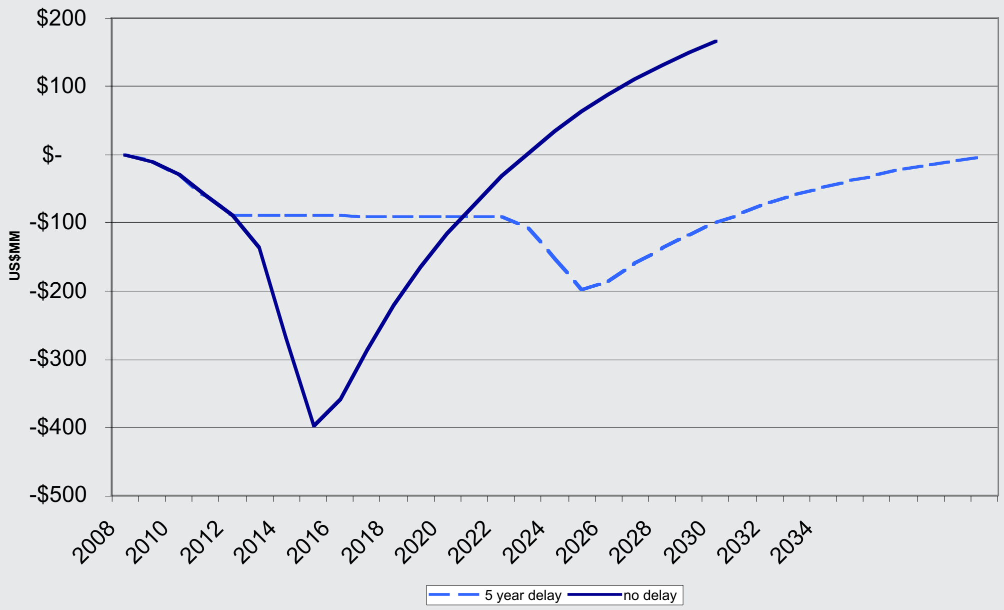

Figure 2: Delayed Cumulative Discounted Cash Flow Profile

constraint on the ability of the New Zealand energy market to absorb a new gas field development through new thermal power generation illustrates the likelihood that exploration investment directed at gas discovery will not be forthcoming as a result of the 90 per cent renewables policy.

Policy makers should not assume that the gas exploration and production sector can recover from the systematic curtailment of its market. It is already being forced by natural depletion into more and more remote and difficult settings with progressively greater costs and longer lead-times between initiation of exploration and delivery of gas. Taking away, or deferring by several years, the most likely date of first sales revenue destroys the incentive to explore no matter what the prospectivity or price expectations.

- Kupe will produce 20 PJ per annum and is assumed to be the first despatch due to the attributed length of contract. This will be subject to the field performing to expectations.
- It is estimated Pohokura produced 68 PJ in 2007 and is assumed to produce a constant 75 PJ/year until currently-booked reserves of 884 PJ (1/1/07) are exhausted. Reserves additions are likely to extend the tail.
- Maui is treated as producing a minimum of 40PJ/year until currently indicated reserves (665 PJ @1/1/07 inclusive of assumed ROFR quantities) are exhausted. Further reserve additions are possible.
- Onshore capacity is dominated by Kapuni and assumptions about Mangahewa and Turangi based on recent announcements. This capacity could be extended or prolonged with exploration success.
- Lower-level balancing is accommodated by curtailing onshore production, but in practice this may be done at Maui.

These assumptions can be subjected to a number of permutations, which in practice will see the profile alter and in all probability see the production tail extended. In particular, reserve additions will be made and the present Pohokura contracts expire between 2010 and 2016, with a possible re-balancing of the market resulting in Pohokura production being curtailed at the expense of Maui and/or onshore sources. An extreme case would be the curtailment of Maui to the point of premature abandonment, unlikely to occur as the petrochemical sector will be allowed and able to intervene to restore consumption.

Figure 4.5 illustrates a possible outlook for future gas production overlaid with gas demand under the High Gas scenario for electricity generation discussed below. The figure highlights the inevitable decline of existing fields and their replacement through new addition and discoveries, representing reserve development under favourable market conditions.

Failure to provide an adequate policy environment to encourage the investment necessary for gas reserve development runs the risk of overall reserve depletion and shortfalls of gas supply against market demand. Figure 4.6 illustrates a pessimistic case where investment is suppressed because of curtailed market demand and insufficient reserve generation occurs.

4.3 Gas Industry Outlook

The announced New Zealand Energy Strategy signals government's intention to pursue

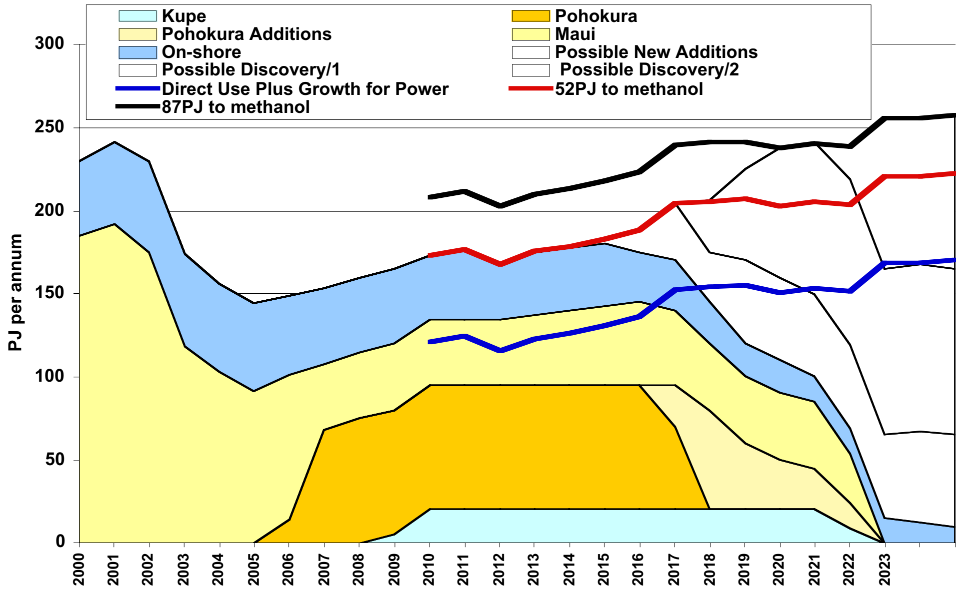

Figure 4.5: Gas Production Outlook: High Gas Case

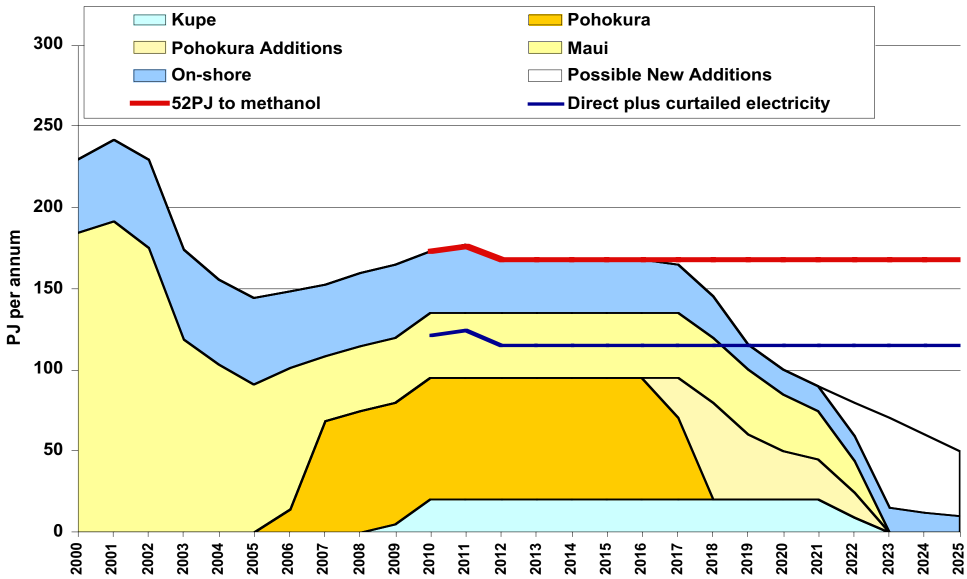

Figure 4.6: Gas Production Outlook: Curtailed Market Demand

policies designed to increase the contribution of renewable fuels to the supply of primary energy and, in particular, to the generation of electricity. By implication the contribution of natural gas will likely be reduced. The effects of this are discussed in the commentary below.

