Final Report

Policy Options to Encourage Renewable Supply

Prepared for

Ministry of Economic Development
and the
Energy Efficiency and Conservation Authority

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Executive Summary

This report examines policy measures that can provide incentives for greater use of renewable sources of energy for stationary uses. This includes renewable energy used for electricity generation and for heat by industry and households. The study responds to a request from MED and EECA to examine a number of issues pertaining to renewables supply. It is not a comprehensive review of policy measures; nor does it evaluate the government's objectives, eg whether simply to reduce greenhouse gas emissions at least cost or to address a wider set of objectives that might add to the desirability of renewable energy. These issues are to be addressed in the New Zealand Energy Strategy (NZES). This report is limited to examining measures that could be used to encourage renewables, regardless of the objectives.

The instruments operate very broadly in one of three ways, through:

1. **changing the costs of alternatives**—these are measures that increase the costs of supply of thermal fuels and thus change the costs of renewables relative to thermals. Measures include carbon charges/tradable permits or charges on the use of thermal fuels;

2. **changing supply costs for renewables**—these are measures that reduce the costs of supply of renewables via subsidies;

3. **introducing new markets for renewable energy**—these measures differentiate renewables from other forms of energy and encourage demand. They include sales obligations and voluntary mechanisms which simply enable differentiation through labelling. They also include feed-in tariffs which specifically target renewable energy to receive a guaranteed price.

Individual instruments that fall under these different categories and which are expected to be effective in incentivising more renewables are listed below.

Table ES1 Policy Options

Options	Interventions
Correcting Market Failures	Carbon taxes
Changing Costs of Alternatives	Carbon taxes Thermal fuel taxes
Changing Supply costs	Capacity/capital subsidies
Introducing new markets	Sales obligations—capacity Sales obligations—generation Production subsidies (feed-in tariffs)

Whichever policy instrument is used to encourage renewables it is likely to lead to the same resource costs for a given quantity of additional renewable entry that results; this is the additional cost of renewables over the costs of alternatives displaced. However, the instruments differ in a number of important aspects that affect their economic efficiency and likely effectiveness.

Is anything more required than a price on carbon?
A price instrument such as a carbon charge or a cap and trade system would encourage the introduction of more renewable energy in all sectors. In theory it would lead to optimal investment in renewable capacity. If the reason for introducing policy to encourage renewable energy is to address climate change, and the government is indifferent about how much renewables capacity there is, then a carbon price instrument is the only instrument required.

If additional quantities of renewable generation are desired, for whatever reason, then using a price instrument may not be least cost, because it would have other effects also. These include fuel switching amongst thermal fuels, eg from coal to gas.

Should price or quantity instruments be used?
Price instruments include charges on carbon or energy, and subsidies paid to encourage additional capacity or additional renewable generation. Quantity instruments include obligations that could be applied to specific firms or sectors requiring them to meet quantity obligations, eg a specified level of capacity installations in a time period. The obligations would be met by holding certificates that verify that capacity exists or that renewable generation has occurred.

In general, price and quantity instruments can be specified in similar ways, but price instruments give greater cost certainty but outcome uncertainty, whereas quantity instruments give certainty on quantity but uncertainty on cost.

The quantity instruments also enable the government to pass the costs on to industry whereas subsidies require government funding.

Should the cost be borne by industry or government?
Wherever the costs are borne initially, generally they can be passed on, so the question may be better specified as whether costs should be borne by consumers or tax payers. One of the reasons for introducing policies to encourage renewables is because of market failures. The cost of measures to correct externalities is a legitimate cost to be borne by the industry. Where the costs go beyond this level, arguably it is to meet other (unspecified) benefits that are shared by society at large and more legitimately would be borne by tax payers.

This would suggest the suitability of a combination of a carbon charge (or cap and trade) and a subsidy for capacity or generation. However, if a carbon charge is not introduced, this combination of measures can be approximated by an industry obligation. It would require a firm to ensure that capacity existed (or generation occurred); the level of obligation would change with the plant output of energy (electricity or heat) or emissions of CO_2.

Capacity or generation?
There are advantages to both capacity and generation obligations that depend on the sector being targeted. For electricity, a reduced amount of payment would be required on a capacity basis to support renewable entry compared with what would be required

as a payment on a generation basis, largely because of policy uncertainty over future payments. A capacity-based system could also include the residential sector. However, for industrial use of renewables, capacity cannot necessarily be restricted to a specific fuel type and a generation payment is required.

Should all renewables be included or only new capacity?
Some instruments provide payments to all renewables including existing capacity. Such approaches have been used in other countries, particularly where the renewable industry is in its infancy. In New Zealand there is a large existing renewable capacity and support payments to existing capacity, either as part of a government subsidy or in response to an obligation, will lead to significant transfers of wealth. This is unnecessary, will lead to excessive profits and is inefficient where there is a cost to raising revenues. Instruments should be limited, to the extent possible, to providing support to new capacity.

Do the effects on final prices matter?
The analysis suggests that the instruments differ with respect to the impacts on electricity prices and transfer prices within industries. Measures that impose a cost at the margin, either as a carbon or energy charge, a cap and trade scheme, or a renewable obligation that is based on total activity (MWh of electricity or heat), lead to increases in prices. In contrast, those measures that simply provide support for new capacity, either as government subsidies or obligations that are based on a firm's capacity, will lead to reductions in electricity prices.

What is better depends on the objectives, but we assume that efficient pricing is desirable. Efficient pricing of electricity occurs when prices reflect marginal costs of supply. Prices are regarded as most efficient when, on average, they equal long run marginal costs of supply, and this should incorporate the costs of carbon and other externalities. This is achieved if prices reflect the costs of entry (including carbon costs). This is most obviously achieved using a carbon charge or a cap and trade scheme.

If a carbon charge is introduced then ideally any additional instrument would not pass further costs on to electricity prices. This could be achieved either using a subsidy or a (capacity or generation) obligation based on capacity, ie an obligation to provide either additional generation or additional capacity where the obligation was proportional to the capacity of the firm. An obligation that was proportional to production would be more appropriate only in the absence of a carbon charge. This is because such an obligation would impose costs on marginal activity and thus lead to an increase in electricity prices.

How should the expected design of long run measures be taken into account?
It is most likely that, in the long run, greenhouse gas emissions will be tackled in a least cost way involving a comprehensive price instrument such as an allowance trading system (cap and trade). There is some risk that renewables support policies, introduced as interim measures, may lead to outcomes that are not consistent with the long run response. The greatest risk is if the interim measure provides high rewards per unit output from a renewable plant and that this high level of return is not sustained under a

future carbon price instrument. In the electricity generation sector, the risk is not that of stranded assets. Rather, it is a risk that these plants will receive an inadequate return on capital. In contrast, for industrial uses of renewables there is some risk of stranded assets. This is because renewable fuels have a cost and their price relative to thermal fuels may be lower under a renewables support measure than a carbon price instrument. To ensure greater compatibility, instruments should be designed such that the marginal reward to a renewable plant is similar to, or at least is not higher than, that expected under a long run instrument.

Recommendations

A carbon charge or equivalent price instrument, eg a cap and trade scheme, is the most economically efficient instrument to tackle greenhouse gas emissions. It would provide incentives for an optimal quantity of renewables consistent with an objective of reducing greenhouse gases at least cost.

If additional quantities of renewable capacity and/or generation were targeted beyond those achieved by an efficient price instrument, instruments should be chosen that do not pass on a cost at the margin. Most appropriately this would be a subsidy system, given that electricity sector costs are largely internalised, and would apply on a capacity basis to electricity generation and residential use of renewables, and on a generation basis for industrial use of renewables. Alternatively an obligation of a similar form could be used, with the level of obligation proportional to plant (firm) capacity.

If no price instrument is introduced, then the most appropriate instrument would be an obligation to supply capacity (electricity generation and households) and generation (industrial use) in which the level of obligation was based on the activity levels in the electricity and industrial sectors.

Whichever instrument is used, there are benefits from policy certainty and stability over time. This might suggest using instruments that are based on legislation rather than contract, particularly for instruments that result in payments to new entrants on generation rather than capacity. However, if renewables support measures are regarded as interim measures only in a transition to a more comprehensive price instrument to tackle greenhouse gas emissions, then the emphasis should rather be ensuring compatibility with the long run measure. This would best be achieved through aiming for consistency in the level of reward at the margin to output from renewable plants.

1. Introduction

1.1. Background

This report examines policy measures that can be used to provide incentives to encourage the greater use of renewable sources of energy for stationary uses. This includes renewable energy used for electricity generation and for heat by industry and households. The study responds to a request from MED and EECA to examine a number of issues pertaining to renewables supply. It is not a comprehensive review of policy measures; nor does it evaluate the government's objectives, eg whether simply to reduce greenhouse gas emissions at least cost or to address a wider set of objectives that might add to the desirability of renewable energy. These issues are to be addressed in the New Zealand Energy Strategy (NZES). This report is limited to examining measures that could be used to encourage renewables, regardless of the objectives.

New Zealand has no policies currently specifically to encourage renewables. It has a significant proportion of renewables in electricity supply, very largely built under historical state ownership of the electricity supply industry.[1] However, currently, renewable generation must compete against other generation options in the wholesale market both for entry and generation. In contrast, other governments have introduced a wide range of instruments to encourage renewable supply. These include:

- Instruments to tackle underlying market failures that provide an indirect incentive for renewable supply.
- Charges on alternative fuels that incentivise renewables.
- Obligations to generate, sell, or use renewable energy or to install renewable capacity.
- Subsidies in the form of guaranteed prices, tax incentives or investment grants.

Figure 1 lists a number of policy options that have been adopted in developed and transition countries; definitions of the terms used in this chart are provided in Annex B.

The policies adopted in other countries have had mixed success, and some have been costly in achieving their aims. A recent analysis by Oxford Economic Research Associates (Oxera), for example, estimates that internal rates of return for investment in renewable technologies in a number of countries has reached very high levels as a result of support policies (Table 1).

