Kicking the Fossil Fuel Habit: New Zealand’s 90% Renewable Target for Electricity

Geoffrey Bertram
School of Economics and Finance
Victoria University of Wellington

Doug Clover
School of Geography Environment and Earth Sciences
Victoria University of Wellington

The New Zealand Government has set its sights on 90% renewable electricity by 2025, mainly via the expansion of large-scale centrally-dispatched geothermal and wind generation. The country’s resource endowments make this transition feasible at low incremental cost relative to a business-as-usual trajectory, although the foreclosure of small-scale demand-side and distributed-generation options by New Zealand’s present electricity market design means that the new policy will mainly benefit the large incumbent generators. Barriers to small-scale entry may not be sustainable indefinitely, and a renaissance of decentralized energy solutions could potentially strand some of the new large-scale renewable projects as well as some legacy thermal capacity.

1. Background: NZ energy policy and its context

In October 2007 the New Zealand Government declared that 90% of the country’s electricity should be generated from renewable resources by 20251. The policy measures announced to achieve this goal, and passed into law by Parliament in September 20082, were the imposition of a carbon tax3 on electricity generation provisionally beginning in 2010, and a 10-year restriction on construction of new baseload fossil-fuelled electricity generation capacity “except where an exemption is appropriate (for example, to ensure security of supply)”4.

3 Although described as an “emissions trading scheme” the New Zealand scheme is in fact a tax, although the tax rate is to be determined by arbitrage with the world carbon market. See Bertram and Terry (2008) Chapter 4.
This chapter explores whether and how the renewables target may be met, and evaluates the new policy framework associated with “renewables preference”. Section 2 sets out the record of New Zealand’s 1970-2000 shift away from its historically high renewables share; section 3 reviews some common issues with integrating renewables into an electricity system; section 4 reflects on the achievement of 100% renewable electricity supply in Iceland and compares it with New Zealand; and section 5 reviews the New Zealand Government’s modeling work on the future evolution of the generation portfolio in New Zealand and considers some implications of the supply-side bias built into New Zealand’s electricity market design.

Renewable portfolio standards are familiar from many other jurisdictions, but a 90% target is unusually high (cf Musier and Adib, this volume) and the structure of the New Zealand (NZ) electricity market presents some problems for its implementation. Generation is not regulated, and two of the five large generator-retailers are privately owned and consequently not subject to direction by Government as owner.

The new regulatory approach will require any new investment in thermal plant to secure an explicit “exemption” from the Minister of Energy and to carry the burden of an emissions tax on its operating costs. Neither of these measures provides certainty that the renewables target will be met. Future Ministers will have political discretion at any time to invoke one of the numerous loopholes built into the proposed legislation\(^\text{5}\) and allow a raft of new non-renewable generation to be built. Neither the emissions tax nor the requirement for new thermal plant to gain “exemption” enjoy bipartisan political support, which means that neither is entrenched for the coming decade.

Although the policy regime appears fragile, there are market forces at work that will tend to push NZ towards a higher renewables share of generation.

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\(^{5}\) Climate Change (Emissions Trading and Renewable Preference) Bill clause 67, new Electricity Act section 62C exempts all existing generation plant and allows new plant to be exempted by regulatory declaration. New section 62G allows exemptions to be granted for baseload plant that mitigates emergencies, provides reserve energy, supplies isolated communities, functions as a cogeneration facility, uses a mix of renewable and fossil fuels or waste and fossil fuels, or replaces existing plant with a more emission-efficient process.
Technological progress is cutting the costs of wind, wave and solar technologies, while fossil-fuel prices for electricity generators in New Zealand are at last rising after being suppressed for nearly four decades by access to cheap natural gas.

New Zealand is well endowed with resources to sustain increased renewables-based generation. Over the next three decades the New Zealand Electricity Commission’s central demand projection calls for up to 8,000 MW of additional capacity and the Commission’s database identifies around 6,500 MW of feasible large-scale (over 10MW) renewables-based options with long-run marginal cost below NZ$130/MWh. The country’s potential large-scale wind resource alone (including higher-cost opportunities) is assessed at over 16,000 MW.

To this has to be added small scale distributed wind and solar generation and demand-side response, which have been held back by institutional barriers rather than lack of resources. The oligopolistic structure of the electricity market has effectively foreclosed entry at that level, and pro-competitive regulatory measures such as feed-in tariffs, net metering, or mandatory wheeling of third-party power on local networks, are yet to be introduced even two decades after market restructuring began. Over time these obstacles to technological progress and competitive entry are likely to erode, opening the way for a transformation of both supply and demand sides of the electricity sector which could render fossil fuels redundant apart from a residual role as system backup and an irreducible tranche of industrial cogeneration.

As relative prices and technological progress have swung the market balance in favour of renewables, the dominant New Zealand generators have been racing to secure strategic footholds on key renewable resources by constructing large windfarms and geothermal plants, while a new-entrant entrepreneur is experimenting with very-large-scale sub-sea tidal generation. As the next section describes, this represents the reversal of a half-century-old trend in the other direction.

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6 See Table 3 later in this chapter.
2. Historical Development of the New Zealand Portfolio

2.1 The Rise and (Relative) Fall of Hydro

Electricity reached New Zealand in the 1880s when the country was still in its pioneering phase (Martin 1991). By the time of the First World War the country had a patchwork of local stand-alone supply systems and associated distribution networks, each with its own voltage and frequency standards. Starting in the 1920s an integrated supply network was established in each of the two main islands under Government auspices, including the construction of large state-owned hydroelectric stations which dominated supply by the mid-1960s.

Because of its mountainous topography, New Zealand was initially well endowed with opportunities to construct large-scale hydro. By the 1940s the share of fossil fuels in total capacity had fallen below 10% (Figure 2), with small oil-fired plant providing local peaking capacity and about 50MW of coal-fired plant in Auckland and Wellington providing backup supply. Through the 1950s demand grew ahead of the pace of hydro construction and the gap was filled by investment in new coal and geothermal plant (Figure 1), but the pace of new hydro construction accelerated in the 1960s as a cable connecting the North and South Islands made possible the development of large hydro resources in the far south to supply the northern market.

As Figure 1 shows, the pace of hydro and geothermal construction slowed in the 1970s while that of fossil-fired thermal generation increased sharply. Over the two decades from 1965 to 1985 the fossil-fuel share of capacity rose from 11% to 33%. In 2004 it was still 32%.8

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8 As Bertram (2007) pp.224-225 notes, the introduction of “commercial” incentives and behaviour under the reforms of 1987-1992 led quickly to the decommissioning of reserve thermal capacity, which was costly to maintain but held prices down during the dry winter of 1992, thereby reducing generation profits. The demolition of this 620MW of privately-unprofitable plant temporarily cut the fossil-fuel share of capacity to 25% in the mid-1990s, while sharply reducing the system’s security margin and increasing the economy’s exposure to blackouts in dry years.
Figure 1: New Zealand Electricity Installed Capacity and Generation by Fuel Type, 1945-2006

Figure 2: Generation by fuel type

1945-49
2,472 GWh
Coal 4% Oil 2%
Hydro 95%

1975-79
21,436 GWh
Oil 3% Gas 11%
Coal 4% Biomass 2%
Geothermal 6%
Hydro 75%

2005-07
42,013 GWh
Gas 23%
Oil 0%
Coal 11%
Biomass 2%
Wind 2%
Geothermal 8%
Hydro 55%
2.2 Cheap gas, relative costs, and the rise of non-renewables

New Zealand’s transition from 90% renewable electricity in the early 1970s to 65% by 2006 in terms of generation output (Figure 1) was a direct result of relative-cost trends. The availability of cheap natural gas from the giant offshore Maui field\(^9\), and the rising cost of large hydro construction as development of the most accessible and suitable river systems was completed and diminishing returns to hydro set in, produced a relative-price swing directly contrary to the international effect of the first two oil shocks.