Government analyses are set out in the papers accompanying the NZES and also from the Electricity Commission. These papers paint a somewhat pessimistic impression of potential gas reserves and present a consistent view of gas being under some considerable constraints.

An important theme of the earlier discussion is that reserve addition is responsive to demand for gas and the business cases to carry out exploration and to appraise and develop discoveries. Government appears not to have taken such drivers into consideration when developing their gas picture which generally focuses on consumer energy forms such as electricity rather than primary energy supply to which natural gas is a significant contributor.

Linkages Between the Gas and Electricity Sectors

Electricity generation is a key market for natural gas which is directly affected by the government's Energy Strategy. This study investigated four scenarios to illustrate the relationships between the gas and electricity sectors and policy. These are discussed in detail in the accompanying report on the electricity sector but are outlined below to illustrate the effects of different policy settings on the gas industry and in particular the demand for gas in electricity generation.

Base Case

This is the base case scenario used by the Electricity Commission in the government's analysis of energy policy. With regard to gas, it places a restriction of 75 PJ per annum for electricity generation and raises gas price from a current level of $5.5/GJ to a ceiling of $10/GJ in 2020. Coal price at the Huntly power station is $4/GJ throughout. Estimated gas consumption remains at more or less the same level as today but falls to 45 PJ pa in 2020 as it becomes cost effective to burn coal at Huntly before rising to 70 PJ when the Huntly station is assumed closed in 2020. Carbon emissions are relatively high due to the burning of coal at Huntly.

High Gas Case

This case assumes no restriction of gas use through policy or carbon emissions. Gas prices and carbon charges are set sufficiently low at $7/GJ and $15/tonne respectively to make gas the preferred option for new generating capacity with new CCGT stations regularly brought online from 2011. Under these circumstances gas use for electricity generation is forecast to rise to about 120 PJ per annum in 2030, about double the current contribution.

Whilst this might appear to contradict the discussion regarding the gas production outlook based on existing reserves, it is not unreasonable considering the response of the gas industry to meet the potential generation shortfall during the 1990s and the significant increase in gas reserves during the 2000s when additional reserves were urgently required. However, this represents a high carbon emissions case as there is also no restriction on coal use.

Huntly Early Retirement

This case has been included to address the high carbon dioxide emissions implicit in the high gas case by retiring the coal units at the Huntly power station from 2017 or putting them on reserve status. Gas prices and carbon charges assumed to be as is the base case and the Otahuhu C and Rodney 1 CCGT plants commissioned. Under these circumstances, carbon emissions would be cut to about half those in the high gas case and gas consumption sustained at 70 to 80 PJ per annum through to 2030. This case represents a sustained gas market with relatively low carbon emissions. However, it does imply a restraint on the use of coal for electricity generation.

90% Renewables Case

The imposition of the 90% renewables target will result in a greater investment in renewables generating capacity in the shorter term than would have been the case if the target had not been applied despite the capital costs of renewables capacity being higher than gas-fired capacity. Existing thermal plant will not be able to compete with this renewable capacity as the bidding into the electricity wholesale market is done on the basis of short run marginal cost, which is near zero for renewables and necessarily higher for thermal plant as the direct cost of fuel at least must be included in its SRMC. Not only will the moratorium prevent the construction of new thermal plant but also the 90% renewables target will make it more difficult for thermal fuels to find a place in the electricity market. Gas use for electricity generation is forecast to fall to 40 PJ in 2023 compared to its present level of 60 PJ per annum and the Huntly power station to close in 2016, closing off a significant market for gas and coal.

The 90% renewables case effectively has been occurring for over six months with the derferral of the Otahuhu C and Rodney projects.

The range of gas consumption in electricity generation from the scenarios discussed above is shown in Figure 4.7.

It is apparent that a significant range of outcomes is possible depending on the policy settings assumed with the differences being of sufficient magnitude to affect the prospects for the gas industry. Whilst the upper levels of gas consumption may not necessarily be attainable under current political sentiment for carbon emissions, this analysis does demonstrate that the 90% renewables target will have a negative effect on the gas market. Some intermediate policy might provide an optimal outcome.

Future Gas Demand: Non-Power Sectors

There are three periods of interest when considering the future of the gas industry:

- The period up to 2011/2012 during which gas production is largely contracted to wholesalers to a level in excess of the requirements of the electricity generation and the industrial (including Waitara Valley methanol, Ballance fertiliser), commercial and residential markets.
- From 2011/2012 until about/at least 2018 where a similar excess capacity of gas will be available, but up to half has yet to be contracted.
- After about 2018 gas availability is predicted to fall below market requirements, largely due to the decline of the Pohokura and Kupe fields, unless significant new sources are discovered and developed, and/or reserve additions eventuate within existing fields.

It should be noted that the absence of very long-term reserve cover does not represent an unusual or unsatisfactory situation. The gas sector is used to operating in this environment and the implicit uncertainty is germane to petroleum exploration activities. However, it is important that the balance between risk and reward is not adversely skewed by inappropriate policy intervention.

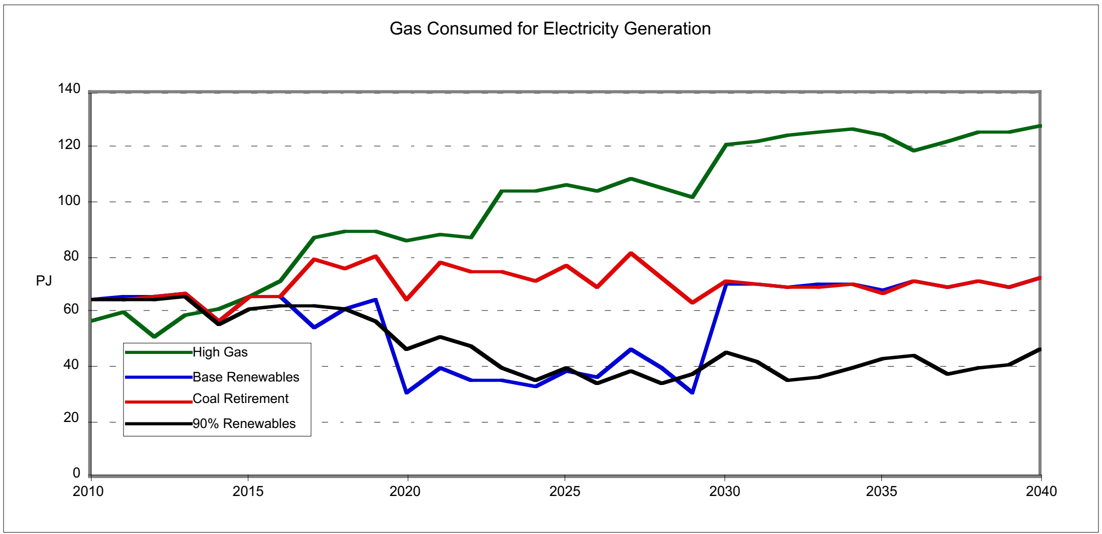

Figure 4.7: Gas Consumed for Electricity Generation

Outlook 2008 to 2011/12

Into the short term, gas wholesalers hold a surplus of contracted gas over their own requirements and will be seeking markets for this surplus gas volume, which could rise to about 50 PJ per annum by 2012. There are limited options for selling this gas, with Methanex best placed to pick up surplus volumes.