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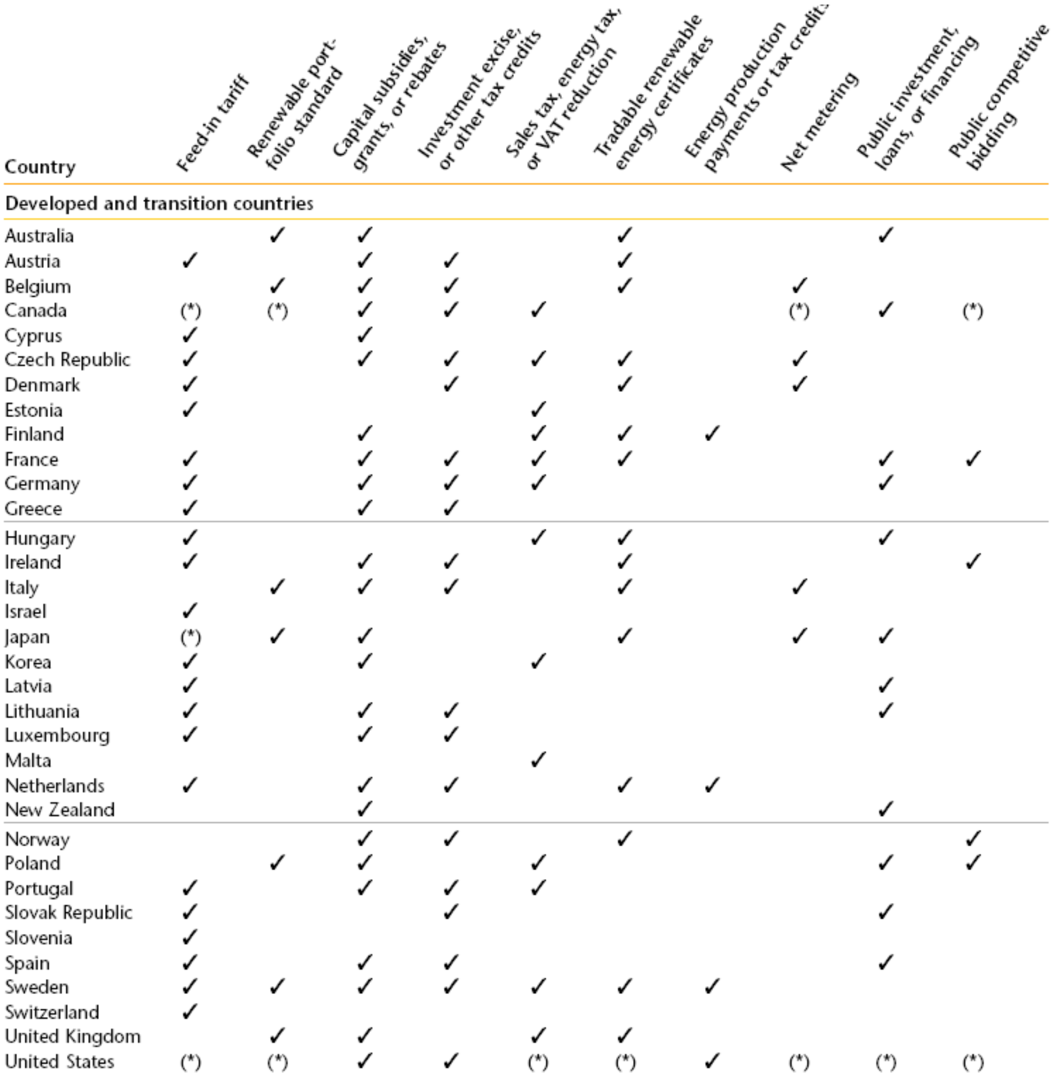
[1] It is difficult to tell whether this would have been built under alternative ownership regimes.

Table 1 Internal Rate of Return for Investors in Onshore Wind—With Policy Scenarios

Country	%
Denmark	9 – 30
Finland	7 – 20
Germany	20 – 42
Spain	15 – 31
UK	16 – 33

Source: Oxera (2005) Renewable support policies in selected countries. Report prepared for National Audit Office.

Figure 1 Renewable Energy Policies in Developed and Transition Economies



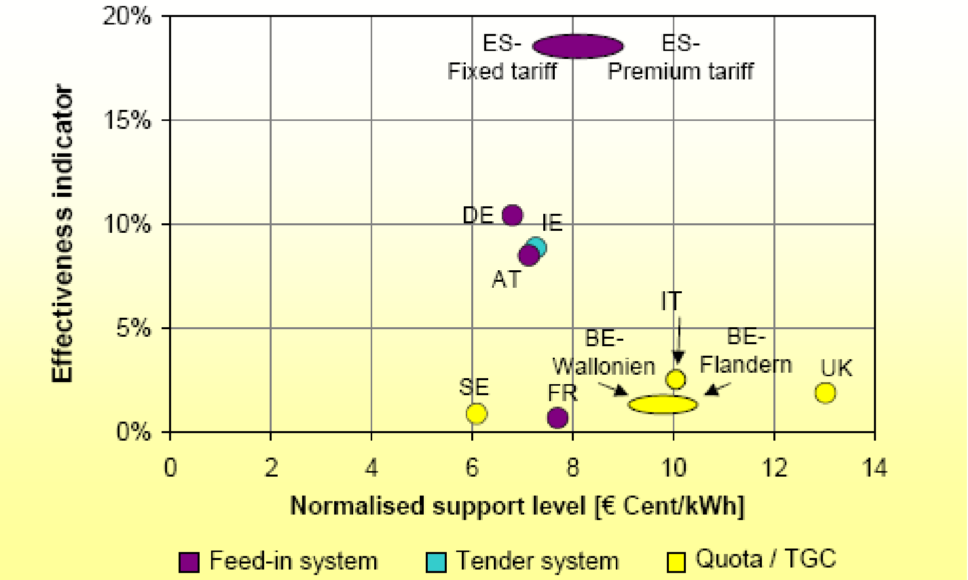
Country	Feed-in tariff	Renewable portfolio standard	Capital subsidies, grants, or rebates	Investment excise, or other tax credits	Sales tax, energy tax, or VAT reduction	Tradable renewable energy certificates	Energy production payments or tax credits	Net metering	Public investment, loans, or financing	Public competitive bidding
Developed and transition countries										
Australia		✓	✓			✓			✓	
Austria	✓		✓	✓		✓				
Belgium		✓	✓	✓		✓		✓		
Canada	(*)	(*)	✓	✓	✓			(*)	✓	(*)
Cyprus	✓		✓							
Czech Republic	✓		✓	✓	✓	✓		✓		
Denmark	✓			✓		✓		✓		
Estonia	✓				✓					
Finland			✓		✓	✓	✓			
France	✓		✓	✓	✓	✓			✓	✓
Germany	✓		✓	✓	✓				✓	
Greece	✓		✓	✓						
Hungary	✓				✓	✓			✓	
Ireland	✓		✓	✓		✓				✓
Italy		✓	✓	✓		✓		✓		
Israel	✓									
Japan	(*)	✓	✓			✓		✓	✓	
Korea	✓		✓		✓					
Latvia	✓								✓	
Lithuania	✓		✓	✓					✓	
Luxembourg	✓		✓	✓						
Malta					✓					
Netherlands	✓		✓	✓		✓	✓			
New Zealand			✓						✓	
Norway			✓	✓		✓				✓
Poland		✓	✓		✓				✓	✓
Portugal	✓		✓	✓	✓					
Slovak Republic	✓			✓					✓	
Slovenia	✓									
Spain	✓		✓	✓					✓	
Sweden	✓	✓	✓	✓	✓	✓	✓			
Switzerland	✓									
United Kingdom		✓	✓		✓	✓				
United States	(*)	(*)	✓	✓	(*)	(*)	✓	(*)	(*)	(*)

(*) = State or province level policies but no national policies

Source: REN21 Renewable Energy Policy Network (2005) Renewables 2005 Global Status Report. Worldwatch Institute. Washington DC.

Other analyses have shown that a number of countries that have introduced high cost policies (Italy, UK, Belgium) have seen low growth rates in renewable supply.[2] Figure 2 shows the results of a recent analysis by the German-based Fraunhofer Institute of the relationship between the level of support offered and effectiveness. The level of support is normalised to take account of the different durations of support, eg the Italian system provides high support for the first eight years of plant life. Effectiveness is measured as the change in renewable energy potential (ie growth in capacity—what potentially could be generated from existing plants) as a proportion of total future potential to 2020 as estimated by independent analysis.

Figure 2 Relationship between support level and effectiveness



Source: Fraunhofer Institute Systems and Innovation Research and Energy Economics Group (op cit)

The consultants concluded from this analysis and an examination of the history and context of policy in different countries that, amongst other things, policy stability was a key criterion in determining effectiveness. The analysis also suggested that feed-in tariffs had been more successful than obligation mechanisms in encouraging new supplies and at lower levels of financial support.

1.2. Current Status of Renewables in New Zealand

Figure 3 shows renewables supply in total primary energy supply (TPES)[3] in New Zealand. The renewables contribution to TPES has been relatively stable over time. Figure 4 shows the renewables contribution to consumer energy. The difference in the total is because of the treatment of geothermal energy in TPES; it is assumed to have an efficiency of 15% whereby contribution to TPES is escalated. Renewables energy use in

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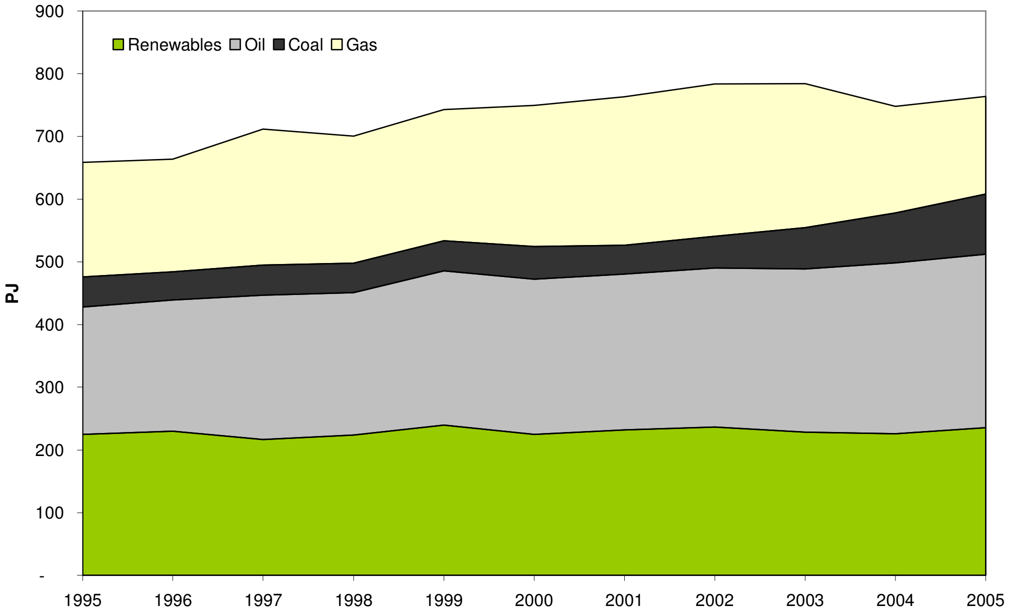
[2] Fraunhofer Institute Systems and Innovation Research and Energy Economics Group (2005) Monitoring and evaluation of policy instruments to support renewable electricity in EU Member States. Summary Report. A research project funded by the German Federal Ministry for the Environment, Nature Conservation and Nuclear Safety.