New Zealand’s Maui gasfield was developed under a long-term take-or-pay contract signed in 1973 with the Government as buyer, at a delivered-gas price that was only incompletely inflation-indexed. As a result, the real fuel cost of state-owned thermal generation fell steadily through the 1970s and 1980s (Figure 3). A fully-indexed purchase and sale agreement between the Crown and ECNZ\(^{10}\) was negotiated in 1989 but the fuel cost per kWh of generation continued to fall during the 1990s due to the greater efficiency of new baseload thermal capacity and the scrapping of reserve thermal plant.

The oil shocks of 1973 and 1980 would probably have forced a reorientation back to renewables (especially geothermal) had not the fortuitous coincidence of major natural gas discoveries over the previous decade, with no means of exporting the gas, delinked thermal generation costs from world oil prices.

\textbf{Figure 3: Real Fuel Cost of Fossil-fired Generation in New Zealand Compared with World Oil Price Trends}


\(^{10}\) Electricity Corporation of New Zealand, the corporatised successor to NZED.
Figure 3 shows a sharp increase in fuel cost in the two years after the first oil shock in 1973 when existing thermal capacity was coal or oil fired; but over the following decade natural gas completely displaced oil and largely displaced coal. The baseload oil-fired plant at Marsden, which had accounted for over 6% of total...
supply in 1974, had been downgraded to dry-year reserve status by 1980\textsuperscript{11}. Figure 4 shows the rapid post-1973 elimination of oil (and to a considerable extent coal also) from thermal electricity generation, a trend eventually reversed by a revival of coal use only from 2003 on as Maui output fell and the gas price rose\textsuperscript{12}.

**Figure 4: New Zealand’s Switch to Gas in Thermal Generation**

The switch to cheap gas, and consequent rising reliance on fossil fuel, seen in Figures 1 - 4, cannot be repeated today in the face of the rising oil price since 2003, because no new gasfield of the scale of Maui has been found, and because the emergence of a global LNG market means that the domestic price of gas has become linked once again to the oil price\textsuperscript{13}. In the coming two decades, the cost of gas for New Zealand generators will move with (and to) the world oil price,

\textsuperscript{11} The second major oil-fired plant at Marsden was completed in 1978 but never commissioned.

\textsuperscript{12} New Zealand’s coal reserves are large, and the life-time cost of electricity from coal plant remains competitive in the absence of a carbon tax. However the combination of the planned emissions trading scheme and ten-year moratorium on new baseload thermal plant will keep coal at the margin of the future electricity generation portfolio.

\textsuperscript{13} New Zealand does not yet have any LNG terminal, but the world LNG price is already used by the industry and the Government as a pricing benchmark.
placing a squeeze on the profitability of thermal generation relative to renewables. This squeeze will be exacerbated by the forthcoming emissions-trading regime, which will impose a carbon tax on thermal generation starting in 2010.

The change in relative profitability of renewables relative to non-renewables since 2000 has been rapidly reflected in a surge of new investment in wind and geothermal capacity. By October 2007, when the Government announced its new strategy of aiming for 90% renewables and restraining construction of new thermal plant, market forces were already moving strongly in that direction. Electricity sector modelers in the New Zealand Electricity Commission and Ministry of Economic Development estimated in late 2007 that a carbon tax of NZ$50/tonne\textsuperscript{14} CO\textsubscript{2}-equivalent should suffice to make a 90% renewables share fully economic by 2030\textsuperscript{15}.

3. Integrating Renewables into the Generation Portfolio in the future

With oil and gas prices trending upward and carbon taxes in prospect, the only reasons for having any fossil fuel in the generation mix (apart from cogeneration, where electricity is a joint product) are operational matters such as dry-year backup for hydro and, in some scenarios, a need for reliable peaking plant to offset the intermittency of some renewable generation technologies. This section reviews the intermittency problem and other issues with the integration of renewables.

3.1 Intermittent Renewables and Reliable Non-renewables

Primary energy sources are generally classified as renewable or non-renewable on the basis of whether they draw on a depleting energy resource. Fossil fuel is non-renewable, while hydro, wind, solar and wave power are generally treated as

\[\text{14} \quad \text{Roughly US$30.}\]
\[\text{15} \quad \text{Samuelson, R. et al 2007, Supplementary Data Files, “Emission Pricing on all Sectors” Figure 6b.}\]
renewable. On the borderline are nuclear\textsuperscript{16}, which depletes its fuel stock but at a relatively slow rate, and geothermal energy (Williamson, this volume), which in most cases draws on an underground reservoir of heat sufficiently large to enable depletion to be ignored within the usual planning horizons for energy supply\textsuperscript{17}. Geothermal is treated as renewable, and its carbon emissions are low (though not zero).

An important difference between renewables and non-renewables is that the latter provide greater flexibility and controllability in the rate and timing of generation. A well-designed portfolio of fossil-fuel generating plant can be operated to follow load with few constraints. Renewables-based generation, in contrast, is dependent upon natural processes to supply the primary energy, which means that electricity systems with very high percentages of renewable generation must be designed with an eye to constraints that are outside the control of the system operator: wind and wave fluctuations, rainfall, the daily cycle of solar radiation, the regular but time-varying movement of tides. This intermittency must of offset in some way - by storage technologies that enable generation and consumption of electricity to be separated in real time; or from non-renewable generators able to ramp up and down to fill gaps in renewable supply; or by a demand side that is able to respond in real time to price signals reflecting fluctuations in supply.

The operational difference between a fully-renewables system and a fully non-renewable one thus lies not in the baseload part of the spectrum but in the nature and extent of output variability in non-baseload plant (Figure 5).

\textbf{Figure 5: Schematic Comparison of Renewable and Non-renewable Technologies}

<table>
<thead>
<tr>
<th>NON-RENEWABLES</th>
<th>RENEWABLES</th>
</tr>
</thead>
<tbody>
<tr>
<td>Diesel and gas-turbine peaking plant</td>
<td>Increasing variability</td>
</tr>
<tr>
<td>Baseload coal, oil and gas plant</td>
<td>Nuclear</td>
</tr>
<tr>
<td>Nuclear</td>
<td>Geothermal</td>
</tr>
<tr>
<td>Biofuels and baseload-capable hydro</td>
<td>Predictable intermittent: tidal, solar</td>
</tr>
<tr>
<td>Run-of-river hydro, wind, wavepower</td>
<td>Increasing intermittency</td>
</tr>
</tbody>
</table>

\textsuperscript{16} Nuclear power is ruled out for New Zealand by a long-standing bipartisan political consensus.