- The industrial, commercial, residential and co-generation markets which presently sit at some 65 PJ per annum and are not expected to rise more than the GDP rate. They represent a stable, high value gas market. The stable 7 PJ offtake of Ballance can be added to this volume.
- Methanex is already active in purchasing significant quantities of gas over relatively short terms whilst methanol prices make the operation of the Taranaki plants profitable. The recent announcement that Methanex will re-commission one of the Motonui methanol trains indicates that it expects to remain in the market for at least four to five years, taking at 35 to 60 PJ of gas each year. This represents about 200 PJ which would be lost to power generation.
- The principal impact of the moratorium over this period is the prohibition of any new gas power plant such as Rodney.
- The Huntly power station is a potential competitor for this gas but is unlikely to purchase significant quantites because of its commitments to purchase coal and the likelihood that Methanex can dictate a more competitive gas price.
- Gas storage or leaving the gas in the ground provide little opportunity to dispose of the surplus during this period. No significant storage facilities are expected to be available before 2010 and, with contracts in place, buyers and sellers generally will be motivated for gas to be produced in the market. Kapuni could be run to meet demand so may represent some small opportunity to curtail production but is unlikely given its consistent history of production. It may be possible that the right of first refusal buyers at Maui could forego offtake but would have little motivation to do so, given Methanex's activity and the likelihood the foregone gas could be taken up by competitors.
- Gas wholesalers will be looking forward to obtaining sufficient gas for their thermal plant once the existing contracts expire and will be strategising their integrated position in the gas and electricity wholesale and retail markets under the renewables environment. A major consideration will be maintaining energy sales volumes which will depend on market share growth in the low or negative growth scenario favoured by policy.

Throughout this period petroleum companies have little motivation to discover major quantities of gas as there is no apparent market within typical lead times for development unless additional gas power generation capacity can be added or a continuous market found for gas at Huntly. In the case of the moratorium, with suppressed gas demand, E&P companies will be faced with the likelihood of a receding horizon for the development of significant new gas reserves to replace existing fields. This will be exacerbated by uncertainty about the scope for and timing of possible reserve additions in existing developed fields, especially for exploration companies with little or no production. These uncertainties surround Maui, onshore Taranaki fields such as Mangahewa and Turangi, and Pohokura for which an upgrade seems likely but producers, in the absence or weakenss of regulatory mandate, seem likely to withhold until after the next set of contracts 2010-11.

There is also scope for downward revisions, probably mainly in relation to Kupe.

The most likely outcome is that a substantial portion of gas readily available through this period from existing sources and the Kupe field will be taken by Methanex rather than reserved for future power generation or other high-value uses. It is not expected that there will be upward pressure on gas price in this period.

Outlook 2010/12 to 2018

At the beginning of this period, the current market surplus of gas will be rationalized as existing contracts are re-negotiated and options for selling gas or otherwise disposing of it increase. Potential gas production will be about 180 PJ until the end of the period when output starts to decline based on current reserve estimates. It therefore represents the next crucial period wherein the next tranche of new gas reserves must be developed to sustain the gas industry and also contains the minimum leadtime to develop these reserves from the time of discovery.

In reality the decline of output will not be so clearly defined as the figures in the report suggest as gas reserves and usage patterns will adapt to market circumstances. However, it is important to note that the minimum leadtime to development commences not now but in five or ten years hence.

- Industrial, commercial, residential and co-generation markets will continue to draw about 65 to 70 PJ per annum plus a continuing 7 PJ offtake by Ballance.
- As in the previous period, Methanex is expected to continue to be in the market for significant quantities of gas over short periods as they are operating at present, taking parcels of gas when it is profitable to do so.
- In the electricity sector the effect of the moratorium on gas consumption becomes more pronounced.
- Gas storage represents a possible means of disposing of any excess gas. The Ahuroa storage will be commissioned at the start of this period with other possible storage options also under consideration. These can be used to provide gas delivery spikes or provide some term storage although it is anticipated that this will have a relatively small capacity and come at a significant cost premium. Storage will have to have to compete with leaving gas in the ground.
- The renegotiation of gas contracts provides an opportunity to leave some gas in the ground by reducing quantity and extending contract periods. This most likely will come at a price premium and is a more probable option with the moratorium applied as more surplus gas will be available.
- During the early part of the period gas wholesalers will be looking to contract sufficient gas for their thermal plant and direct gas markets. Without new reserves added, they may shift their emphasis away from the gas as there are other options in the power sector supported by government policy, as evidenced by Contact's shift to a renewable power proposal during 2007. Whilst gas supply to the industrial, commercial and residential market will remain a continuous and valuable market, they may look to replace domestic gas with LNG, oil, coal etc. Also, it might be expected that the price of energy may stress some industry sectors and reduce demand. Already there is anecdotal evidence of deferral in new capital investment in some energy intensive firms because of uncertainty.

This is an important time for gas exploration and development activities. The lookup becomes increasingly uncertain unless new discoveries are made:

- a shrinking market if the moratorium is applied, compounded by any negative growth in major industrial sectors.
- increasing opportunities and incentives for gas developments as the horizon for bringing new gas into the market approaches.
- a commensurate risk that gas consumers and wholesalers will switch to other sources of fuel such as LNG or coal if gas is not discovered in time. Gas prices would be expected to rise to about $10/GJ in this situation as reserves depleted.
- Discovery of new reserves will ease pressure on gas prices with levels dictated by location, cost of development and quantities of gas and associated liquids. In probability, new prices will be similar to those currently in the market, unless the gas comes from frontier regions such as the Great South Basin where development and transportation costs will contribute to costs of $10+/GJ in the North Island markets.

Outlook 2018/20 onwards

Based on current reserves estimates and anticipated gas offtakes for all scenarios, all the significant gas fields with the possible exception of Kapuni, are expected to decline over this period resulting in a major shortfall between production and demand. In reality, this situation will not be so clear-cut as reserves may be added to, as suggested in Todd's December announcement regarding Pohokura and Mangahewa, or reduced and production will shift to some extent to match demand. Whilst there is some analogy to the post-Maui situation, there is probably less potential for a reserve upside because of the sheer scale of the Maui field.

The only means of remedying this situation will be the addition of significant new gas reserves through an active exploration effort in an environment conducive to their appraisal and the financing and construction of production facilities. Without these new reserves, energy demand will switch to oil, LPG and coal, with a commensurate increase in greenhouse gas emissions, or the importation of LNG, or not be met, with the closure of certain industries as happened with methanol from 2003. This impact will be felt by the whole natural gas industry, not just for gas supplied for electricity generation, which comprises only about one-third of the total gas demand.