[3] The amount of energy supplied in a year that is either consumed, transformed or lost (as heat, leakage etc)

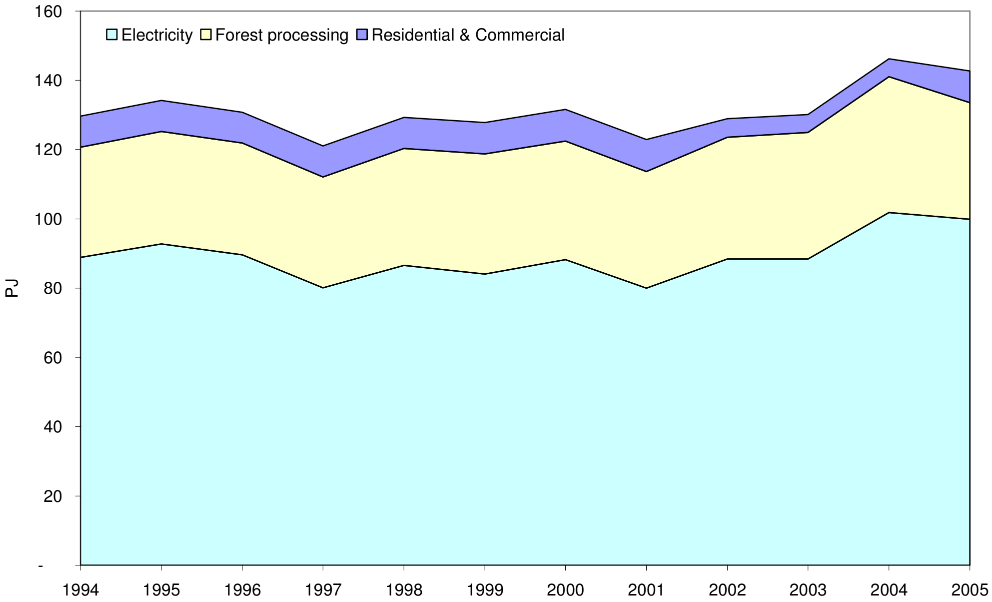
New Zealand is dominated by electricity production, followed by wood waste and black liquor used in forest processing, particularly heat generation for pulp and paper production and timber drying.[4] Wood and geothermal is used for heating in the residential and commercial sectors.

Figure 3 Primary Energy Supply



Source: MED. Energy Data File

Figure 4 Renewables in Consumer Energy



Source: MED Energy Data File. December year data apart from 2005 (= September year)

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[4] The Energy Data File does not assign renewable energy use by industry to any specific industrial sector. Analysis of energy use by forest processing suggests that this industry is responsible for this consumption.

1.3. Prospects for Renewables

1.3.1. Electricity Generation

New Zealand is comparatively well placed to achieve increases in renewable supply at relatively low cost, particularly in electricity generation. Table 2 provides estimates of the costs of entry of a number of different new plant types, both renewable and thermal capacity. However, this is somewhat misleading because costs are provided as point estimates; in practice there are numerous site specific factors that determine both the plant type that is chosen (eg lignite in the South Island only) and the costs (eg site specific connection costs). To demonstrate this, the entry costs data are presented in Figure 5 with costs grouped under broad categories of plants. It shows that the renewable options can be low cost but within the range of possible costs for hydro and wind plants, in particular, are costs for thermal plants, both gas (combined cycle gas turbine or CCGT) and coal.

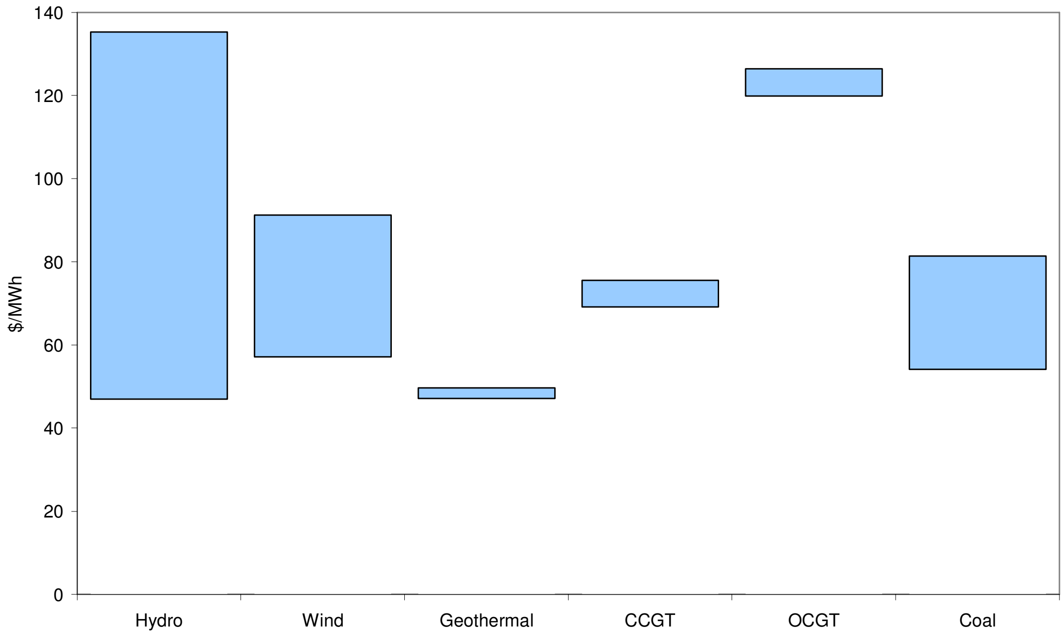
Table 2 New Plant Cost Assumptions

Plant type	Gross Efficiency[1] (%)	Assumed load factor (%)	Capacity (MW)	Time to build (years)	Capital Cost ($/kW)	Fixed cost ($/kW/yr)	Variable cost ($/MWh)	Fuel cost ($/MWh)	Average Cost ($/MWh)
Coal (including flue gas desulphurisation, FGD)									
Subcritical pulverised coal (bituminous)	34	90	150	3	2420	31	3.1	37.2	81.4
Supercritical pulverised coal (bituminous)	38	90	500	3	1850	31	3.1	33.2	68.7
Supercritical pulverised coal (bituminous)	38	90	150	3	2500	31	3.1	33.2	78.7
Supercritical pulverised coal (lignite)	36	90	500	3	2030	35	3.4	15.0	54.1
Supercritical pulverised coal (lignite)	36	90	150	3	2750	35	3.4	15.0	65.2
Supercritical pulverised coal (sub-bituminous)	38	90	500	3	1920	31	3.1	37.9	74.5
Gas									
Combined Cycle Gas Turbine (CCGT)	47	90	250	2	830	17	2.1	59.1	75.6
Advanced CCGT	54	90	400	2	940	14	2.1	51.5	69.1
Open Cycle Gas Turbine (OCGT)	33	25	160	1	630	14	4.1	84.2	126.4
Advanced OCGT	37	25	230	1	720	12	3.1	75.1	119.9
Renewable									
Small hydro (low cost)	100	55	50	3	1500	15	6.0	0	45.0
Small hydro (medium cost)	100	55	50	3	3000	15	6.0	0	84.8
Small hydro (high cost)	100	55	50	3	5000	15	6.0	0	135.3
Wind (50% Load Factor)	100	50	50	1	1760	30	6.0	0	57.1
Wind (40% Load Factor)	100	40	50	1	1760	30	6.0	0	69.9
Wind (30% Load Factor)	100	30	50	1	1760	30	6.0	0	91.2
Geothermal (small)	15	100	25	1	3000	30	6.0	0	47.2
Geothermal (medium)	15	100	50	1	3200	30	6.0	0	49.7

[1] Based on Higher Heating Value (HHV)

Source: East Harbour Management Services (2004) Fossil Fuel Electricity Generating Costs. Prepared for MED; East Harbour Management Services (2005) Availabilities and Costs of Renewable Sources of Energy for Generating Electricity and Heat. 2005 Edition. Prepared for MED; Marsden A, Poskitt R and Small J (2004) Investment in New Zealand Electricity Industry. An examination of comparative financial performance, pricing, and new entry conditions; and a discussion of the principles of new investment. Auckland Uniservices Limited

Figure 5 Cost Ranges for New Entrants



The fuel cost assumptions used in this analysis are shown in Table 3.

Table 3 Fuel Price Assumptions ($/GJ)

Fuel	2006	2010	2015	2020	2030
Sub-bituminous	4	4	4	4	4
Bituminous	3.5	3.5	3.5	3.5	3.5
Lignite	1.5	1.5	1.5	1.5	1.5
Gas	6.19	7.01	8.20	9.58	9.58

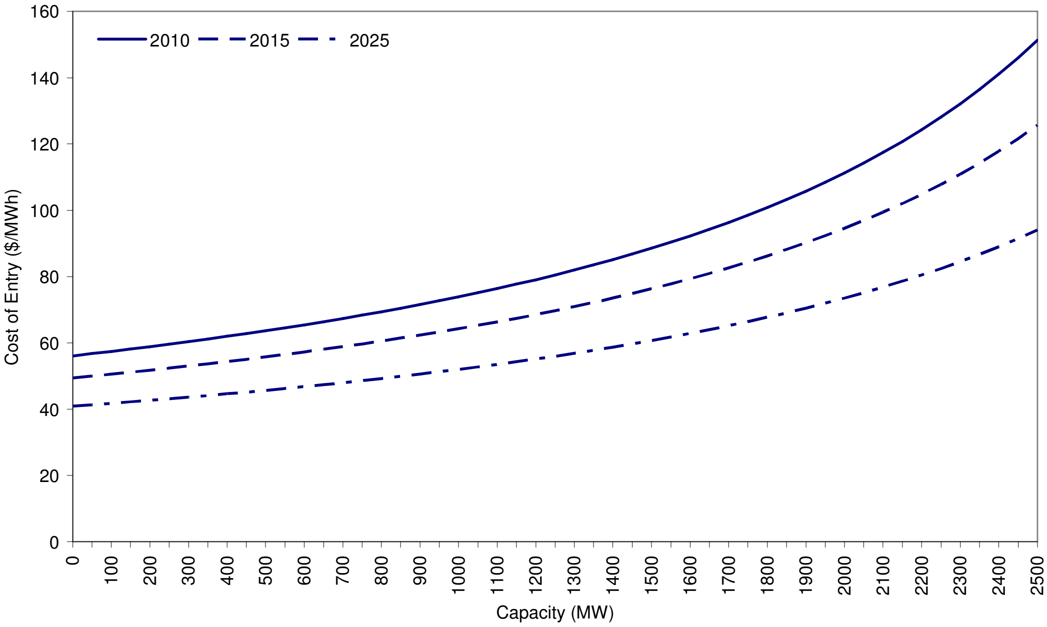
In addition to site specific factors, or related to them, the costs of wind entry differ with capacity installed and time—the capital costs are forecast to fall and initially the best (windiest) sites are used followed by successively less windy sites. The starting point for this analysis is the national supply curve data provided by East Harbour (see Annex A). The impacts are shown in Figure 6.