\textsuperscript{17} Note, however, the case of the geothermal project developed in New Zealand at Ohaaki, where a 104 MW plant was commissioned in 1989 but had been derated to 40MW by 2005 due to unexpected depletion of the resource, accelerated by the cooling effect from reinjection of cooled fluids directly into the reservoir. See \url{http://www.nzgeothermal.org.nz/geothermal_energy/electricity_generation.asp}.
In a non-renewables generation portfolio, the system operator is able to raise and lower capacity utilisation in peaking plant in response to fluctuations in demand, which means that the adequacy and reliability of supply are straightforwardly attributable to human decisions on construction, maintenance, fuel procurement and system dispatch. The “increasing variability” on the left side of Figure 5 is therefore a matter of deliberate load-following, and a positive feature of the generation portfolio.

In a renewables portfolio, “increasing intermittency” implies output variations that are driven by natural processes rather than demand fluctuations. This naturally-occurring intermittency is largely uncorrelated with demand peaks. Fluctuations may be short-run as with wind and wave, or over longer time periods as occurs with dry versus wet years in New Zealand hydro generation, but in either case the system operator needs to have some controllable component of the overall system that can be scheduled to keep supply and demand continuously in balance. These issues are discussed in relation to wind power by Wiser and Hand (this volume) and are the subject of ongoing research by the New Zealand Electricity Commission (Electricity Commission 2007a, 2007b, 2008a). There is no physical feasibility limit to integrating wind into the New Zealand system up to around 50% of total generation, but there are likely to be rising costs of ancillary services which would be reflected in wholesale prices (Ancell 2007 section 7).

In most electricity systems wind generation is treated as a non-dispatchable source of variation in the residual demand faced by central generators. In contrast New Zealand’s large new wind farms are included in the system operator’s central dispatch schedule, on the basis of a two-hour-ahead “persistence forecast” of their output and at a constrained must-run offer price of zero or NZ$0.01/MWh (Ancell 2007; Electricity Governance Rule 3.6.3318). Dispatch is possible because virtually all the wind farms are owned by large generator-retailers with sufficiently diversified in-house generation portfolios to allow intra-firm backup, usually from hydro; and because of the relatively high load factors of wind in

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New Zealand, generally 30-45%. The virtual absence of distributed wind
generation, injecting power downstream of exit points from the grid, means that
variability of residual load on the grid due to distributed wind has not yet been an
issue in New Zealand.

In New Zealand, hydro generation has historically provided controllable
variability. Hydro is a high-quality renewable, combining baseload and peaking
capability, although it faces limitations imposed by New Zealand’s rivers which
allow only limited storage and which are subject to minimum and maximum flow
requirements for environmental reasons. Development of hydro resources in New
Zealand has, however, reached a mature stage, with few major rivers remaining
undammed and rising costs of developing them for electricity – both construction
costs, and the rising opportunity value of wild and scenic rivers to the country’s
tourism industry, which is now the leading earner of foreign exchange.

The planned return to 90% renewables will therefore have to rely mainly on
geothermal development combined with wind power and wave and tidal
generation. To offset the intermittency of these last three technologies, a
traditional solution would be to construct gas-fired or oil-fired peaking plant to
cover for periods when demand is high and wind and wave are offline. With such
new fossil-fired capacity in the system and bidding for dispatch, the market would
be apt to “choose” a significant amount of electricity supply from these fossil-
fired stations, which would rule out a 100% renewables system, and make even
90% problematic.

The problem of intermittency is obviously far less in an electricity system that is
interconnected with other countries. The UK has backup from the EU. Individual
US states such as California are usually interconnected with others. In such cases,
a target for the proportion of renewables in domestic generation may be met even
when a substantial proportion of demand is served from externally-located non-
renewables.

New Zealand is an island system without interconnection to any other country
although the two main islands are interconnected and provide mutual support.
Integrating intermittent renewables is in principle more challenging for island
systems than for continental ones because of the lack of external backup. When the islanded market is small it also suffers from inability to reap economies of scope and scale in maintaining reliability standards.

Much depends, of course, on precisely which mix of renewables is actually installed. Diversification helps: a range of technologies spread over a range of locations can smooth out the consequences of intermittency at the level of the single generating unit. Having windfarms dispersed across a wide geographical area should result in a more reliable flow of generation because wind speeds vary from place to place and fluctuations in wind speed are less likely to be correlated across widely-dispersed sites. Intermittency patterns of wind, waves, tides and rainfall can offset one another so that the probability of securing a reliable, hence easily dispatchable, flow of electricity rises as the number of interlinked technologies increases (Grubb 1991).

3.2 A Model of the Trade-Off

Conceptually the intermittency problem can be captured by a diagram such as Figure 6. Here iso-reliability contours (indexed with 100% reliability as the initial target) are drawn sloping up on the assumption that as the share of renewables in the generation portfolio rises (horizontal axis), the cost of procuring the necessary capacity reserves to maintain any target level of reliability (vertical axis) rises at the margin (as is the case for, e.g., wind penetration in the EU; see Auer et al 2007 pp.6-7). At point A, to meet a 90% renewables target with 100% of target reliability, the cost $C_{90}$ must be incurred, whereas the system with zero renewables is shown as having a full-reliability cost of $C_0$. The difference between these two represents the cost of moving towards more renewables without sacrificing quality of supply. Holding the electricity price at $C_0$ while pushing the renewables share up to 90% in this case would reduce reliability to R=90 (point B).
A hypothetical feasibility constraint is included in Figure 6 to take account of the possibility that, for a particular country, its resource endowment or particular characteristics of its electricity load may place some ceiling on the ability of the system to “buy” reliability as renewables increase their share. The position and slope of the constraint would be determined by both resource endowments and the state of technology. If it exists, then the menu faced by policymakers seeking to maximise renewables subject to cost and feasibility constraints would be the set of corner solutions between the reliability contours and the feasibility constraint, including in this case point A.

The position and slope of the contours in Figure 6 depend on the nature, diversity, and geographical dispersion of a country’s renewable resources. An important modelling issue in the New Zealand case is the slope of these contours, which will dictate the long-run costs of moving to a high-renewables system relative to a status-quo one.
The intermittency problem can be reduced greatly by technological progress in the design of wind and wave farms to render them more controllable and able to contribute directly to maintenance of frequency and voltage on the overall grid, and by installing substantial excess renewables capacity in diversified locations (Grubb et al 2006).

There are two renewable technologies which are not subject to intermittency: geothermal (Williamson, this volume) and hydro with multi-year storage capacity. These are the key to the ability of Norway and Iceland to operate fully renewables-based generation portfolios, as discussed in the next section.

4. Norway and Iceland as Models

Within the OECD there are two very-high-renewables electricity systems: Norway (99% renewables) and Iceland (100%). New Zealand ranks third behind these (so long as nuclear is classified as non-renewable); see Figure 7.