The principal impacts of the moratorium start to be manifested during this period with gas consumption falling to 100 to 110 PJ per annum plus any sales to the petrochemical sector. The overall impact will be a contraction of gas volumes into the electricity sector to about 40 PJ with a shift to more gas quantities required for non-baseload generation to support the uncertainties implicit in generation by renewables. Gas is also implicitly required as a default should the security of supply exclusion be invoked or long term technologies such as CCS not prove viable.

The importation of LNG remains a longer term option to replace domestic gas if no significant addition is made to reserves. Under current conditions a minimum scale of LNG importation is in the order of 60 PJ per year with long term contracts being the normal basis of supply.

This is at odds with the scale of the New Zealand gas market and the fragmented nature of gas contracts, making the prospects for LNG in New Zealand not high at present as introducing a large block of gas over a short period of time will be a complex task. In addition, an LNG solution would require a stimulus to gas consumption exactly counter to the effect of the present policies

However, trends in the contracting and scale of activity in the international LNG market (or CNG) may suggest that this might not necessarily be the case in 10 to 15 years time. Also, LNG shares with domestic gas the same greenhouse gas benefits compared to oil and coal so may curry policy favour sometime in the future should no further gas be discovered.

In any event, the scale of LNG importation represents a threat to the domestic E&P industry as it would potentially close out a very significant proportion of the New Zealand gas market.

4.4 Impact of Policy on the Gas Exploration and Production Industry

The Climate Change Bill

Supporting documentation to the Bill provides insight into the government's objectives for adopting this legislation:

- Government recognises the possibility that gas-fired generation could be cheaper than renewables energy under the ETS and would be selected preferentially over renewables. The moratorium is explicitly intended to prevent this possibility.
- Government perceives the importation of LNG as a risk and believes that the moratorium, by resulting in less gas plant capacity being constructed, will reduce the possibility that LNG will be imported in New Zealand. In the government's opinion, this is a favourable outcome as LNG importation will tend to uphold the position of fossil fuels in the primary energy mix and reduce the demand for local exploration.
- The government's view of the moratorium's impact on exploration for gas reserves appears to be ambivalent but indicates that any impact will be principally on the offshore North Island and exploration in frontier areas such as the Great South Basin will be unaffected as exploration targets will be large and of interest mainly for export.
- Although the EC wind integration study indicates that high levels of wind generation will pose significant problems for the electricity supply system, the government believes these can be resolved in time. Also, the studies indicate the need for CCS after 2030 which the government believes will be met by gas or hydro if CCS technology does not evolve. There is no mention of the need to sustain the gas industry in

the interim.

- Government believes any perceived security of supply implications can be overcome by the exclusion provisions.

Response of the Gas Exploration and Production Industry

A commercial business case for oil and gas exploration investment requires a future demand profile for its potential output at a price sufficient to under-write the costs of discovery and development. The present New Zealand gas market can be placed in three segments:

- The industrial, commercial, residential and co-generation markets which will remain a steady, high value marketing the range of 65 to 75 PJ per annum
- Methanex will continue to be active in the New Zealand gas market buying substantial quantities of gas for short terms. Prices paid for gas will depend on international methanol prices but, whilst competitive with electricity generation at present, will be dependent on international markets and uncertain in the longer term.
- Electricity Generation consumption is subject to electricity sector policy but under the 90% renewables target is estimated to fall from a current level of 60 PJ to 40 PJ per annum.

Of the three markets outlined, power generation represents the best opportunity for significant, new and secure long-term market opportunities. Power generators prefer gas fuel for thermal new capacity on the grounds of cost, utility, and cleanliness. Without this market, exploration companies face a period of over 10 to 15 years without an outlet for new discoveries until the output of existing fields starts to decline. As it usually takes 5 to 10 years to bring significant new gas discoveries to market, this places a window within which discoveries must be made: discoveries before that time will be premature and will lie idle before development whilst later discoveries stand to be pre-empted by a market shift to other energy resources.

The absence of ready growth in the market for gas leaves the exploration industry in a situation analogous to that which pertained whilst Maui was at full production. During that time the exploration effort was suppressed as abundant and cheap Maui gas closed the market to new gas in the same way. The effect of a constrained market is exemplified by the Kupe and Maari fields which were discovered before the market was ready for them and were financial disasters for the companies which made most of the investment in their discovery. Conversely, the Pohokura project has been an excellent success because of the short lead time to development and escalation in gas prices at the time. There is no guarantee that such a timely discovery will be made as Pohokura itself starts to decline and the lack of a rational business case for exploration will reduce the probability of this being achieved.

The thermal generation moratorium and renewables target provides such a constraint on the gas market. Consequently, it will lead to a suppression of exploration activity and reduce the likelihood that domestic gas resources will meet New Zealand's future needs for thermal fuels and a globally competitive energy system. Of particular concern is the fact that this effect will be masked over the next few years whilst a surplus of gas is available to the market and before the greenhouse gas emissions trading scheme for electricity generation commences in 2010. The crucial time for exploration is the next five to ten years so any impact resulting from incorrect policy signals now will not be felt in the energy markets until well into the next decade by which time the markets will already be starting to adjust in anticipation of a gas shortfall. It will be too late to fix the problem. This exacerbates the uncertainties for the exploration companies and potentially undermines some of the assumptions and benefits used to justify the moratorium:

- Thermal fuels will remain a necessity for electricity generation with gas having significantly lower carbon dioxide emissions than the alternatives of coal and oil. Any failure of the gas industry to supply the electricity sector will result in higher emission levels. A possible alternative will be the importation of LNG, which government perceives as a risk and poses a threat to the domestic gas exploration and production industry.

- Constraints on gas supply could impact on the industrial, commercial and residential markets which are of similar magnitude to the current electricity market for gas. Consumers will switch to electricity, coal or oil with commensurate increases in carbon dioxide emissions. It is anticipated that these will be the last gas markets to be retained because of their traditionally high values.
- Thermal fuels hold a default position in the renewables strategy as a standby in the event of the exclusion provisions being applied or gas being used should CCS technology not be viable in the later part of the renewables programme. No cognizance is given as to how the gas industry will be sustained to be responsive in this backup role, which conflicts with the government's intention to reduce gas's broader contribution to the power sector.
- It cannot be assumed that continued interest in exploration for oil in New Zealand will necessarily carry over to an increased yield of gas discoveries. The petroleum industry makes a distinction between oil and gas prone areas and can bias its activities toward oil discoveries if markets for gas are uncertain. Furthermore, gas exploration effort can be directed at areas near current reserves where prospectivity might be high but potential reserves are small as has been done in onshore Taranaki. Ventures will look to hold permits over geologically attractive areas in the hope that they may find fields which could be economic on their oil production; and in respect of gas, will entertain the hope that the policy will prove unsustainable. Bidding for permits, and undertaking geological and geophysical studies may well remain as rational commercial strategies notwithstanding the proposed ban on the use of gas for any new base-load electricity generation projects; but actually drilling for gas prospects is likely to be avoided.
- As the principal impacts of the 90% renewables policy occur after the domestic gas industry needs to re-establish its reserve base, the moratorium potentially will act as an impediment to gas taking its place in the government's energy strategy. This risk should be compared with the low risk ascribed by government to the uptake of gas in preference to renewables.
- The 90% renewables policy requires increased thermal generation on a stand-by basis. It should be noted there is no business case for stand-alone intermittent stand-by gas production. Gas supply is provided on the basis of sufficient price, quantity and timing to meet costs of field development and operation. Holding gas on standby is only possible if it is associated with a base minimum gas flow to provide minimum revenue to the supplier and is incorporated in most gas sales and purchase agreements through the nomination of minimum short and long delivery quantities. These may be specified on hourly, daily, weekly or annual bases with the average rate of delivery diminishing with the length of the period.
- The objective of the 90% renewables policy is to force commercial decision makers to follow a particular pathway to developing generation capacity. This is a step change from the non-intervention policy and the use of economic instruments which has been the hallmark of government policy of the last 20 years. During this period, the gas industry has successfully provided additional generating capacity to the national inventory and added gas reserves in the post-Maui environment. A reversion to interventionalist policy can upset the balance of risks and rewards necessary to the exploration and production industry and presents a clear risk of further disincentivising these activities.
- The focus of government energy strategy has been consumer energy, in particular electricity generation. Gas is not only a contributor to consumer energy but a significant and stable contributor to primary energy, despite being a relatively small industry in terms of participants and direct impact on consumers. In this context, the strategy tends to convey a somewhat pessimistic impression of potential gas reserves and presents a consistent view of gas being under some considerable constraints due to a lack of longer term reserve cover. It must be stressed that the petroleum sector is used to operating in this environment and the development of new reserves is an implicit part of its business when the appropriate opportunities and incentives are available.