Recently the capital costs of wind plant installations have increased on the basis of two factors: decreases to the value of the New Zealand dollar and the current global balance of supply and demand for turbines. The capital costs analysis presented here was developed by East Harbour using a US$0.6:NZ$1 exchange rate which is very close to the current rate and the current excess demand for turbines is regarded as a short term issue for which there will be a market response—increased supply. The analysis here is therefore applicable over the medium term.

There have also been reports of increases in the cost of geothermal generation. These cost increases have not yet been captured in the costs above, though it is noted that substantial increases will be required before geothermal energy is no longer competitive.

The analysis suggests that low cost renewable electricity supply is available in New Zealand but that within the range of costs for renewable installations, there are thermal plant options that are viable also. These results are consistent with what is happening currently in New Zealand, ie there are a number of new plant opportunities being pursued currently spanning the whole range of plant types shown in Figure 5.

Figure 6 Cost of Wind Entry as a Function of Installed Capacity



In addition to the existing technologies, there are a number of emerging technologies that have the potential to be additional sources of renewable energy in the future. Some are listed in Table 4 alongside estimates of average costs of generation. The estimates include initial cost estimates, ie on first entry as pilot projects, and as mature technologies.

Table 4 Costs of Emerging Technologies

	Capital Costs ($/kW)		Load Factor		O&M Cost ($/MWh)		Average Costs ($/MWh)[1]	
	Initial	Mature	Initial	Mature	Initial	Mature	Initial	Mature
Wave	4400 - 5500	1200-2800	25%	40%	65	40	203 - 238	78 - 128
Tidal	6000 - 9000	2500 - 3500	30%	40%	60	30	249 - 343	109 - 140
Fuel Cells	4500 - 8000	1600 - 2400	90%	95%	45 - 71	11	105 - 177	32 - 43
Photovoltaics	7000 - 11000	3500 - 6500	10%	20%	125	40	565 - 817	260 - 449

[1] Assessed over 25 years at a 10% cost of capital

Source: Capital cost, load factors and O&M cost data sourced from PB Technologies (2006) Emerging Supply-Side Energy Technologies. Prepared for Ministry of Economic Development.

These also need to be set against possible changes to the prices of thermal technologies under the influence of future prices for CO_2 and other greenhouse gas emissions. For comparison Table 5 shows the impacts of CO_2 charges on the average costs of generation from the different thermal plants. With increasing prices of carbon, it is more likely that renewable energy options will be the lower cost generation choices.

Table 5 Impacts of Carbon Charges on Thermal Fuel Generation Costs

Coal (including flue gas desulphurisation, FGD)				
Subcritical pulverised coal (bituminous)	81.4	95.6	105.0	128.6
Supercritical pulverised coal (bituminous)	68.7	81.4	89.8	110.9
Supercritical pulverised coal (bituminous)	78.7	91.4	99.8	120.9
Supercritical pulverised coal (lignite)	54.1	67.5	76.4	98.7
Supercritical pulverised coal (lignite)	65.2	78.6	87.5	109.8
Supercritical pulverised coal (sub-bituminous)	74.5	87.2	95.6	116.7
Gas				
Combined Cycle Gas Turbine (CCGT)	75.6	81.2	85.0	94.5
Advanced CCGT	69.1	74.1	77.4	85.6
Open Cycle Gas Turbine (OCGT)	126.4	134.5	139.9	153.4
Advanced OCGT	119.9	127.1	131.9	144.0

CO_2 prices are likely to apply to geothermal electricity generation also, although the details will depend on whether or not the emissions are regarded as fully (or in part) anthropogenic, ie whether they would have arisen anyway in the absence of electricity generation from the geothermal resource. Emissions from geothermal resources are in the range of 0.03-0.6 kg/kWh, with an average of 0.1 kg/kWh,[5] compared to approximately 0.4kg/kWh for a CCGT and 0.8-1.0kg/kWh for coal.

1.3.2. Industrial Heat

Use of renewable fuel for industrial heat is dominated by wood wastes and geothermal energy used in the timber processing industry. The major growth opportunities are for additional supplies of forest trimmings to this same industry. This is being increasingly examined because of increases in prices of gas as a fuel source for these firms. However, wood waste cannot be used in many existing heat plants, including gas and coal-fired plants. Wood waste requires a boiler with a grate whereas many of the coal-fired boilers use pulverised coal in which coal is ground (pulverised) to a fine powder which is blown with part of the combustion air into the boiler plant; it requires no grate.

Expanding the use of renewable energy for industrial heat plant will require the construction of new plants. This is easier when a sector is expanding; however, for a number of reasons including levels of timber supply and current production economics, the timber processing industry is not expected to expand in the future. There has been some shift towards on-site generation of electricity rather than importing grid electricity, including a planned 70-80MW geothermal plant at Kawerau.

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[5] : East Harbour Management Services Ltd (2005) Availabilities and Costs of Renewable Sources of Energy for Generating Electricity and Heat. Report to the Ministry of Economic Development. and Covec calculations

1.3.3. Residential Heat

Residential heat includes the use of wood and geothermal (including geothermal heat pumps).[6] The major growth prospects are in increased use of wood and fire-logs made from wood residues, as heat sources in solid fuel burners.

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[6] White G (2006) An Assessment of Geothermal Direct Heat Use in New Zealand. New Zealand Geothermal Association Inc. Available at: www.nzgeothermal.org.nz/publications/Reports/NZGADirectHeatAssessmentReport_2006.pdf

2. Policy Options

This section analyses the different potential policy options to understand which might be the best options for application in New Zealand. It sets out the broad policy options and the criteria that will be used for analysis. It then analyses each intervention in turn.

2.1. Options and Approach to Analysis

2.1.1. Options

The government's objectives for energy are being developed in the New Zealand Energy Strategy to respond to the long term challenges of energy security and climate change. Renewable energy is an important component of the long run response because:

- renewable sources of energy are generally domestic sources and their use contributes towards self-sufficiency and, potentially, to energy security;

- renewable sources of energy are either carbon free or low in carbon.

The justification for government intervention to increase the supply of renewables is based on market failure—the market undervalues security or fails to price greenhouse gases such that renewable energy sources are under-provided.[7, 8] This is not a blanket rationale for any intervention; each should additionally provide benefits in excess of its cost. In this context, the starting place for considering instruments to encourage renewables is a set of measures that address the underlying market failure. Such an approach could provide incentives for renewables and other potential solutions. These policy options are considered below in the form of market solutions to security and to greenhouse gas emissions. Secondly, other measures seek directly to increase the quantity of renewable energy that is supplied and operate very broadly in one of three ways, through:

1. **changing the costs of alternatives**—these are measures that increase the costs of supply of thermal fuels and thus change the costs of renewables relative to thermals. Measures include carbon charges or charges on the use of thermal fuels;

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[7] Correcting a market failure relating to security of supply does not lead automatically to a solution involving more renewables, but as discussed further in Section 2.4, if additional capacity is targeted as a solution, renewables capacity is likely to be part of that.

[8] In the case of greenhouse gas emissions, the externality in the context of international agreements on climate change (the Kyoto Protocol and successive agreements) is that emitting places a burden on New Zealand as it must meet a defined target, set initially through negotiation and modified through trade in assigned amount units or their equivalents. At the margin, the cost to New Zealand of emissions is the international price of allowances such as the products of the Kyoto mechanisms used to modify the national target.

2. **changing supply costs for renewables—**these are measures that reduce the costs of supply of renewables via subsidies;

3. **introducing new markets for renewable energy—**these measures differentiate renewables from other forms of energy and encourage demand. They include sales obligations and voluntary mechanisms which simply enable differentiation through labelling. They also include feed-in tariffs which specifically target renewable energy to receive a guaranteed price.

Individual instruments that fall under these different categories are listed in Table 6.

Table 6 Policy Options

Options	Interventions
Correcting Market Failures	Carbon taxes Energy capacity markets/measures
Changing Costs of Alternatives	Carbon taxes Thermal fuel taxes
Changing Supply costs	Capacity/capital subsidies
Introducing new markets	Sales obligations Production subsidies (feed-in tariffs) Labelling

2.1.2. Transition to a Long Run Measure

Renewables support policies are being examined in the absence of any existing cross-sectoral measures that might be adopted in the future to address climate change. There are strong arguments for introducing a comprehensive price-based measure because it would be a way to achieve emission reductions at least cost. The benefits of such an instrument would increase if and when international markets for emission allowances develop as this provides clarity on the appropriate level to set such an instrument or a market with which a domestic trading scheme could interact. There are various forms that such an instrument could take and the architecture could vary with respect to the mechanism (charge-based or allowance-based), the sectors or sources covered and the stringency. The benefits of some of these design components will become clearer as negotiations for the next phase of international commitments take place.

If such an instrument, or set of instruments, is likely to be introduced in the future, long run costs, particularly adjustment costs, can be minimised through taking account of the likely architecture in the design of interim instruments. This includes institutional arrangements, potential for capacity building amongst industry participants (eg with respect to measurement systems) and the potential for stranded assets from investments in technologies that later become uneconomic.

We assume that the long run instrument will ensure that emitters face the international price of allowances as a cost of emitting; this would occur under both a charge and a trading mechanism (and regardless of the initial approach to allowance allocation). It would reward renewables by leading to an increase in the price of electricity and thus to an increase in revenues; in industrial sectors, a carbon price instrument would raise the costs of alternatives to renewables. The risks are that an interim instrument focussed solely on renewables would provide a separate revenue stream for new capacity and that the level of this revenue would be above that received by renewables under a long run instrument. Set against this, in the absence of both a price measure and renewables support policies, there is a risk of investment in the short run in new thermal capacity that might either be stranded in the future or receive too low a return on capital.