**Figure 7: Electricity Generation by Primary Energy Source, OECD Countries**

Norway is not comparable with New Zealand since its hydro has massive storage capacity (unlike New Zealand’s) and is backed up by neighbouring Sweden’s large nuclear capacity which gives Norway almost complete security of supply.

Iceland, however, is an island system like New Zealand, which is 100% renewable in terms of generation on the main island. Iceland confronts no operational problems with integration of renewables, because its portfolio is dominated by two perfectly-matched renewable technologies: hydro and geothermal. Geothermal provides reliable baseload and is fully dispatchable, while hydro provides peaking capacity and is also dispatchable. In 2006 Iceland had five major geothermal plants producing 26% of total electricity consumption, while 0.1% came from fossil fuels and the remaining 73.4% was from hydro.

Like New Zealand, Iceland embarked on large hydro construction in the 1920s, and has ever since had a system based primarily on hydro, but in the 1960s and 1970s roughly 100MW of oil-fired plant was built, bringing the total thermal capacity up to 125 MW. The oil shocks of the 1970s, however, triggered a dramatic expansion of renewable capacity as part of a policy of reducing dependence on oil and coal (Grimmsson 2007). Between 1975 and 1985 installed hydro capacity doubled from 389MW to 752MW while geothermal capacity increased fifteen-fold from 2.1MW to 41.2MW. After 1981 Iceland’s fossil-fuel plant never supplied more than 9GWh per year (around 0.1% of total supply), mainly to areas not connected to the grid on the main island. Geothermal now accounts for 25% of total installed capacity of 1,698MW, and hydro for another 68%. (The remaining 7% appears to be mainly residual thermal capacity which provides a backstop for the system’s reliability of supply and peaking ability, but is hardly ever required.)

Table 1 gives comparative data for Iceland and New Zealand. Although less than one-tenth the population of New Zealand, Iceland has per-capita electricity generation more than three times as great. Both have over 60% of capacity

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19 The offshore island of Grimsey has a diesel-powered generator.
accounted for by hydro, but Iceland’s greater storage enables it to convert this to 73% of total supply whereas New Zealand’s hydro accounts for only 55% of supply.

Table 1 New Zealand and Iceland Compared

<table>
<thead>
<tr>
<th></th>
<th>Iceland</th>
<th>New Zealand</th>
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<tbody>
<tr>
<td>Population, 000</td>
<td>204</td>
<td>304</td>
</tr>
<tr>
<td>Population per capita, MWh</td>
<td>7.2</td>
<td>32.6</td>
</tr>
<tr>
<td>Electricity generated, GWh</td>
<td>1,460.40</td>
<td>9,925</td>
</tr>
<tr>
<td>of which hydro</td>
<td>1,412.90</td>
<td>7,289</td>
</tr>
<tr>
<td>geothermal</td>
<td>12.1</td>
<td>26.5</td>
</tr>
<tr>
<td>wind</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>fossil-fired</td>
<td>35.4</td>
<td>4.6</td>
</tr>
<tr>
<td>fossil-fired</td>
<td>334.1</td>
<td>1,698</td>
</tr>
<tr>
<td>of which hydro</td>
<td>243.8</td>
<td>1,163</td>
</tr>
<tr>
<td>geothermal</td>
<td>2.6</td>
<td>4.3</td>
</tr>
<tr>
<td>wind</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>fossil-fired</td>
<td>87.7</td>
<td>112.9</td>
</tr>
</tbody>
</table>


The two obvious contrasts between the two countries are their different reactions to the 1970s oil shocks, and the extent to which they have developed their geothermal resources. Looking at the historical evolution of the New Zealand generation portfolio (Figure 1 above), geothermal development stalled after the 1950s, despite the existence of a large-scale resource, and its share of total supply fell from around 12% in the mid 1960s to only 4% by 1990; see Figure 8. Although New Zealand pioneered geothermal generation in the 1950s, the technology fell back to below 5% of capacity from the 1970s on. In Iceland, where the first geothermal plant appeared only in the 1970s, geothermal rose rapidly to a quarter of total generation capacity by 2006.

Figure 8: Geothermal shares of capacity and generation, New Zealand and
Iceland

Share of total generation capacity

Share of total electricity generated

Sources: Iceland from Statistics Iceland website http://www.statice.is/Statistics/Manufacturing-and-energy/Energy
New Zealand from Ministry of Economic Development Energy Data File.
Confronted with the oil shocks of the 1970s, both countries de-linked their electricity supply systems from world oil prices, but they did so by very different means. Iceland, whose thermal generation relied entirely upon imported oil, delinked by construction of enough new hydro and geothermal capacity to eliminate fossil fuels entirely from the generation mix by 1983. New Zealand, as outlined above, delinked by switching to locally-produced natural gas via a large-scale thermal generation construction programme which raised the non-renewables share of generation to about one-third by 2006 (Figure 9).

**Figure 9: Non-renewables share of installed capacity**

Iceland’s strategy of delinking from oil prices by eliminating fossil fuels entirely from its electricity sector means it now has a permanent buffer against volatile oil markets, whereas New Zealand’s strategy of a switch to cheap gas was effective only so long as the Maui Contract dictated the local gas price. New Zealand is in the process of embarking on the Icelandic path, forty years later.
5. Modeling the Future NZ Portfolio

Whether moving to 90% renewables is feasible at acceptable cost is an issue best addressed by systematic modeling. This section reviews recent work on the future evolution of electricity generation in New Zealand under a variety of assumptions about policies and prices.

Since 2000 the Ministry of Economic Development has conducted several rounds of scenario work using its SADEM model (MED 2003, 2006, 2007); the Parliamentary Commissioner for the Environment has produced a scenario study focusing on renewables, distributed generation and demand side response (Potter et al 2005; Webb and Clover 2005); and Greenpeace has carried out a less formal study (Freeman et al 2007) as part of a worldwide modeling exercise (Ballesteros et al 2007). The leader in the field at present, however, is the Electricity Commission, the new sector regulator set up in 2003 (Bertram 2007 p.232).

5.1 The Electricity Commission’s GEM model

The Electricity Commission has developed a Generation Expansion Model (GEM) to simulate alternative scenarios for the generation portfolio and select the most cost-effective (Bishop 2007, Bishop and Bull 2007). GEM determines the optimal commissioning dates of new generation plant and transmission equipment in response to an exogenously-imposed forecast of demand for electricity. The GEM also simulates the optimal dispatch of both existing and new plant

The model’s objective function is to build and/or dispatch plants in a manner that minimises total system costs while satisfying a number of constraints. The main constraints are to:22

- satisfy a fixed load in each load block of each time period within each year
- satisfy peak load security constraints
- satisfy the specified reserves cover

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22 This list is from the Electricity Commission’s programmers notes within the main GAMs batch file.
account for both capital costs incurred when building new plants, and fixed and variable operating costs of built plant, including any specified carbon charge on the use of co2-emitting fuels

- satisfy energy constraints arising from the limited availability of hydro inflows
- satisfy HVDC constraints

Figure 10: Schematic Representation of the Electricity Commission’s Modeling

The main input to the model is a database of possible new generation options, their associated capital and fuel costs, plant performance, depreciation, and load factors, based on Parsons Brinckerhoff Associates (2006) and subsequent updates. The model also requires estimates of future hydro flows, the cost of carbon, and forecast loads during the different load blocks. These technical supply-side

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23 HVDC refers to the high voltage direct current link between the two main islands of New Zealand.