- The energy strategy acknowledges energy security as a key concern with gas, along with other thermal fuels, having a back-up role in the case of failure of renewables technology. In this context, security of supply from the gas industry and consequently as support to electricity generation cannot be measured only in terms of existing reserves. An equally important measure of security of supply is the existence of a viable petroleum industry incentivised to add to these reserves.

There are a number of other significant points which relate to the performance of natural gas and the gas industry.

Proven Record of Gas Industry

The natural gas industry has been operating in New Zealand for over 30 years. The nature of the industry and its performance is well understood. In particular, gas quality, availability, performance of plant, its costs and environmental impacts can be quantified with a high degree of confidence. In comparison, the performance of renewable technologies is subject to greater uncertainty, either through climatic uncertainties or the novel nature of the technology.

The upstream oil and gas industry is used to operating in an environment of reserves uncertainty and the generation of new reserves through E&P activities is an integral part of the industry. Gas has been quick to adapt to previous energy supply concerns, for example the filling of the generation capacity 'gap' in the 1990s through the introduction of CCGT technology.

Diversity of Primary Energy Supply

Diversity of energy supply is an important element in energy policy. Any reduction in the role of gas in the primary energy mix will inevitably reduce the flexibility of the energy markets to adapt to any future changes or new priorities in policy which are not foreseen at present. Because of their complementary nature and potentially similar role in energy supply, the most likely replacement for gas will be coal, which results in higher carbon dioxide emissions in any situation. If a major gas discovery is made sometime in the future, the possible re-instatement of gas after a hiatus in its use could be problematic because of the difficulty in matching a large resource development with the small size of the New Zealand energy market.

Reliability of Gas Supply

Natural gas has been delivered to the residential, commercial and industrial markets in the North Island for over 30 years with a high level of reliability. It is also a major source of primary energy for the generation of electricity and gas supply has to conform to the reliability criteria of that industry. This reliability is underwritten by a transmission and distribution system built to recognized construction and operating standards with gas deliverability based on established field reserves. Failures of the gas supply system have been very infrequent and quickly rectified.

Delivery of gas is not affected by factors outside the gas field and delivery system whereas the availability of renewable energy is directly influenced by the climatic conditions and competition for natural resources. Gas effectively is used as a standby for hydroelectricity in dry years when there is insufficient water in the hydro reservoirs to meet demand and wind and solar energy systems must be complemented by more reliable generation capacity using fossil fuels.

New Zealand Energy Strategy

Natural gas is recognised in the New Zealand Energy Strategy as having continued importance as a source of primary energy with gas seen to continue to play an important role in meeting energy supply requirements during transition to the "sustainable energy future ... in which supply is increasingly met by renewables" and will play a key role in maintaining security of supply in the electricity sector. However, the NZES does not have a parallel strategy to ensure other forms of energy will fill any shortfall in renewables uptake. The most likely candidates to fill this gap are the existing fossil fuel suppliers who are provided with uncertainty and little incentive in the strategy to continue with the investment necessary to maintain their businesses. This creates a new vulnerability in the New Zealand energy market.

5 CONCLUSIONS

CAENZ has carried out a review and analysis of the impact of the government's thermal generation moratorium and 90% renewables target for electricity generation. This has been undertaken using the government's own analytical tools and extended to assess the likely impact of the policy on the petroleum exploration and production industry, based on its performance in New Zealand since the development of the Maui gas field. In this context, the review is grounded in the same assumptions as those used by government but contains a more detailed examination of the likely implications on an important part of the thermal fuels industry. The principal conclusions CAENZ has drawn from this review and analysis are summarised in the following paragraphs.

The renewables policy exposes the electricity system to increased uncertainty and increases the risks to electricity security of supply. Thermal energy makes an important and growing contribution to electricity generation, providing reliable diversity of supply to complement the natural uncertainties implicit in the generation of electricity by wind and hydro. This contribution presently sits at about one-third of all electricity generated in New Zealand. A reduction to 10% represents a significant reversal of the current trend and a high proportion of wind generation, as will be the case with the 90% renewables target, raises significant issues of system security and for the timely availability of thermal fuels to back up the intermittent nature of wind energy. Of the two principal thermal fuels used for electricity generation, gas can be used more efficiently and with significantly less carbon dioxide emissions than coal, and will be the preferred thermal fuel unless economics dictate otherwise.

The renewables policy, by reducing demand for gas in electricity generation, increases the risk of the petroleum industry failing to provide adequate gas resources necessary to back-up renewable generation in the future. Continuity of market opportunities for gas is a primary incentive for the on-going investment in exploration and development activities necessary to provide new gas reserves to replace existing reserves as the latter inevitably decline. A reduction in gas demand for electricity generation will result in an overall suppression of the New Zealand natural gas market, leading to a disincentive for companies to make these investments, particularly in the short- to medium-term. Whilst exploration activities may continue and exploration permits continue to be issued by government, limited market opportunities will inevitably result in lower intensities of exploration expenditure and reduce the likelihood that well-funded upstream operators will continue to be attracted to New Zealand. These effects reduce the probability of finding new gas reserves, resulting in increases in gas prices to the advantage of coal with its higher level of emissions.

The New Zealand petroleum industry has shown itself to be capable of adding new gas reserves when necessary and when the appropriate incentives are available. In contrast, the New Zealand Energy Strategy conveys a somewhat pessimistic impression of potential gas reserves and presents a consistent view of gas being under some considerable constraints due to a lack of longer-term reserve cover. Since 2000, with the impending decline of Maui gas production and an increase in gas prices, the incentives have been strong and the rate of reserves generation has been relatively high with the discovery of Pohokura and Turangi and in-field additions at Maui. Conversely, the rate of generation was much slower during the 1980s and 1990s, the so-called Maui era, to the extent that it has taken twenty years for the Kupe field to be developed. New Zealand still presents considerable opportunity for discovering new gas resources. This exists as upside potential at the major fields and in offshore Taranaki and frontier areas such as the Great South Basin which remain very lightly explored. The petroleum sector is used to operating in an environment where gas reserve cover is short or uncertain and the development of new reserves is an implicit part of its business when the appropriate opportunities and incentives are available.