These issues are uncertain by nature, but in analysing individual instruments, we take account of these issues where possible.

2.1.3. Criteria for Analysis

The criteria used for analysis of the individual interventions are:

- Efficiency—does the instrument ensure that an optimal quantity of renewable energy is supplied or that a targeted quantity is supplied at least cost?

- Practicality—how difficult will the instrument be to implement, particularly the need for new legislation or for major changes to existing institutional and market arrangements?

- Spill-over effects—what are the impacts more widely on electricity and other end-use markets.

- Compatibility with an expected long run price instrument.

The individual instruments are analysed against these criteria. In addition, information is provided on cost incidence—who will bear the costs of the policy. Before discussing the individual instruments, firstly the concept of the overall objective is discussed. This sets the scene for the introduction of the individual instruments.

2.2. Renewable Objectives

There are different ways in which a renewable objective might be specified. The original National Energy Efficiency and Conservation Strategy (NEECS) introduced a target that, by 2012 there would be an increase in renewable energy supply to provide a further 30PJ of consumer energy relative to a 2001 base year. This is converted into an absolute target in PJs.

Alternative approaches include:

- No specific target, but an objective of an optimal quantity of renewables. This would be achieved by setting policy instruments in place that targeted the market failures, such as the cost of carbon and the need to improve energy security.

- No target but rather an objective of more renewables. This might be used alongside a price instrument for which there was some understanding of the maximum acceptable cost without a clear understanding or specification of the desired quantity outcome.

- An absolute amount in capacity terms, eg xMW of renewable generation plant. This can result in different quantities of renewables output (or input) as it will depend on load factors (utilisation rates) and efficiencies, where these apply. For example, wind turbines only operate when there is sufficient wind such that actual output is less than 50% of capacity or theoretically potential output. In contrast, geothermal plants might operate almost continuously.

- An absolute amount in energy terms. This is similar to the NEECS target, based on consumer energy. Targets might be specified as an input to consumer energy or primary energy. The main difference between these approaches is any efficiency loss in conversion.

- Percentage targets, either of total capacity or of energy consumption.

This report does not consider the advantages and disadvantages of these different specifications of objectives. However, the different instruments operate best with different types of objective, and these issues are noted in the discussion and analysis below.

2.3. Correcting Market Failures—Carbon Charges

A first place for any policy intervention is simply to correct the underlying market failure that justifies the intervention.

2.3.1. Description

Currently CO_2 and other greenhouse gas emissions are not priced in the market. They are an externality of thermal fuel combustion because of their global damage costs and, in the first Commitment Period under the Kyoto Protocol and (expectedly) beyond, they will result in a financial cost to New Zealand. The government has agreed to have allowances (parts of assigned amount) equal to its net emissions such that any emission requires either the purchase of an additional allowance or results in a lost opportunity to sell.[9] Because there is no mechanism currently to pass these costs on to emitters, it is an externality—a cost that is not expressed in the market. The theoretically ideal instrument (from an economic efficiency perspective) in the presence of externalities is a charge equal to the marginal damage cost or the marginal cost of the externality[10]—most easily represented as the international price of carbon. Ideally carbon emissions would be priced wherever they occur in the economy, either through a comprehensive carbon charge or a cap and trade scheme; a variation on this approach currently being considered is a charge that applies to emissions from large emitters, eg electricity generators and energy-intensive industry.

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[9] Initially the number of allowances has been allocated to New Zealand as its target, but this target is divisible and tradable such that the Protocol functions as an international price of allowances.

[10] Baumol WJ and Oates WE (1988) The theory of environmental policy. 2nd Ed. Cambridge.

The introduction of a price on CO_2 emissions changes the costs of generation of electricity and heat from thermal (and geothermal) sources. Table 5 above shows the impact of a CO_2 charge on the generation costs of thermal fuels. The range of costs for these plant types is still equal to the costs of renewable generation over some of its range under all carbon costs. However, the probability of new capacity being renewable is greatly increased. Other responses that can be incentivised include a shift from coal to gas, eg at Huntly.

To illustrate the effects further, Figure 7 pictures the current use of renewables as being the outcome of the costs of supply and demand for renewables. This is a slightly false picture but one that is useful for analysis. It is slightly false because, strictly speaking, there is not a demand for renewables separate from demand for energy more generally. However, for any new supply of renewable the quantity demanded at a given price is equivalent to the demand for energy.

Figure 7 Impacts of Carbon Price on Demand for Renewables

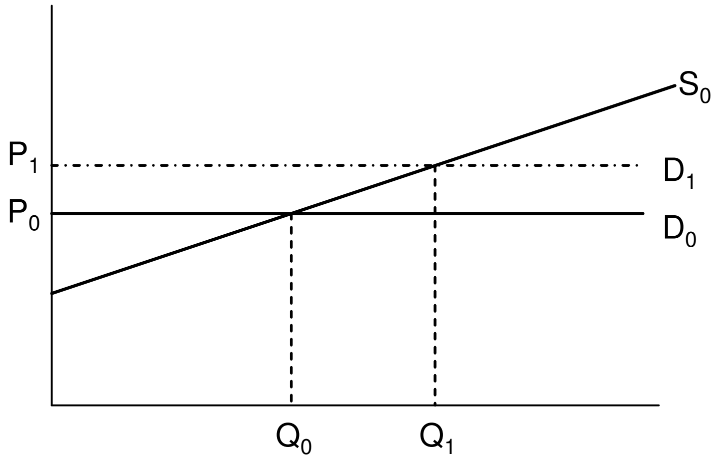
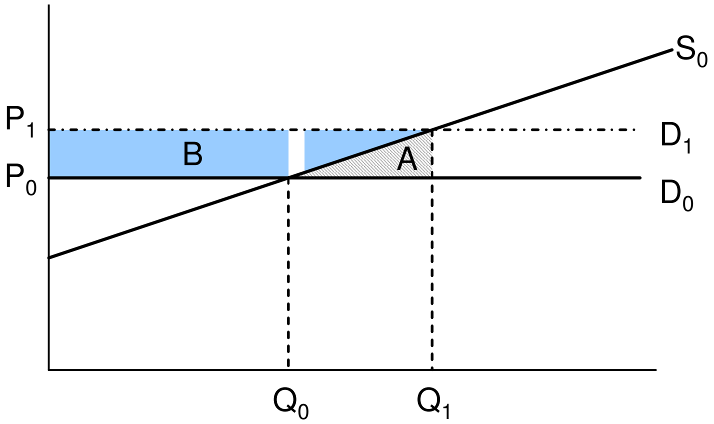


Figure 7 pictures an initial supply curve for renewables (S_0). Demand for renewables (D_0) is pictured as a horizontal line based on the price of alternative fuel supplies; the figure assumes that the market will consume all that can be produced at a given price—this is correct over a narrow output set, equivalent to the next unit of capacity, for example. An amount is supplied under market conditions equal to Q_0.

The impacts of a carbon price instrument are illustrated as a change in the demand curve; the new curve is pictured as D_1. This change occurs because the cost of thermal alternatives is raised. As a result the wholesale electricity price rises and renewables further up the supply cost curve are supplied to the market—an increase from Q_0 to Q_1. This would occur via new plant builds. Note, this is not an increase in total electricity supplied—this would decrease as a result of the carbon price because of the increased wholesale price. Rather it is an increase in the quantity of renewable energy supplied at the expense of supplies of thermal fuels.

The cost effects are explored in Figure 8. The shaded triangle (A) represents the increased costs to the nation for additional renewable energy supply. It represents the difference in costs between the costs of the alternative fuel and the costs of the renewables. In addition there is a surplus—the shaded area (B); it arises because the price of electricity is increased from the imposition of the carbon price and the resulting increased price provides increased revenues to all generators (this surplus will apply to thermal generators also). Under a carbon price instrument, this is a transfer from consumers to generators.

Figure 8 Impacts of Demand Measures



Additional entry of renewables may lead to some downward pressure on electricity prices because most renewables have zero or very low variable costs; this effectively pushes the short run supply cost curve outwards. However, these effects are taken into account by new entrants and while this limits the extent of new entry, the equilibrium will settle at a higher price because of these measures[11] and lead to some new entry.

For industrial uses of thermal fuels, the effects are similar. The equivalent impact on the wholesale price of electricity occurs in the form of a change to the marginal cost of supply of heat within a plant. Additional supplies of renewable energy occur where the changed cost of supply from thermal fuels increases above the costs of supply from renewables. The main difference, is that in heat plants there is some scope to use additional quantities of renewable fuels within existing plants, eg wood waste in existing solid fuel-fired plants,[12] plus, potentially, gasified wood waste in gas boilers. In theory these fuels could also be used in electricity plants, but it is more likely to occur closer to the fuel sources.

2.3.2. Efficiency

A charge on carbon, where the level is equal to an international price of emissions, or a cap and trade scheme linked to the international allowance market, provides incentives for shifts to renewables where the costs of doing so are less than or equal to the costs to New Zealand of continuing to use thermal generation in its stead. Such an instrument can be regarded as economically efficient by definition. It would be expected to result in the optimal amount of renewables entry consistent with meeting national commitments at least cost.

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[11] This is because thermal plant will continue to set the system marginal price.

[12] This is limited to boilers that have a grate, eg it cannot be used in pulverised fuel plants

A carbon price instrument does not differentiate between types of renewables but gives equal incentives to all. This is more efficient than instruments that differentiate between renewable types.

2.3.3. Practicality

A carbon charge is conceptually simple and requires only the estimate of emissions—this is already undertaken for inventory purposes and is straightforward for thermal fuel combustion. Currently alternatives in the form of a narrow-based charge on a limited number of sectors are being examined.

Cap and trade schemes that provide equivalent economic effects have the added difficulty of decisions over initial allocation of allowances. While neither affecting the economic incentives to reduce emissions, nor the impacts on prices, allocation choices affect the level of wealth transfers to participants. Gifts of allowances can reduce the cost impacts on industry (thus making introduction easier for the government) but they remove the potential for revenue generation from allowance sales that could be used to reduce distortionary taxes used otherwise for government revenue raising.

The introduction of economic instruments such as carbon charges will require new legislation.[13] Other details of the design of a simple carbon charge have been explored in detail by the government; alternative designs, including charges with thresholds, are being explored currently.

2.3.4. Spill-over Effects

The main spill-over effects of price instruments, in addition to the incentive for greater supplies of renewable energy, are on the prices of electricity. Prices will rise reflecting the price of carbon and the carbon intensity of the marginal generation fuels. The result is that the wholesale price of electricity reflects the marginal costs of supply, including the costs of carbon. This is an efficient outcome.