24 The load blocks used by the Commission are:

- b0n A no-wind peak spike
- b0w A windy peak spike
- b1n A peaky no-wind block
- b1w A peaky windy block
- b2n A shoulder no-wind block
- b2w A shoulder windy block
- b3 A mid-order block
data appear in the lower left part of Figure 10 as inputs to the least-cost generation scenarios.

The other key input if the demand forecast, which is based on modelling of three sectors: residential, commercial and industrial, and “heavy industry” (the Tiwai Point aluminium smelter). Forecasts are done at both national and regional levels (Kirtlan 2008).

The national-level modelling of residential and commercial/industrial demand uses regression analysis, with GDP/capita, number of households, and electricity price as the explanatory variables. The commercial and industrial model has only two variables: GDP and “Shortage”. Demand from heavy industry is assumed to be constant, unless the GEM scenario involves closure of the large aluminium smelter at Tiwai Point (17% of national load). The forecasts currently assume that future rates of improvement in energy efficiency are the same as historical rates, with no feedback to the “DSM” input box in Figure 10.

Regional-level load forecasts cannot be undertaken with econometric methods due to lack of historical data. Therefore, the model’s regional forecasts are based on an allocation of national demand, using regional population forecasts for residential demand and regional GDP growth for commercial and industrial.

The forecasts are subjected to Monte Carlo analysis to provide an estimate of the forecast error, and before the figures are incorporated into the GEM they are passed through the Commission’s hydrothermal dispatch model to estimate electricity demand per year, month and island and to divide the load into blocks.26

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25 The shortage variable is a dummy that removes from the regression results years in which “shortages” have occurred. This is done to ensure that demand is not biased downwards due to extraordinary circumstances; see Electricity Commission (2004).
26 The EC uses PSR Inc’s SDDP software package for this task (http://www.psr-inc.com.br/sddp.asp). The package is designed to calculate the least-cost stochastic operating policy of a hydrothermal system taking into account the following aspects:

- operational details of hydro plants
- detailed thermal plant modelling
- representation of spot markets and supply contracts;
With demand and generation opportunities thus exogenously determined, the GEM uses programming techniques to design a least-cost generation portfolio to meet that demand. The model does not incorporate risk-return tradeoffs of the sort pioneered by Awerbuch (2004) and Awerbuch and Berger (2003), and it does not include in its output a future wholesale price path for each scenario, although such a path is implicit. Although the GEM does not calculate wholesale electricity prices, the Commission does use the model outputs to estimate the price levels necessary to achieve life-cycle revenue adequacy for the marginal generator(s) in each generation scenario. This does not, however, feed back to the demand block in Figure 10.

Figure 11 compares the Commission’s demand forecasts with those of other modelers. Over the period to about 2040, the Commission’s central projection is for demand to grow by 50-60%, an increase of 20,000-25,000 GWh over current annual generation. The projected annual growth rate of around 1.2% reflects linkage to expected GDP growth, but with a steady exogenous improvement in efficiency. There are very wide uncertainty bands around this demand projection. At the lower end both Webb and Clover (2005) and MED (2006) estimated that major innovations on the demand side (high uptake of energy efficiency and distributed generation) could reduce required cumulative grid-connected generation growth to less than 40%; while the high-demand scenario in Webb and Clover (2005), with increased electricity intensity of the economy, might drive demand up by 70% over the three-and-a-half decades.

The Electricity Commission’s projected need for generation reaches 55,000 GWh by 2030 and 63,000 GWh by 2040, with the higher figure applying if there is a large shift towards electricity away from other fuels (due, for example, to

- hydrological uncertainty
- transmission network performance
- load variation

27 The scenario headed “demand side participation” in Table 3 below is based upon ad-hoc exogenous adjustments to the projected demand path rather than endogenous feedback from price within the model.
electrification of the transport vehicle fleet). Greenpeace (2007 p.34 Figure 13 and p.62 Appendix 2) similarly projects 59,000 GWh in 2040.

**Figure 11: Projections of Electricity Demand and Generation**


The least-cost capacity and generation to meet demand under the scenarios currently modeled by the Electricity Commission are summarized in Table 2, on the basis of results published in mid-2008 (Electricity Commission 2008b Chapter 6). The scenarios cover a range from the high-renewables “sustainable path”, MDS1 to a low-renewables “high gas discovery” case, MDS5. Over the period to 2040, the renewables share exhibits a low of 61% and a high of 88%. This reflects, at the low end, the minimum-renewables constraint imposed by already-installed hydro, geothermal and wind capacity; and at the high end the need to allow for cogeneration and least-cost (thermal) backup supply. No scenario to date has incorporated the 90% renewables goal as a binding constraint.
Table 2: NZ Electricity Commission Scenarios at June 2008