The government's preferred option for renewables providing 90% of electricity supply contains some inconsistencies with its own analysis and energy sector experience:

- The moratorium on new thermal generation has been put in place to pre-empt the uptake of new thermal plant instead of renewables generating capacity. Government places a low probability on this happening in practice. However, an examination of the case studies shows that thermal generation is a clear least cost option and would be taken up in a market without regulatory constraint.
- Government's analysis of cases with lower levels of renewables uptake, including the high gas case, involves major coal use, resulting in high levels of carbon emissions. The selection of coal in these cases is based on arbitrary assumptions on the relative prices and availability of gas and coal, whereas in practice the gas industry will endeavour to set prices to out-bid coal suppliers. This analysis therefore shows a disproportionately high level of carbon emissions in cases with levels of renewables uptake of less than 90%.
- Government assumes that the rate of new gas reserves generation is 60 PJ/year, based on an historical average but excluding the Maui field. This presents an unrealistic and pessimistic view of the performance of the gas exploration industry as it includes a lengthy period when Maui dominated the gas markets and there was little incentive to develop new reserves. In recent years, with strong incentives for reserves development, the rate of increase has been much higher.
- Government's 90% renewables case includes significant expansion of geothermal capacity, which has significant carbon emissions, and coal fired plants with carbon sequestration. Neither of these technologies sits comfortably within any definition of renewable energy, bringing into question the feasibility of reaching the 90% target.

The government's analysis of the renewables development strategy and moratorium on the construction of new thermal base load plant is incomplete. This has resulted in government presenting an optimistic case for maximising the renewables contribution to electricity generation when cheaper and more secure forms of electricity generation, such as from natural gas, are available. CAENZ is of the view that the analysis has omitted some costs and trade-offs which could significantly alter the conclusions made by government:

- A high proportion of wind generation, as will be the case with the 90% renewables target, raises significant issues of system security which have not yet been adequately investigated and are not well understood. Additional back-up and stand-by generation facilities and other requirements such as frequency and voltage control have not been fully costed into any of the current assessments. Gas-fired generation is assumed to be a candidate to provide such stand-by but there is no business case to support the high capacity, low throughput supply of gas required for this purpose unless associated with substantial quantities of baseload gas supply.
- Transmission grid enhancements and new construction to enable intermittent renewables have not been included in the economic analysis undertaken by government nor have the tools been developed to determine these requirements. However, as most renewables in the expansion plans are located further from load centres than thermal plants, the cost of these enhancements is likely to be substantial. Without transmission enhancements being factored into the analysis, renewables generation costs must be regarded as overly optimistic compared to the thermal generation costs presented.
- The option of a high uptake of gas for electricity generation without significant coal use was not analysed. Early replacement of Huntly coal fired generation by gas fired combined cycle plants would give significant carbon emissions savings.
- The energy strategy does not examine in depth the likely impact the high renewables policy will have on the gas industry and implicitly assumes it will sustain itself to provide its intended back-up role. CAENZ's review suggests that the policy puts this role at risk.

The renewables policy has the potential to have a negative impact on broader primary energy supply. The focus of government energy strategy has been consumer energy, in particular electricity generation. Gas is not only a contributor to consumer energy but a significant and stable contributor to primary energy, despite being a relatively small industry in terms of participants and direct impact on consumers. A negative impact on gas reserve development by the 90% renewables policy will place stress on the gas industry through depleting reserves and increasing gas prices and will impact on the industrial, commercial and residential markets with consumers trending to electricity, coal or oil. Such a shift will result in increased carbon dioxide emissions and increases the risks to energy security of supply. As the purpose of the renewables policy is to reduce emissions, it is important that the policy and its attendant analysis take account of the full implications on primary energy supply rather than the narrow focus on electricity generation taken by government.

The renewables policy increases risks to energy security of supply and should not be legislated until a complete analysis of its impacts has been undertaken. CAENZ's review of the policy reveals a number of costs and risks to energy sector security and the gas industry in particular which have not been adequately scrutinised by the government. As the policy stands, it can lead to the suppression of the gas industry to the advantage of coal with its higher carbon emissions. It is important that legislation at least be deferred until such time a complete analysis of the full impacts of the policy has been undertaken and appropriate legislative settings made. The gas sector is a significant and proven contributor to New Zealand's economic base and its future is worthy of important public policy debate and should not be compromised by an aspirational 90% target for renewables technologies which are unproven on the scale envisaged in New Zealand.

APPENDICES

Appendix 1: Key Data Assumptions for Electricity Modelling

Discount rate: 7%
Shortfall costs:
First 5% of demand not met $500/MWh
Remainder of demand not met: $2000/MWh

HVDC capacity
Current capacity:
700 northward, 620 southward
From 1 Jan 2012:
1400 northward, 620 southward

Gas Price		
Year	High Gas $/GJ	Other Scenarios $/GJ
2007	5.5	5.5
2008	5.5	5.5
2009	6	6
2010	6.5	6.5
2011	6.5	6.5
2012	7	7
2013	7	7
2014	7	8
2015	7	8
2016	7	8
2017	7	9
2018	7	9
2019	7	9
2020	7	10

Other Fuel Prices	
Type	$/GJ
Coal	4
Dsl	25
Lig	1.8

CO_2 Costs		
	High Gas $/tonne	Other Scenarios $/tonne
2010	3.75	10
2011	4.5	12
2012	6.0	16
2013	7.5	20
2014	9.0	24
2015	10.5	28
2016	12.0	32
2017	13.5	36
2018	15.0	40

(constant after 2018)

CO_2 Emissions	
Fuel	kt CO2/PJ
Coal	91.2
Lignite	95.2
Gas	52.8
Diesel	73.0

Geothermal CO2 emissions:(Electricity Commission
100t/GWh generation
(Energy Outlook 2006 85t/GWh)

Fuel Costs, including Carbon Cost High Gas Scenario				
Year	Gas $/GJ	Coal $/GJ	Diesel $/GJ	Geotherm $/MWh
2007	5.5	4	25	0
2008	5.5	4	25	0
2009	6	4	25	0
2010	6.7	4.34	25.27	0.38
2011	6.74	4.41	25.33	0.45
2012	7.32	4.55	25.44	0.6
2013	7.4	4.68	25.55	0.75
2014	7.48	4.82	25.66	0.9
2015	7.55	4.96	25.77	1.05
2016	7.63	5.09	25.88	1.2
2017	7.71	5.23	25.99	1.35
2018	7.79	5.37	26.1	1.5
2019	7.79	5.37	26.1	1.5
2020	7.79	5.37	26.1	1.5

Fuel Costs, including Carbon Cost Other Scenarios (Excluding High Gas)				
Year	Gas $/GJ	Coal $/GJ	Diesel $/GJ	Geotherm $/MWh
2007	5.5	4	25	0
2008	5.5	4	25	0
2009	6	4	25	0
2010	7.03	4.91	25.73	1
2011	7.13	5.09	25.88	1.2
2012	7.84	5.46	26.17	1.6
2013	8.06	5.82	26.46	2
2014	9.27	6.19	26.75	2.4
2015	9.48	6.55	27.04	2.8
2016	9.69	6.92	27.34	3.2
2017	10.9	7.28	27.63	3.6
2018	11.11	7.65	27.92	4
2019	11.11	7.65	27.92	4
2020	12.11	7.65	27.92	4

(N.B. Fuel cost data obtained directly from Electricity Commission SDDP modelling database.)