The effect in the electricity market is also that the price of electricity continues to reflect the long run marginal costs of supply (LRMC). The wholesale price rises to the level that leads to renewables entering, because they can recover their full capital and operating costs at those prices. Price equal to LRMC is regarded as an efficient market outcome as it provides the right long run signal to users of electricity, particularly with respect to new investment in electricity-using plants or equipment.

The efficient price of electricity is equal to LRMC based on the costs of new entry, including a price on carbon.

In industrial heat use, the impacts include changes in supply costs and, in turn, the costs of production. In some instances this will lead to changes in output prices, although this depends on whether prices are set in the domestic market or internationally.

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[13] Covec (2005) Economic Instruments for the Environment. Environment Waikato Technical Report 2006/23 (www.ew.govt.nz/publications/technicalreports/documents/tr06-23.pdf)

2.3.5. Cost Incidence

The costs of the instrument are passed on in final prices to consumers. The extent to which this occurs depends on the competitiveness of the sector. If fully competitive, the price will be passed on completely by marginal generators. However, in less than fully competitive markets where prices are above the marginal costs of supply, some of the costs of the charge will be absorbed. In industrial sectors costs will be passed on in competitive markets and where products are sold in domestic markets. Where the price of outputs is set by international commodity prices, eg wood pulp, costs will be absorbed (or production will be curtailed).

2.3.6. Transition to a Long Run Measure

A carbon charge is an example of a possible long run measure, although a tradable allowance (cap and trade) system is more likely because of its consistency with the Kyoto Protocol architecture and the growing international adoption of this approach. A carbon charge would have very similar effects economically and in the short run may be a simpler way to introduce a price on emissions that would ensure those responsible for emissions started taking these costs into account. The introduction of a price on emitting, even at a low initial level, would be expected to lead to greater focus on future price trends. This helps to reduce the likelihood of stranded assets. The issues raised above in evaluating the impacts of a carbon charge, including the effects on electricity prices, would apply also to a cap and trade system if introduced in the short run.

In practical terms, the measurement requirements of a charge and a trading system would be very similar also. There are options in terms of the liable party for a charge or allowance trading obligation, and specifically whether (from an energy emissions perspective) it is placed upstream on introducers of carbon to the economy (coal mines, oil importers, gas extractors) or downstream on emitters (those combusting fuels). Either can be used, although in practice, trading has tended to focus on emitters rather than upstream introducers, partly because of the scope for increased market liquidity from downstream responsibility.[14] If a downstream trading system is the long run instrument, this can limit the learning benefits of an interim charge instrument placed upstream.

2.4. Correcting Market Failures—Capacity Markets

2.4.1. Description

Examining a full set of options for achieving increased energy security is beyond the scope of this report. However, the focus is on whether instruments that might be used to address security of supply would provide incentives for greater renewables entry. The focus is exclusively on electricity supply because the grounds for market failure, if they exist, relate to the separation of supply from consumption: amongst other things, there is limited demand-side bidding in the electricity market in a way that enables firms or individuals to express their unwillingness to be short of supply. In contrast, for other

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[14] Arguments on grounds of liquidity are reduced when the trading system interacts with international markets

uses of renewables (industrial, residential) the supplier is often the consumer, ie generally heat demand is met by on-site production whereby the firm is fully exposed to the costs of any shortfall.

The main outcome of limited demand side participation in electricity markets is that there is potentially too little capacity and electricity consumers are exposed to risks of supply shortfalls, especially in dry years. Policy options would include capacity markets, direct contracting for capacity and regulated reserve margins. The question for analysis here is thus whether an instrument that was designed simply to encourage more capacity would also deliver renewable capacity. If so, there would be limited need for specific renewables policies to address this market failure.

An instrument to address security of supply is envisaged initially as a capacity market. This would introduce a requirement on someone (eg electricity retailers) to purchase a specified amount of capacity over and above the energy purchased. This capacity would be available to supply, albeit not called to supply. Plants would bid either to supply energy (electricity) or available capacity and could be paid, in any time period, in one of these markets.

Renewable electricity is unlikely to bid into a capacity market for two reasons:

- it is expected that the price in the capacity market would be lower than in the energy market (otherwise all plants would sit as capacity rather than producing energy). Because renewables have, in general, zero costs of generation they are better bidding in the energy market. In contrast, some thermal plants at least may be better bidding in a capacity market as, although the revenues may be lower, the costs will be lower also—they avoid fuel costs;

- renewable generation, particularly wind, tends to be less predictable and cannot reliably offer capacity—although notably this is not the case for geothermal.

The incentives for new renewables will thus be entirely based on the effects of a capacity market on the wholesale electricity price. And simply, because there will be more capacity, the electricity price would be expected to be lower or at most the same as before the capacity market. The capacity market might be met by new entrants or existing entrants that can make greater returns in the new market. New entrants would thus bid in the electricity market if they were more efficient (had lower variable costs of supply) than existing participants.

Introduction of a pure capacity market would thus be expected to lead to a slightly lower wholesale electricity price (or to no change) and subsequently to a reduced incentive for new renewables or, at best (from a renewables perspective), to no change. Alternative formulations of a capacity requirement, eg a capacity obligation could have the same effect because they introduce a separate market in which capacity receives a return. Pure capacity instruments are not considered further here. However, it is useful to note that they can have adverse impacts on renewables supply.

2.5. Changing Costs of Alternatives—Carbon/Energy Taxes

2.5.1. Description

The carbon charge discussed above can be used to provide additional incentives for renewables by increasing the charge level above the rate it would be based on the international price of carbon. However, this leads to inefficient levels of response, including the extent of fuel switching from coal to gas. A variant on a carbon charge is a charge on thermal energy; it would not differentiate between coal and gas, but merely between renewables and non-renewables; it would avoid a charge on geothermal energy. The effects would be different depending on whether it is defined on an input (GJ of fuel burnt) or output (MWh of electric or heat output). On an input basis, efficient CCGT plants would be rewarded over open cycle gas and coal plants, so it would tend to favour gas; on an output basis the fuels would be treated the same.

The distortion effect is the same as for a carbon charge, in that the price of output from the alternative fuels needs to be raised to a level that is sufficiently high that renewable energy can compete and displace the thermal energy, and the effect is as shown in Figure 7 and Figure 8 above.

2.5.2. Efficiency

An energy charge is efficient to the extent that it does not differentiate amongst renewables in terms of which ones are incentivised, but it is less efficient in terms of the shift away from any basis on internalisation of external costs, such as the international price of carbon. However, it is no less efficient in this regard than any instrument that seeks simply to increase the quantity of renewables supplied.

The key issue which differentiates it from other instruments that incentivise more renewables is that it works on the demand side (the cost of alternatives) rather than the supply side (the costs of renewables). For electricity it has an impact on the wholesale price equal to the charge level and the thermal content of marginal generation, although this is affected by the level of new entry that results also. This is because the new entrants will push existing plants further to the margin. Prices will reflect the costs of entry (effectively LRMC) but based on a modified market price and a modified set of new entrants. Above we defined the optimal price as based on the cost of new entry including a carbon price; the relationship to that optimal price is lost under this instrument.

Unlike the carbon tax which has co-benefits in terms of a least cost reduction in CO_2 emissions there is no guarantee that such an effect will result from a thermal energy charge. The quantity of CO_2 reduced per additional unit of renewable energy produced will be lower if incentivised by an energy charge than by a carbon charge. This is because the new renewable energy will be no more likely to displace coal than gas.

2.5.3. Practicality

A thermal energy tax requires new legislation in the same way as a carbon tax; the requirements for measurement are the same.

2.5.4. Spill-over Effects

The spill-over effects of a charge on thermal energy are similar to the carbon charge. The charge will change the price of thermal fuels, the costs of production and the market price of outputs, unless this is set by firms that are not covered by the charge, particularly firms in other countries. This does not apply to electricity generation but does to some industrial products that have the potential to use heat generated from renewables.

2.5.5. Cost Incidence

As for a carbon charge, the incidence will be initially on fuel users and will be passed on to consumers depending on the degree of competitiveness of the industry and the extent to which domestic markets sets price.

2.5.6. Sectoral Applicability

The charge can apply to all users of thermal fuels in the same way as a carbon tax. This could include sales to industrial and residential customers.

2.5.7. Transition to a Long Run Measure

This measure has the same advantages as a carbon charge. Particularly important and useful is the introduction of an initial price on emissions that will lead to greater focus amongst industry on projecting future prices and taking this into account in investment decisions.

2.6. Changing Supply Costs—Capacity/Capital Subsidies

2.6.1. Description

There are a number of mechanisms that have been used in other countries to subsidise investments in renewables capacity. These include capacity auctions and specified payments for additional capacity. Subsidy equivalents can also be provided in the form of tax deductions or accelerated depreciation.

Capacity subsidies are relatively straightforward in conception, if not in implementation. Whether as a tax incentive or a direct payment to a firm, the government pays the firm enough (or more than enough) to ensure that new capacity is installed. Once installed, renewable capacity would be expected to operate in the market in an efficient way. Because of the very low variable costs of electricity generation using renewables, this will have an impact on market prices pushing lower cost plants to the margin in all time periods.

The amount of subsidy paid will depend on the competitiveness of bids to supply capacity (how many bidders) and the market expectations of future electricity prices. Given that some of that risk is in government hands, eg decisions on other instruments to tackle greenhouse gas emissions, government funding of some elements of capacity may be consistent with optimal risk-bearing.

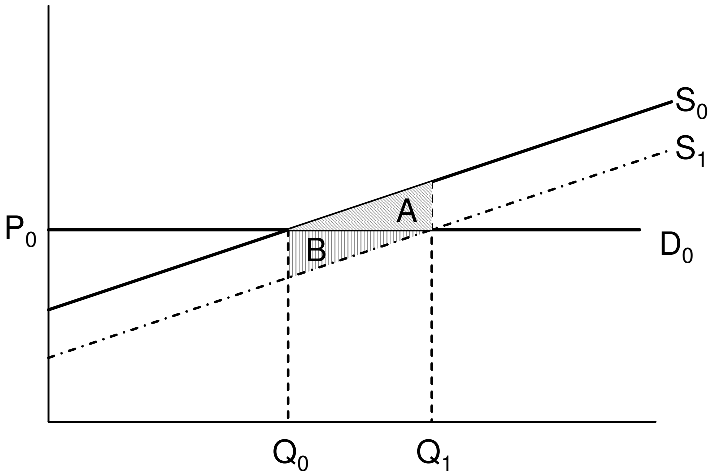
The main approaches are:

- Published quantities of subsidy that could be provided, eg $x/kW of capacity installed (this would include equivalent tax measures and reduced depreciation)—this risks not discovering lower bids (or smaller levels of tax incentive). It also has risks relating to the total amount has to be paid out if no limit is set on the total capacity that might be funded;

- Auctions —this has risks only if the government pre-announces that it will purchase a given amount. If it retains all options it can choose whether to and how much to purchase solely on the basis of price offered.