<table>
<thead>
<tr>
<th>Year</th>
<th>Scenarios</th>
<th>MDS1 “Sustainable Path”</th>
<th>MDS2 “South Island Surplus”</th>
<th>MDS3 “Medium Renewables”</th>
<th>MDS4 “Demand Side Participation”</th>
<th>MDS5 “High Gas Discovery”</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Installed capacity MW</td>
<td>8,553</td>
<td>8,553</td>
<td>8,553</td>
<td>8,553</td>
<td>8,553</td>
</tr>
<tr>
<td></td>
<td>Modelled generation GWh</td>
<td>41,079</td>
<td>41,069</td>
<td>43,067</td>
<td>41,075</td>
<td>43,074</td>
</tr>
<tr>
<td>2007</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2025</td>
<td>Total MW</td>
<td>12,488</td>
<td>12,481</td>
<td>10,899</td>
<td>10,934</td>
<td>10,934</td>
</tr>
<tr>
<td></td>
<td>of which renewable</td>
<td>9,395</td>
<td>9,161</td>
<td>7,317</td>
<td>7,164</td>
<td>7,084</td>
</tr>
<tr>
<td></td>
<td>renewable share %</td>
<td>79.6%</td>
<td>73.4%</td>
<td>67.1%</td>
<td>65.5%</td>
<td>64.8%</td>
</tr>
<tr>
<td></td>
<td>Total GWh</td>
<td>53,393</td>
<td>53,133</td>
<td>51,513</td>
<td>53,288</td>
<td>55,051</td>
</tr>
<tr>
<td></td>
<td>of which renewable</td>
<td>46,832</td>
<td>42,729</td>
<td>37,496</td>
<td>35,868</td>
<td>35,737</td>
</tr>
<tr>
<td></td>
<td>renewable share %</td>
<td>87.7%</td>
<td>80.4%</td>
<td>72.8%</td>
<td>67.3%</td>
<td>64.9%</td>
</tr>
<tr>
<td>2030</td>
<td>Total MW</td>
<td>13,532</td>
<td>13,286</td>
<td>11,239</td>
<td>11,916</td>
<td>11,459</td>
</tr>
<tr>
<td></td>
<td>of which renewable</td>
<td>10,899</td>
<td>9,676</td>
<td>7,692</td>
<td>7,244</td>
<td>7,285</td>
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<td></td>
<td>renewable share %</td>
<td>80.5%</td>
<td>72.8%</td>
<td>67.3%</td>
<td>60.8%</td>
<td>63.6%</td>
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<tr>
<td></td>
<td>Total GWh</td>
<td>57,147</td>
<td>56,187</td>
<td>53,035</td>
<td>56,991</td>
<td>58,103</td>
</tr>
<tr>
<td></td>
<td>of which renewable</td>
<td>50,239</td>
<td>44,705</td>
<td>38,349</td>
<td>34,957</td>
<td>37,566</td>
</tr>
<tr>
<td></td>
<td>renewable share %</td>
<td>87.9%</td>
<td>79.6%</td>
<td>72.3%</td>
<td>61.3%</td>
<td>64.7%</td>
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<tr>
<td>2040</td>
<td>Total MW</td>
<td>15,988</td>
<td>14,328</td>
<td>12,559</td>
<td>13,081</td>
<td>13,247</td>
</tr>
<tr>
<td></td>
<td>of which renewable</td>
<td>12,500</td>
<td>9,676</td>
<td>8,467</td>
<td>8,209</td>
<td>7,855</td>
</tr>
<tr>
<td></td>
<td>renewable share %</td>
<td>78.2%</td>
<td>67.5%</td>
<td>67.4%</td>
<td>62.8%</td>
<td>59.3%</td>
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<tr>
<td></td>
<td>Total GWh</td>
<td>66,223</td>
<td>63,066</td>
<td>59,917</td>
<td>65,826</td>
<td>65,029</td>
</tr>
<tr>
<td></td>
<td>of which renewable</td>
<td>55,662</td>
<td>45,106</td>
<td>42,116</td>
<td>39,875</td>
<td>39,854</td>
</tr>
<tr>
<td></td>
<td>renewable share %</td>
<td>84.1%</td>
<td>71.5%</td>
<td>70.3%</td>
<td>60.6%</td>
<td>61.3%</td>
</tr>
</tbody>
</table>


Figure 12 shows details of the Commission scenario that comes closest to the 90% target, namely scenario MDS1 “Sustainable Path”\(^{28}\). In this scenario the rapid expansion of wind and geothermal generation outpaces demand growth until the mid-2020s, when the renewables share reaches 88%. Renewables growth then

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\(^{28}\) The scenario “storybook” runs as follows: “New Zealand embarks on a path of sustainable electricity development and sector emissions reduction. Major existing thermal power stations close down and are replaced by renewable generation, including hydro, wind and geothermal backed by thermal peakers for security of supply. Electric vehicle uptake is relatively rapid after 2020. New energy sources are brought onstream in the late 2020s and 2030s, including biomass, marine, and carbon capture and storage (CCS). Demand-side response [details not specified] helps to manage peak demand.”
slows while demand continues to rise, bringing coal back into the picture and reducing the renewables share back to 84% by 2040.

Figure 12: Generation by Fuel, Electricity Commission Scenario MDS1

Source: as for Table 3.

Inspection of the Commission’s results highlights the importance of changes in, and the definition of, the denominator, in calculating a “renewables share”. Demand for electricity is affected by the same policy and relative-price forces as drive the changing generation portfolio. Scenario MDS1 actually has higher demand in 2040 than the other scenarios in Table 2, partly because of the assumed shift to electric vehicles in the transport sector with no change in the baseline energy-efficiency trend. In contrast the “High Gas Discovery” path has lower electricity demand because of substitution of direct gas use for electricity. This simultaneous impact of modelers’ assumptions on demand and supply makes “90% renewables” a moving target. Unhelpfully vague specification of the target by the Government to date has left this ambiguity unresolved.

5.2 Ministry of Economic Development modeling work
While the Electricity Commission’s published results do not enable construction of renewables/price reliability contours along the lines of Figure 6, work by the Ministry of Economic Development (MED 2006) has produced wholesale price estimates for a range of fourteen supply-demand scenarios out to 2030 with solutions at five-year intervals. These scenarios were designed to test a range of alternative assumptions about technological progress, feasibility of adopting identified renewable resources for electricity generation, and adoption of energy efficiency measures on the demand side of the market. Figure 13 (with the same axes as Figure 6 above) plots the wholesale price of electricity in each of the fourteen scenarios against the proportion of renewables in total electricity generated. The business-as-usual base case has only 69% renewables in 2025, with a wholesale price of 9.8 cents/kWh. Three of the alternative scenarios reach a renewables share of over 80%, and one has a share of 88%, with a price equal to the base case.

**Figure 13: Renewables Share and Wholesale Price**

![Renewables Share and Wholesale Price, MED 2006 scenarios at 2025](image-url)
Three of the MED scenarios in Figure 12 achieve over 80% of electricity generated from renewables: “Renewables”, “Renewable Electricity”, and “Additional Renewable Electricity” (MED 2006 pp.130-131, 99-102, and 102-104 respectively). The first and third of these have the same wholesale price as the 69%-renewable base case, which seems to hint at opportunities to shift the generation portfolio towards 90% renewables by 2025 with little or no consequent increase in the wholesale electricity price – the renewability/price contours appear to be flat or only shallowly-sloped across these scenarios.

The prominent high-cost outlier “Renewable Electricity” is not a like-with-like comparison relative to the other observations and has to be interpreted with care. For this scenario, the modelers assumed that policymakers intervene directly to reduce the use of fossil fuels in electricity, with no action in other energy sectors – an approach similar in some respects to the currently-proposed legislated moratorium. Under this assumption no new coal-fired plant is built, the sole existing coal-fired plant is closed in 2014, and no new gas-fired plant is built, although existing gas-fired generation remain in operation. A steep rise in wholesale price is then required to bring in large volumes of new high-cost hydro and wind generation, and some high-cost geothermal, to meet unrestrained demand growth. This scenario certainly raises the renewables share of generation, but at relatively high cost.

The lower-cost “Additional Renewable Electricity” scenario assumes relaxation of planning and land use constraints on the exploitation of renewable resources, allowing the model to build a large amount of moderate-cost renewable generation that would (in the modelers’ judgment) otherwise be ruled out by collateral damage to the environment. The renewables share then rises by 12 percentage points relative to the base case, with effectively no increase in wholesale price (marginal cost). Relative to the “Renewable Electricity” case,

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29 The treatment of geothermal in the MED scenarios is problematic, as it is given no credit for its ability to provide reliable baseload. Instead, the modellers assumed that it would be crowded out of the dispatch order for much of the time by must-run hydro and wind, on the basis that the latter have lower short-run marginal cost (MED 2006 p.100). In fact it is likely that geothermal would be bid in at a zero offer price designed to undercut wind and hydro.
the model results suggest that overcoming resource consent hurdles could bring the wholesale price down by a full 4 cents/kWh at the 2025 horizon, a reduction of 28%. Since the New Zealand Government has a reserve power under planning law to “call in” selected projects seeking planning consent, there exists a straightforward policy instrument that could effectively eliminate the cost of a drive to renewables, if the MED scenarios are taken as accurate.