Electricity Commission assumption of maximum gas consumption per year 75 PJ not included in CAE modeling

GXP Demand Plus AC Transmission Losses				
	GWh		Growth Rate	
	North	South	North	South
2007	25918	15008		
2008	26497	15236	2.23%	1.52%
2009	27183	15477	2.59%	1.58%
2010	27805	15666	2.29%	1.22%
2011	28355	15808	1.98%	0.91%
2012	28899	15938	1.92%	0.82%
2013	29459	16070	1.94%	0.83%
2014	30040	16205	1.97%	0.84%
2015	30628	16339	1.96%	0.83%
2016	31176	16459	1.79%	0.73%
2017	31717	16577	1.74%	0.72%
2018	32265	16697	1.73%	0.72%
2019	32819	16819	1.72%	0.73%
2020	33379	16942	1.71%	0.73%
2021	33891	17049	1.53%	0.63%
2022	34391	17151	1.48%	0.60%
2023	34895	17255	1.47%	0.61%
2024	35406	17361	1.46%	0.61%
2025	35920	17470	1.45%	0.63%
2026	36421	17578	1.39%	0.62%
2027	36919	17688	1.37%	0.63%
2028	37422	17799	1.36%	0.63%
2029	37929	17911	1.35%	0.63%
2030	38441	18025	1.35%	0.64%
2031	38967	18143	1.37%	0.65%
2032	39501	18263	1.37%	0.66%
2033	40041	18386	1.37%	0.67%
2034	40585	18508	1.36%	0.66%
2035	41135	18632	1.36%	0.67%
2036	41714	18765	1.41%	0.71%
2037	42307	18901	1.42%	0.72%
2038	42907	19039	1.42%	0.73%
2039	43511	19181	1.41%	0.75%
2040	44119	19325	1.40%	0.75%
2041	44736	19470	1.40%	0.75%
2042	45361	19616	1.40%	0.75%

Capital Costs ($/kW capacity installed)

Coal fired	2400
CCGT	1050
OCGT	820
Wind	2600
Geothermal	4500

Appendix 2: Changes to Electricity Commission Data Assumptions

Plant Availability assumed by EC for combined cycle plants is clearly far too high, and that for coal plants is also too high.

	Availability (%)	
	EC	CAE
Combined Cycle Plants	96	85
Existing Geothermals	75	90
New Plymouth	95	85
Whirinaki	90	95
P40	92	90
New coal	90	85

Electricity Commission Minimum Generation Constraints (MW)

	Summer	Winter
TCC	205	300
OTB	210	310
E3p	210	310
Huntly units	0	90
New Gas Plants	225	330
Rodney	130	190
TCC2	210	305

These constraints were removed for CAE modelling, but unit commitment constraints were used, i.e. if in service, large thermal plants are required to operate at some minimum level.

Electricity Commission assumption of maximum gas consumption per year of 75 PJ was not included.

Appendix 3: Model Description - Optimal Generation Dispatch Modelling

To calculate generation dispatch and consequent fuel consumption, carbon dioxide emissions, etc, and optimal generation dispatch model has been used. Dispatch of each plant can only be calculated by modelling it as part of the integrated system, so a complete model of the New Zealand generation system is necessary.

The Stochastic Dual Dynamic Programming model (SDDP) was selected as it is capable of representing most of the key aspects of the New Zealand system, for a long term study. Important features of the SDDP model include:

- accurate representation of the uncertain nature of hydro system inflows
- stochastic management policy for hydro storage lakes
- treatment of both hydro and thermal plants
- ability to handle retirements of existing plants, and commissioning of new plant
- sufficiently long time horizon (40 years)
- modelling of HVDC link
- representation of annual, seasonal and monthly patterns in load
- optimal dispatch, rather than rule based, to allow consistent treatment of a wide range of system conditions and system configurations.

The AC transmission system can also be modelled in detail, but this feature was not used for the current study due to data requirements.

SDDP is one of the most widely used models throughout the world for hydro-thermal power system planning. This software was developed and is maintained by Power Systems Research Inc, of Rio de Janeiro, Brazil. It is used extensively in Central and South America and has also been used in Eastern Europe, the Philippines, the US Pacific Northwest, and in New Zealand for several years. The model is designed both for medium term system operations planning and for longer-term system development studies. The time increment used for this study was one month, although weekly time steps can be used for more detailed studies.

The objective of the model is to meet a specified system load at least cost - no gaming by market participants is modelled. The prices determined by SDDP will generally represent a lower bound on market prices, and the probabilities of shortfall calculated by SDDP are also likely to be a lower bound on those realized in a market situation.

A true stochastic optimal dispatch is determined by SDDP. This means that at each stage the model uses only the information that would be available to a real decision maker - it does not have foresight regarding future inflows. Deterministic models, i.e. those with foresight, will show lower probabilities for shortfall as they will retain extra water in storage in anticipation of the future tight supply situation. Stochastic dynamic programming is commonly used methodology for hydro-thermal optimisation, but requires aggregation of hydro reservoirs, resulting in a loss of information due to the different inflow patterns to various reservoirs. A key feature of the SDDP algorithm is an iterative sampling strategy used to build up a function describing the value of water in storage. The sampling methodology involves calculating the function in most detail for those combinations of reservoir levels that are actually needed. Once the function has been calculated, a final simulation is carried out using the full set of historical inflow sequences so that results can be related to specific observed inflows from the hydrological record.

Appendix 4: Electricity Commission Generation Development Programs

Appendix 3: Electricity Commission Generation Development Programs

90% Renewables:

North Island Plant - Decommissioning		
Wairakei	163	2011
Huntly Coal Unit 1	225	2013
Huntly Coal Unit 2	225	2015
Wairakei Binary	14	2016
Huntly Coal Unit 3	225	2017
Huntly Coal Unit 4	225	2017
Huntly Gas	60	2017
New Plymouth Unit 1	100	2020
New Plymouth Unit 2	100	2020
New Plymouth Unit 3	100	2020
Taranaki CC	377	2023
Huntly Reserve Unit 1	245	2028
Huntly Reserve Unit 2	245	2028
Otahuhu B	365	2030
North Island New Hydro		
Otoi Waiau	17	2012
Mohaka	44	2017
Mangawhero to Wanganui Diversion	60	2018
Whakapapa Papamanuka	16	2020
Tarawera at Lake Outlet	14	2022
Wairehu Canal	11	2025
Waitangi Falls Ruakiteri	16	2027
Whangaehu	20	2027
Waihaha R West Taupo	10	2027
Kaituna Low Level	38	2028
Pumped Storage Hydro	300	2029
Pohangina River	10	2031
Tarawera at Te Matae Road	10	2031
Kaituna High Level	35	2042
Wairua Falls	11	2042
Rangitaiki at Mangamako	13	2042
North Island New Thermal		
Kawerau Geothermal	90	2009
Ngawha Geothermal 2	15	2009
Te Rere Hau Wind	49	2009
West Wind	143	2009
Rotokawa Expansion	90	2010
Te Waka Wind	102	2010
Titioku Wind	48	2010
TeMihi Geothermal	240	2011
Tukai Rd Wind	55	2013
Huntly Reserve 1	245	2013
Generic Geothermal 1	80	2014
Motorimu Wind	80	2014
Generic Geothermal 2	80	2015
Red Hill Wind	20	2015
Huntly Reserve 2	245	2015
Generic Geothermal 3	80	2016
Belmont Wind	80	2016
TeUku Wind	84	2016
Open Cycle GT 2	150	2017
Generic Geothermal 4	80	2018
LongGully Wind	70	2018