Figure 9 shows the cost effects. The impact of the measure is a reduced supply cost, which is produced as a new supply curve (S_1), although there are a number of possible shapes. The cost to the nation for achieving the same quantity of renewables entry as depicted in Figure 8 is exactly the same; it is the additional costs of the renewables supply over and above the costs of supply of alternative (thermal) energy. It is depicted by Area A.

Figure 9 Impacts of Supply Cost Measures



There are different ways in which the subsidy can be paid to achieve these outcomes that result in different levels of subsidy paid. The smallest amount of subsidy is exactly equal to the size of triangle A and some instruments might achieve that, for example a pay-as-you bid auction. This would pay just enough to generators to ensure that they invested in the new renewable technology. It would result in a supply curve (from the generators' perspective) that was the same as S_0 up to Q_0 and was then horizontal to Q_1. Other instruments will pay an equal subsidy to each investor in new capacity based on the quantity (MW) of renewable supply. This can mean that the subsidy required is equal in size to the sum of areas (A) and (B) and a supply curve that tracks S_1 between Q_0 and Q_1.

The amount required can be higher still if the amounts paid are targeted at specific technologies. This is an approach used in some other countries where, for example, subsidies were paid in tranches for individual technology types. This increases the total costs because the supplies provided are not necessarily in order of cost.

2.6.2. Revenue Source

An issue that is raised by all instruments that are based on use of a subsidy payment is the source of the revenue.

As discussed above, there is no difference in the resource costs of obtaining a given increase in renewables through different policy measures; it is the additional supply cost (Area A above). However the resource cost is only one of two main cost components, the other being the opportunity cost of the funds used to procure additional renewable supply. Costs could fall on the government, industry (eg electricity generators) or consumers.

While any of these groups could be made liable, the economic impact only depends on whether or not the government funds the policy directly. This is because any obligations placed within the market context (eg via a carbon or an energy tax or through an obligation), whether on consumers or electricity companies, will have the same economic impact.[15]

The impact of obliging the industry to fund a policy is that the burden will be shared between firms and consumers. To the extent that the supply of electricity is less than fully competitive, firms will bear a relatively high share of that burden.

If the government funds the policy via subsidy, it will ultimately obtain the funds through taxation. To a first approximation, taxpayers and electricity consumers are the same set of persons. So the choice can be framed as being between allocating all the burden to final demand via taxation, or sharing it with the supply side of the electricity industry. The argument could be taken in either direction.

- On the one hand, the main reason for the policy is to change behaviour on the supply side of the electricity market (towards more renewables) and the need for the policy is driven by existing electricity market behaviour (too little investment in renewables, as defined by the government). This would suggest that the industry (and consumers) should bear the costs;

- On the other hand, to the extent that the policies go beyond internalising external costs (as a carbon tax would), the justification of the policy relates to benefits that

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[15] Formally, this is because the incidence of a sales tax (ie which parties bear the burden) is independent of which party (consumer or producer) is liable for it.

are shared by society as a whole and the burden might more appropriately be borne by taxpayers.

2.6.3. Efficiency

Subsidies on renewable capacity are unlikely to be used to pursue an efficient quantity of renewables—this would be achieved via the establishment of the target that is pursued by the measure. There are three issues of concern from an efficiency perspective:

- whether the instrument can operate to achieve new investment in capacity at least cost;
- the revenue raising effects; and
- the effects on output (eg electricity) prices.

The ability to achieve increases in capacity at least cost depend on the approach used and crucially on whether the subsidies are paid out to all renewables, regardless of type or if they are specifically targeted at wind, hydro, geothermal etc. Providing equal opportunity to all types is the least cost approach.

Also, the instrument can be designed in a way that either pays just what is required to achieve more renewable entry or rewards all renewables the same amount, regardless of what is required to achieve entry. At one level this does not matter—the subsidy is a transfer from the government to a generator and it does not matter if an excess is transferred because it does not change either the level of entry or the subsequent bidding behaviour in the market. However, it matters if there is a cost to raising revenues for the subsidy because of the distortionary effects of taxation. Where there is, minimising the subsidy amount is preferable.

The third issue relates to the effects on electricity prices. Despite the fact that a capacity subsidy does not change the input (or output) prices directly, it can change total system prices. Any measures that increase the total renewables capacity in the electricity market will shift the supply curve for thermal fuels (those with variable costs greater than zero or thereabouts) to the right, thus reducing marginal electricity prices. This is not an inefficient outcome in the short run, in that resources will not be used in a market that values them at less than their costs of supply. However, there are risks for firms that have invested on the basis of expectations of electricity costs being set in a market without intervention, that fixed costs will not be recovered. In addition, suppressing the wholesale price will limit the incentive to install any new capacity including renewables and may set in place an ongoing requirement for intervention to achieve new entry or a period of readjustment that might involve price instability.

The addition of renewables to the existing system on the basis of subsidies, at capacity levels greater than the market would deliver, is likely to result in increased reserve margins (as some plant is no longer required) and marginal plant status falling to plants with lower variable costs of supply. In such an outcome, system prices are likely to be maintained at less than long run marginal costs of supply. In the short run the price signals are correct—generation assets will be used efficiently from least to highest cost—but because of the downward impacts on electricity price the long run signal to investment in electricity-using equipment and industries is inefficient, ie too much electricity is used if it is priced at below LRMC.

There will be some demand response to such a downward shift in electricity price which may limit the electricity price drop and negate some of the environmental benefit (the demand growth is met by thermals that otherwise would be displaced). However, this response will not take up all of the effect and prices will equilibrate at a lower level. Eventually prices will need to rise again in order to achieve new entry without policy support.

2.6.4. Practicality

A capacity subsidy would be relatively simple to introduce and may not require new legislation. The simplest approach would be a capacity auction. An auction system would require the government to announce a desire for new renewable capacity and a willingness to provide funding towards it. Firms would be invited to bid at a specific time and the government could select bids based on price and quantity.

There are design issues that would be required relating to the auction design, and a large literature on design options that might be considered in choosing a design.

Alternative approaches would include published subsidy values, eg $x per MW up to a maximum capacity (or $). This requires more detailed analysis of costs of new technologies and the likely bids at different levels, or simply an understanding of the government's willingness to pay based on some other criterion, eg $/tonne of CO_2 reduced.

2.6.5. Spill-over Effects

As discussed above, this measure does not directly affect electricity prices, but because it shifts the supply curve to the right, will result in lower electricity prices and potentially increased electricity demand.

2.6.6. Cost Incidence

The costs of the measure will fall on tax payers as additional requirements for tax raising or will result in some reduction in government expenditure elsewhere. Existing electricity generators will see a reduction in revenues from lower electricity prices.

2.6.7. Sectoral Applicability

This approach can be used to encourage renewables use by the household sector, eg in the form of subsidised installations of solar hot water heating systems or small-scale wind generators. However, this sector would be difficult to include directly in an auction-based system, although bidders could include manufacturers of this equipment, confident that they could sell at a subsidised price.

It could apply to industrial installations of new heat or electric plant, but it does not provide incentives for additional use of renewable fuel in existing plants, eg through gasification of wood waste.

2.6.8. Transition to a Long Run Measure

Capital subsidies can be compatible with a long run measure. They provide payments that ensure that investments are made in new capacity, although as discussed above, are likely to lead to a reduction in electricity prices. Under long run price measures it would be expected that electricity prices would rise, eg reflecting an emissions price expressed in the market. This would result in greater returns to investment in renewable capacity built in response to a capital subsidy. It would not be expected to lead to regrets in investment. In contrast, without such an instrument, investment in thermal capacity is more likely for which there may be regrets.

On other issues, eg measurement and capacity building, capacity payments provide no additional benefits.

2.7. Introducing New Markets—Capacity Obligations

Obligations to supply renewables come in a variety of forms including those that target capacity (this section) and generation (see Section 2.8.4). In general they are characterised as an obligation on an industry player to ensure that a targeted quantity of renewable generation (electricity or heat) capacity or level of generation from renewables is achieved.

2.7.1. US Renewable Portfolio Standards

The US system of Renewable Portfolio Standards (RPSs) sets minimum targets for electric utilities to generate from renewable sources or to hold a certain percentage of capacity as renewables by a given date. Twenty US States and the District of Columbia have introduced RPSs (Figure 10).[16]

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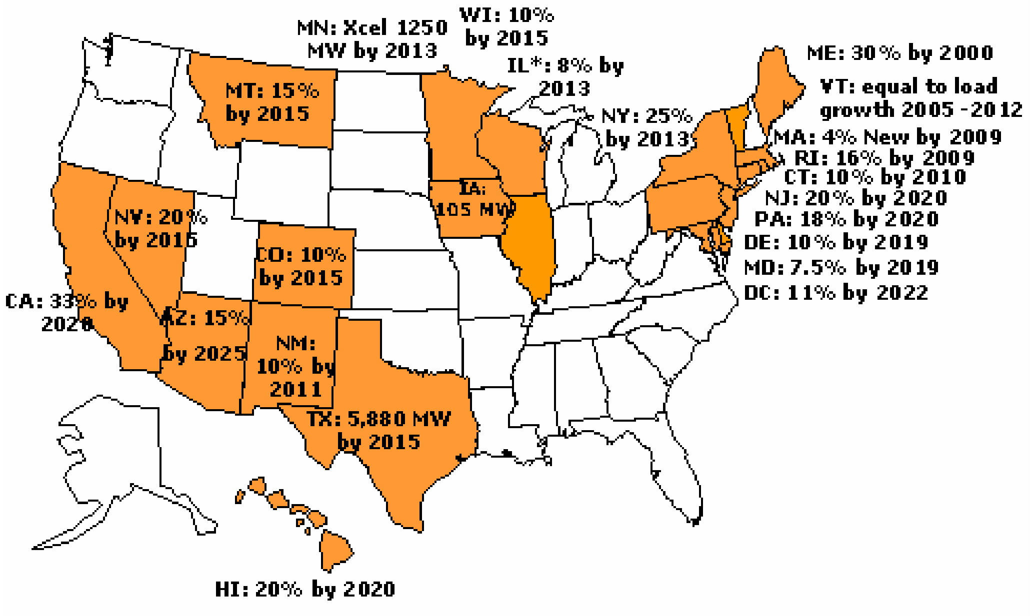
[16] An additional two states, Illinois and Vermont, have set voluntary goals for adopting renewable energy instead of portfolio standards with binding targets

Figure 10 RPS Systems in the US



Source: Pew Centre (http://www.pewclimate.org/what_s_being_done/in_the_states/rps.cfm)

These obligations are implemented in a wide variety of forms.