The results from the “Renewables” scenario highlight the shortcomings of any policy that is limited to simply banning new fossil-fuel generation in electricity, with no supportive price-based measures to promote renewables and energy efficiency economy-wide. In this third scenario the MED modelers assumed that resource consents remain constrained as in the “Renewable Electricity” scenario, but they allowed for energy-efficiency improvements on the demand side, and the installation of 750MW of marine wave-power generation by 2025 at a cost of 10.2 cents/kWh. The results are dramatic: energy efficiency gains reduce the amount of generation required in 2025 by over 7,000 GWh (13%), so that even though total renewables generation is 2,000-3,000 GWh lower than in the other two renewable scenarios, the reduced demand enables fossil fuels to be squeezed to the margin of supply while keeping the wholesale price down equal to the business-as-usual base case.

The demand side of the market, thus, emerges as crucial to securing a swing towards 90% renewables at low cost without sacrificing the competing environmental and social values protected by the planning laws. Even with demand reductions, however, the MED results suggest that costs turn up sharply at around 90% renewables, with an incompressible residual tranche of fossil-fired capacity.

In 2007, MED and the Electricity Commission combined their models to evaluate a further set of policy scenarios designed to nudge the economy towards renewables (MED 2007b). Options explored included carbon taxes ranging from $15/tonne to $50/tonne, outright bans on fossil-fuel generation, and subsidies to renewables funded from consumers or from general taxation. Again, no scenario reached the 90% target (the highest was 88%). The fourteen scenarios are plotted in Figure 14 in ascending order of wholesale electricity
price. The height of each bar corresponds to the amount of generation required from the large generators in each case, with the “Improved Energy Efficiency” case at the left-hand side of the diagram with lowest generation and lowest price. The potential importance of demand-side savings in holding down the cost of a renewables-focused policy is clearly apparent, but this finding was not picked up in the subsequent Electricity Commission work discussed earlier.

**Figure 14: Fourteen Generation Scenarios for 2025 from MED (2007)**

![Diagram showing generation scenarios for 2025 ranked in order of wholesale electricity price.](image)

Source: calculated from Ministry of Economic Development (2007b)

Figure 15 uses the results from MED (2007b) to plot renewability/price contours. Renewables shares of generation ranging from 75% to nearly 90% turn out to be compatible with a wholesale electricity price only slightly above the 68%-renewable base case. At the high-renewables end of the range, the difference between a scenario which achieves 88% renewable generation by subsidies to renewables and one which achieves the same target by a $50/tonne emissions charge on generators (points A and B respectively in Figure 15) is 1.2 cents/kWh,
implying that the level of subsidy required to meet a 90% target could be of the order of less than 10% of the wholesale price.

In short, the evidence from recent modeling studies points to a nearly-flat apparent supply curve of renewability for the New Zealand case up to very close to 90%. This in turn means that implementation of price-based instruments such as the forthcoming carbon tax should be expected to elicit a high-elasticity response from the electricity supply side in terms of the composition of new investment, bringing the 90% target within easy reach.

**Figure 15**

![Renewables Share and Wholesale Price, MED 2007 scenarios at 2025](http://www.med.govt.nz/templates/MultipageDocumentTOC_31983.aspx)


5.3 *The long-run renewables supply curve*
The Electricity Commission’s preparation of its generation opportunities database turned up an unexpected wealth of opportunities - especially in wind resources, which are potentially in unlimited supply relative to national demand.\textsuperscript{30} The Commission has identified new renewable projects totaling over 6,400 MW at a long-run marginal cost of NZ$130/MWh or less, plus a further 13,000-plus MW of renewables that are either somewhat higher-cost, or cost-competitive but subject to other constraints in early development (see Table 3).

\begin{table}[h!]
\centering
\begin{tabular}{lcccccccccc}
\hline
\textbf{$/MWh} & 80 & 80-85 & 85 & 90-100 & 100-120 & 125 & 130 & Total & Other & Total potential \\
\hline
Geothermal & 250-300 & 400 & & & & & & 650-700 & 56-106 & 756 \\
Wind & 800 & 3,000 & & & & & & 3800 & 12,590 & 16,390 \\
Hydro & 200 & 200 & 600 & 400 & & & & 1400 & 537 & 1,937 \\
Biomass cogen & & & 150 & 150 & & & & 150 & & \\
Marine & & & 400 & 400 & & & & 400 & & 300 \\
Total MW & 250-300 & 800 & 600 & 200 & 3,000 & 600 & 400 & 400 & 150 & 6,400-6,650 & 13,183-13,233 & 19,533 \\
\hline
\end{tabular}
\caption{Scope of Feasible Renewable Projects}
\end{table}

\textit{Sources:} Electricity Commission 2008a pp.65-80 and 2008b pp.93-95; SSG 2008

Figure 16 constructs an approximate supply curve from this data for the 6,400MW that has been provisionally costed by the Commission. 6,000 MW of new renewable capacity is estimated to have life-cycle (long-run) cost of NZ$120/MWh or less; 5,000 MW of this is costed below $100/MWh. With very large volumes of wind potential still uncosted, the renewability supply curve appears likely to continue to flatten in the future.

\textsuperscript{30} Details of the database and the model are posted on the Commission website at http://www.electricitycommission.govt.nz/opdev/transmis/soo/08gen-scenarios/?searchterm=TTER and http://www.electricitycommission.govt.nz/opdev/transmis/soo
Gas and coal plant is estimated to have long-run marginal costs competitive with most of the renewables in Figure 16 only if gas is priced at $7/GJ (below the LNG benchmark) and if there is no carbon charge. A carbon charge of NZ$30/tonne would push thermal generation to or above the top of the range in the chart, making the full 6,400 MW of listed renewable generation competitive on cost, and relegating thermal to a support role as peaking plant and dry-year backup.

The conclusion is that New Zealand has sufficient hydro, geothermal and wind resources to bring the 90% renewables target within easy reach at little if any marginal cost penalty relative to fossil fuels, once carbon-emission externalities are priced in. The problem to be confronted in reaching the 90% target will not, therefore, be limited resource endowment. It will be, rather, institutional barriers and the overhang of legacy thermal capacity.

There is an apparently incompressible slice of non-renewable generation associated with cogeneration, sunk-cost existing capacity, and reliability
constraints in the absence of a responsive demand side, which does not fall as low as 10% in any of the Electricity Commission’s scenarios to date. Ironically, major gains in energy efficiency and consequently lower demand growth could make it more difficult, rather than less, to achieve 90% renewables. The less need there is for new large-scale generation plant to be built to meet demand growth, the larger will be the share of legacy plant in the portfolio, unless policymakers move to force the decommissioning of existing thermal capacity.

The perceived need to build new gas turbine capacity for backup purposes reflects to an unknown extent the Commission’s reluctance to contemplate demand-side measures that would enable consumers and distributed generators to respond to real-time price signals. This would seem to be a glaring gap in modeling and policy design in the New Zealand to date, reflecting strong supply-side bias in the present electricity market design.