Turitea Wind	150	2019
Open Cycle GT 3	150	2020
Generic Geothermal 5	80	2020
Wind Central NI	100	2020
Wind Wararapa 1	100	2020
Puketiro Wind	120	2020
Marsden CoGen Refurbishment	85	2020
Pouto Wind	300	2021
Generic Geothermal 7	80	2022
Open Cycle GT 1	150	2023
Open Cycle GT 4	150	2023
Wind Wairarapa 2	100	2023
Generic Geothermal 8	80	2024
Rototuna Forest Wind	250	2024
Top Energy Wind	10	2024
Generic Geothermal 9	80	2026
Hawkes Bay Wind	225	2027
Open Cycle GT 5	150	2028
Generic Geothermal 10	80	2028
Glenbrook Expansion	80	2030
Generic Geothermal 11	40	2031
Wainui Hills Wind	30	2031
Carbon Capture and Sequestration Coal	400	2032
Open Cycle GT 6	150	2036
Carbon Capture and Sequestration Coal 4	400	2037
Otahuhu B New	410	2038
Generic Wind Auckland	40	2039
Generic Wind Waikato	100	2041
Generic Wind Taranaki	100	2041
Mokaira Wind	16	2041
Taharoa Wind	100	2042
Taumata Wind	44	2042
Biomass Cogen 1	30	2042
Taranaki Cogen	50	2042
South Island New Hydro		
Deep Stream	5	2008
Hawea Gates	16	2010
Kakapotahi River	17	2015
Toaroha River	25	2015
Wairau	70	2015
Pukaki Gates	44	2015
Waitaki North Bank	280	2017
Clutha Queensberry	180	2019
Clarence	70	2022
Dobson (Arnold)	50	2035
Arahura River	18	2042
South Island New Thermal		
Hayes 1 Wind	150	2011
Hayes 2 Wind	160	2013
LakeMahinerangi Wind	200	2023
Open Cycle GT	150	2040

Huntly Early Retirement

This scenario is developed from the Base Case Renewables scenario, with the following major changes:

Huntly Coal units 3 & 4 retire in 2017, instead of 2030

Huntly Coal units 1 & 2 moved to reserve status in 2017, decommission in 2029

Otahuhu C and Rodney 1 commissioned in 2017

Generic CCGT deleted 2030

Open Cycle GT 2 deleted 2031

Base Case Renewables

North Island Plant - Decommissioning		
Wairakei	163	2011
Wairakei Binary	14	2016
New Plymouth Unit 1	100	2020
New Plymouth Unit 2	100	2020
New Plymouth Unit 3	100	2020
Huntly Coal Unit 1	225	2030
Huntly Coal Unit 2	225	2030
Huntly Coal Unit 3	225	2030
Huntly Coal Unit 4	225	2030
Huntly Gas	60	2030
Taranaki CC	377	2033
Otahuhu B	365	2038
North Island – New Hydros		
Otoi Wai	17	2012
Mohaka	44	2016
Mangawhero to Wanganui Diversion	60	2024
Pumped Storage Hydro	300	2025
Tarawera at Lake Outlet	14	2029
Whakapapa Papamanuka	16	2031
Wairehu Canal	11	2034
Waitangi Falls Ruakiteri	16	2034
Kaituna High Level	35	2037
Kaituna Low Level	38	2037
Whangaehu	20	2038
Pohangina	10	2042
Tarawera at Te Matae Road	10	2042
Wairua Falls	11	2042
North Island Other New Plant		
Kawerau Geothermal	90	2009
Ngawha Geothermal 2	15	2009
Te Waka Wind	102	2009
Te Rere Hau Wind	49	2009
West Wind	143	2009
Rotokawa Expansion	90	2010
TeMihi Geothermal	240	2011
Generic Geothermal 1	80	2014
Generic Geothermal 2	80	2015
Generic Geothermal 3	80	2016

Tauhara Geothermal	90	2017
Long Gully Wind	70	2017
Generic Geothermal 4	80	2018
Pouto wind	300	2018
Generic Geothermal 6	80	2022
Generic Geothermal 7	80	2023
Generic Geothermal 8	80	2024
Open Cycle GT 5	150	2028
Generic Wind Taranaki	100	2028
Generic Geothermal 9	80	2029
Generic Geothermal 10	80	2029
Wind Wararapa 1	100	2029
Motorimu Wind	80	2029
Puketiro Wind	120	2029
Taumata Wind	44	2029
Turitea Wind	150	2029
Glenbrook Expansion	80	2030
Generic Gas CC 1	410	2030
Generic Gas CC 2	410	2030
Open Cycle GT 2	150	2031
Generic Geothermal 11	40	2031
Top Energy Wind	10	2031
Wind Wairarapa 2	100	2032
Mokaira Wind	16	2032
Red Hill Wind	20	2032
Rototun	250	2033
Taranaki CC (New)	410	2033
Belmont Wind	80	2034
Hawkes Bay Wind	225	2035
Wainui Hills Wind	30	2035
Generic Wind Waikato	100	2037
Generic Wind Central NI	100	2037
Marsden Refurbishment	85	2038
Otahuhu B CC (New)	410	2038
Open Cycle GT4	150	2039
Generic Wind Auckland	40	2040
Taharoa Wind	100	2040
TeUku	84	2040
Open Cycle GT 6	150	2041
Generic Wave 1	50	2041
Generic Wave 2	50	2042
Generic Wave 3	50	2042
Biofuel Cogen 1	30	2042
Biofuel Cogen 3	30	2042
South Island – New Hydro		
Deep Stream	5	2008
Hawea Control Gates	16	2010
Pukaki Control Gates	44	2016
Toaroha River	25	2017
Te Anau Gates	40	2019
North Bank Tunnel	280	2020
Wairau	70	2022
Kakapotahi	17	2023
Lower Clutha River	35	2028
Clarence	70	2029
Dobson (Arnold)	50	2029
Taipo	33	2035
South Island – Other New Plant		

Project Hayes Wind, Stage 1	150	2011
Tiwai Point Wind	80	2023
West Coast Coal Seam Gas	30	2031
Kaiwera Downs Wind	160	2036
Generic Wind Otago	100	2038
Lake Mahinerangi Wind	200	2039
Project Hayes Wind, Stage 2	160	2041

High Gas

North Island Plant - Decommissioning		
Wairakei	163	2011
Wairakei Binary	14	2016
New Plymouth Unit 1	100	2020
New Plymouth Unit 2	100	2020
New Plymouth Unit 3	100	2020
Huntly Coal Unit 1	225	2030
Huntly Coal Unit 2	225	2030
Huntly Coal Unit 3	225	2030
Huntly Coal Unit 4	225	2030
Huntly Gas	60	2030
Taranaki CC	377	2033
Otahuhu B	365	2038
North Island – New Hydros		
Otoi Waiau	17	2012
Mohaka	44	2028
Mangawhero	60	2034
Tarawera Lake Outlet	14	2042
Kaituna Low Level	38	2042
North Island Other New Plant		
Tararua Windd 3	93	2007
Mokai Geothermal 3	17	2008
Kawerau Geothermal	90	2009
Ngawha Geothermal 2	15	2009
West Wind	143	2009
Open Cycle GT North 1	150	2010
TeMihi Geothermal	240	2011
Otahuhu C	407	2011
Generic Geothermal 1	80	2014
Generic Geothermal 2	80	2019
Generic Gas 2T	410	2023
Generic Geothermal 3	80	2024
Tauhara	90	2028
Generic Geothermal 4	80	2029
Generic Coal 4T	300	2029
Glenbrook Expansion	80	2030
Taranaki CC 2	380	2030
Marsden Coal	320	2030
Open Cycle GT North 3	150	2031
Mokaira	16	2032
Wainui Hills Wind	30	2032
Open Cycle GT North 2	150	2033
Taranaki CC new	410	2033
Gen. Wind Wairarapa 1	100	2034
Generic Wind Auckland	40	2035
Motorimu Wind	80	2035