6. Supply-side bias

The Electricity Commission is charged “to ensure electricity is produced and delivered to all consumers in an efficient, fair, reliable and environmentally sustainable manner”, subject to a Government policy that states31

… [e]lectricity efficiency and demand side management help reduce demand for electricity, thereby reducing pressure on prices, scarce resources and the environment. The Commission should ensure that it gives full consideration to the contribution of the demand side as well as the supply side in meeting the Government's electricity objectives…

The Commission has however in practice been almost entirely preoccupied to date with the supply side (large-scale remote generators connected to the transmission grid), and this has strongly coloured the nature of the modeling work it has conducted. The section of the Commission’s “transmission to enable

renewables” report that deals with “non-transmission alternatives” (Electricity Commission 2008a pp.39-41) contains no mention of downstream and demand-side options that might relieve grid constraints or strand grid-connected generators. This is particularly significant given the explicit instructions to the Commission in the most recent Government Policy Statement that modeling work should “enable identification of potential opportunities for ... transmission alternatives (notably investment in local generation, demand-side management and distribution network augmentation)” 32.

The long-established dominance of the electricity industry by the incumbent generators has been perpetuated in the mind-set of the Electricity Commission, and is reinforced by the reluctance of the New Zealand Government to tackle the barriers to entry faced by distributed generation and decentralized demand-side response in the present market structure (see Bertram 2007). This means that the 90% renewables target has to date been conceived of by policymakers almost exclusively in terms of the construction of new large-scale grid-connected generating plant.

Looking back to Figure 11, there is a yawning gap between the mainstream projected demand path and the low-demand scenarios of some analysts, suggesting that implementation of demand-side and distributed-generation options might cause substantial stranding of both grid-connected generation investment. The prospect of such a decentralization of effective supply could well drive a further tightening of the already stringently anti-competitive market rules, to keep small-scale entrants and consumers isolated from the lucrative wholesale and retail markets for electricity and protect the profitability of the incumbent generators and network operators.

7. Policy Instruments

Having articulated its strategic goal of achieving 90% renewable generation, the New Zealand Government has not yet settled upon a fully-credible set of policy instruments to pursue the goal. In particular, market-based instruments to drive a transition to renewables from the demand side of the electricity market are missing. Neither the UK adoption of regulated renewable quotas for electricity retailers (Cornwall, this volume) nor the Australian tradeable renewable quotas scheme (Office of the Renewable Energy Regulator 2008) have struck any chord with New Zealand policymakers.

For a generator who anticipates that the Government’s 90% goal may be abandoned and a lower renewables share allowed in the future, it may well be rational to proceed with new non-renewable generation projects, at least to the point of final decision on major expenditure. A considerable lead-time for major projects is required because of the need to secure planning consents for land use and emissions, and to complete design work and possibly install infrastructure for the new plant. The Government’s announcement of its moratorium on construction of new baseload thermal plant did not trigger any obvious abandonment of existing plans for new non-renewable generation.

Two major generators (Contact Energy at Otahuhu, and Genesis Energy at Huntly) have fossil-fired sites with planning consent already in place, and are in a position to build at quite short notice. Genesis Energy, meantime, is pressing ahead to secure planning consents for a new 400 MW CCGT plant at Rodney near Auckland. The ostensible moratorium on new construction seems likely to be circumvented by promoting the new plant under the loophole provisions in the legislation.

In the face of this direct challenge to its credibility the Government has appeared weak. The Minister of Energy has no direct powers to, even though Genesis is a state-owned company. The shareholding State-Owned Enterprises Minister sent a letter in October 2007 (Mallard 2007) informing all state-owned generators of the moratorium and asking to be kept informed of their plans; but the letter made it clear that no direct instruction would be issued by the Minister using his powers under the State-Owned Enterprises Act 1986, leaving Genesis effectively free to
proceed. (Contact Energy is privately owned and hence not subject even to this mild level of influence.) The test of whether the Government will grant an exemption or not for the Rodney project is still to come.

8. Conclusion

New Zealand remains some distance from full policy commitment to a renewable future; but the direction in which market forces will push the country’s electricity sector seems increasingly well-defined and can be expected to deliver something close to the 90% target with minimal policy activism beyond the emissions tax.

This is a reversal of the dominant trend of the last half-century. At the time when many countries began to move away from dependence on fossil fuels under the spur of high oil prices in the 1970s, New Zealand embarked on a deliberate programme of raising the fossil-fuel intensity of its economy to take advantage of its windfall of domestic natural gas. Only as gas prices began to rise from 2003 on with depletion of the Maui field, accompanied by an upward trend in the electricity wholesale price, have the economics of geothermal become attractive again, while the rapidly falling cost of wind generation has triggered a windfarm boom.

The New Zealand Government’s current approach of placing a blanket restriction on the construction of new baseload fossil-fired capacity runs the risk of leaving sufficient already-operating legacy thermal capacity in place to supply more than 10% of total generation in 2025, unless some further restriction is placed upon the ability of thermal plant to bid for dispatch. To some extent the planned carbon tax will provide that restriction, but the possibility of more direct restraint on the operation of thermal plant cannot be ruled out if the 90% goal is seriously pursued.

Long suppressed by policymakers and the dominant generators, the potential for small scale distributed generation and for an active, responsive demand side will become a problem rather than a support for the 90% target if central generation is overbuilt and then stranded by an eventual demand-side renaissance.
Policymakers would be well advised to take proper stock of their demand-side options earlier rather than later.

References


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Insofar as price-responsive demand side options can be brought into the market, with real-time price incentives, there is good evidence from modelling work internationally that they are often more cost-effective than, for example, installation of quick-response supply-side options such as open-cycle gas turbines. The GreenNet modelling project carried out for the European Commission found, for example, that demand response could reduce the system cost of maintaining capacity margins in a high-wind-penetration scenario to as little as 25% of the cost of the thermal-generation equivalent (Auer et al p.18 Figure 6.5; see also Klobasa and Ragwitz 2006.)

This suggests that small islanded systems should be especially eager to maximise demand-side flexibility and load management. Ironically, although demand-side measures were willingly developed in New Zealand half a century ago, they have been shut out of the new “deregulated” market by a complex rulebook drafted by and for the dominant large generation companies, combined with the absence of any pro-competitive regulations requiring retailers to post feed-in tariffs or make other provision for small independent suppliers to reach customers.

In the 1950s, with demand growth outstripping supply, there was an urgent requirement for controlled load-shedding to reduce the incidence of general blackouts, and at that time most residential customer meters incorporated ripple-control switches, which enabled the local distribution networks to shed load by switching off water heaters at times of stress. These water-heating switches remain in operation across a substantial part of the retail market, but there has been no attempt by policymakers in the post-restructuring era to introduce new-generation smart metering technology to a uniform standard, or to enforce access to retail customers (or, for that matter, to the wholesale market) for small distributed generators. Unless this hands-off policy stance changes, the policy drive towards 90% renewable generation will be apt to come up against an irreducible need to maintain and operate fossil-fuel generators in order to maintain reliability of supply and load-following capability.