- In New York, the regulated utilities collect a surcharge on customer bills and transfer those funds to the New York State Energy Research and Development Authority (NYSERDA) that administers the RPS programme. NYSERDA provides incentives, based on output, to renewable energy producers that sell and deliver their energy into the New York wholesale market—this is an output payment, similar to a feed-in tariff (see below). In addition, funding is provided to customers to install distributed generation.[17]

- In California, payments are made to eligible renewable energy resources to cover above-market costs of renewable energy. Again, the outcome is similar to a feed-in tariff approach[18]

- In Texas, each electricity retailer is required to obtain renewable energy capacity based on the provider's market share of electricity sales times the renewable capacity goal. Thus a retailer with 10% of electricity sales in 2009 would be required to obtain 200 megawatts of renewable energy capacity.[19] The renewable capacity required by the electricity sellers can be provided directly or through the Renewable Energy Credit (REC) market. This market enables renewable energy producers to sell energy and renewable energy credits separately. It also allows

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[17] New York State Public Service Commission (2006) Retail Renewable Portfolio Standard. www.dps.state.ny.us/03e0188.htm

[18] California Energy Commission. http://www.energy.ca.gov/portfolio/index.html

[19] Pew Center on Global Climate Change State and Local Net Greenhouse Gas Emissions Reduction Programs. Texas. http://www.pewclimate.org/states.cfm?ID=20

retailers to buy credits instead of owning or contracting for electricity from renewable sources.

The US systems have widely different means for achieving the obligation and in many instances individual utilities have introduced measures to achieve their obligations that are similar to other policy instruments examined in this report.

In this section we examine the potential use in New Zealand of capacity obligations. We consider generation obligations under Section 2.8 below.

2.7.2. Description

An obligation might be introduced for either total or new capacity within a given time period to equal a targeted amount. For example, each generator could be obligated to hold renewable capacity equal to a specified percentage of its total, or a specified total in MW.

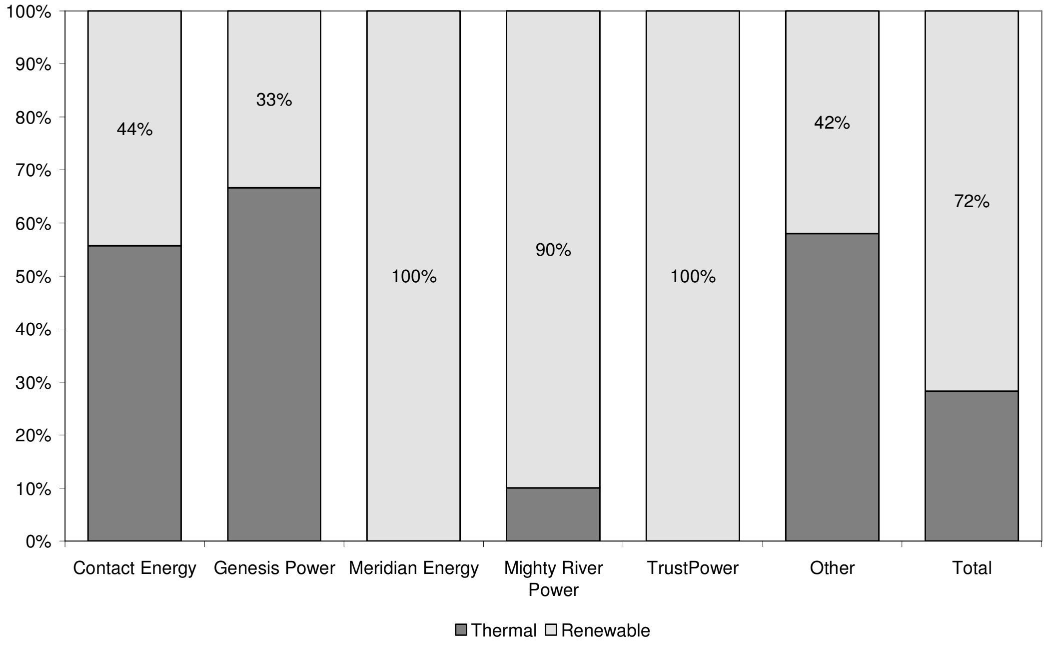
Figure 11 shows the existing split of renewable and thermal capacity amongst the five main generating companies, other small operators and in total; the percentage contribution amongst the companies varies greatly. Clearly an equal physical obligation on generators would introduce considerable difficulties for some generators if the obligation applied to total (as opposed to new) capacity. Achieving a uniform percentage would require considerable sales of plants, with high transaction costs and with no real benefit.

However the system can also operate through obligations to hold certificates that verify the existence of capacity. For existing and new capacity, this would simply be a verification that a plant was of a specified capacity representing its maximum potential output. The obligation to hold such certificates could rest with anyone; the certificates become tradable commodities with the obligated party purchasing them from the generators.

Key design issues will be:

- the choice of obligated party—which could be generators, retailers or distribution (lines) companies;
- the nature of the obligation and particularly whether it is changes with activity; and
- whether to target all capacity or only new capacity.

Figure 11 Renewable Percentage of Current Capacity



Source: MED (2006) Energy Data File January 2006

Obligated Party

The level in the industry at which the obligation is introduced need not matter, as the cost impact would be expected to be passed upwards or downwards as appropriate, eg from generator to retailer (especially where this is the same entity). The chief concern is likely to be over market power. There is potential for market power where a single or small number of firms dominate the supply of certificates that verify fulfilment of the obligation, and this is possible because of the lumpiness of investments. For example, if there is a requirement for 100MW of new capacity in a year and a single firm invests in that 100MW, it holds power in that market to set price. Market power is reduced if the obligations are spread over several years or if banking or borrowing of certificates is allowed under the rules.

Nature of the Obligation

The obligation can differ in terms of how widely it is spread and how it is specified.

Say there was a requirement for an additional 100MW per year of renewable capacity. This might cost approximately $180 million in capital costs,[20] but the cost of the obligation would be the amount required to ensure this level of investment. This would be less than the full amount because the investor in the plant would receive an income from sales of electricity. It might be a lower sum of say $20 million. The obligation to achieve this might be:

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[20] Based on $1800/kW for new wind turbines

- Spread across all sales of electricity and be defined by the quantity of generation or sales —the price in every period would be expected to rise by $20M divided by, say 37,000GWh of sales, ie $0.54/MWh;

- Spread across all thermal sales—$20M divided by, say 10,000 GWh, ie $2.00/MWh for those plants.

The impacts on electricity price would depend on the impacts on the plants that are on the margin setting price. Using the above examples, it would either result in a $0.54/MWh or a $2.00/MWh increase in price, offset by the fact that the new generation would push lower cost generators onto the margin. Where the price effect was higher, it would provide increased revenues and profits to existing non-thermal generators.

The above example has the level of obligation related to total sales, ie MWh; it could be similarly linked to sales of thermal energy (as shown) or output of greenhouse gas emissions.[21] Each approach would have different effects depending on the extent to which it represented all electricity sales. The obligation could relate to sales in the given year or in a previous year.

An alternative approach would be to relate the obligation to capacity. For example, the obligation to install an additional 100MW of renewable capacity would be allocated to firms on a percentage basis on the basis of existing capacity levels (see Table 7 for electricity capacity owners). Thus for an aggregate 100MW obligation, a 26MW obligation would be allocated to Contact Energy, and so on.

This would provide no marginal effect and therefore the impact on electricity price would be solely that of the shift in supply curve as lower cost plants were on the margin setting price. Electricity prices would be expected to fall.

Table 7 Current Plant Owners—Electricity Generation

Owner	Capacity (MW)	% of Total
Contact Energy	2225	26%
Genesis Power	1501	18%
Meridian Energy	2584	31%
Mighty River Power	1247	15%
TrustPower	452	5%
Other	433	5%
Total	8442	100%

Source: MED (2006) Energy Data File January 2006

To specify it in a way that varied with carbon output could restrict the obligated party to generators (of electricity and heat).

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[21] Establishing an obligation on retailers or lines companies that related to carbon content would require a tracking of electrons or some contractual relationship with generators that related to individual plants.

New or All Capacity

An obligation can apply to new or all renewable capacity. For example, the obligation could be for there to be 6500MW of renewable capacity in 2010. This would lead to payments being made to existing capacity holders of the same amount as new entrants. It is in some ways equitable in that it does not differentiate between companies that invested just before the policy was introduced, but clearly provides no marginal signal to these firms and would lead to very large transfers, in a system that already provides considerable surpluses to owners of existing renewables. If the equity outcome is desired, a limit could be specified, eg all capacity built after some historical year.

There is a potential argument for extending it to all capacity on the basis of improvements in market liquidity—it ensures more sellers in the market, but this does not seem a strong argument in contrast to the large potential transfers.

An alternative specification is for the average percentage of new generation to have to meet a target. This is easiest to achieve when there is considerable growth in demand but becomes difficult if growth rates are low and plants are lumpy—thermal plants, in particular are large, such that if a company was to build a new thermal plant it might be difficult to achieve targets. For example, if the target was 75% of all new capacity, thus ensuring that the overall percentage did not fall over time, this would require a large additional investment in renewable generation to accompany it. This is particularly a problem if a thermal plant is built early in the period of implementation of the policy but reduces in difficulties if the reconciliation period is long or if banking or borrowing is allowed.

2.7.3. Efficiency

A capacity obligation can introduce relatively efficient and effective incentives for supporting new capacity. In practice it functions in the same way as a capacity subsidy funded by the government. In a similar way, it provides incentives for least cost introduction of renewables. There are a number of advantages over the government subsidy.

Firstly, the market can define the level of support that is required to obtain additional capacity.

Secondly, the negative aspects of a government subsidy (price reductions in output markets) can be mitigated through the specification of the obligation, and specifically ensuring that the obligation increases at the margin with changes in activity. This might include CO_2 (GHG) emissions, output of thermal power or total sales of energy. This ensures that there is upward pressure on electricity prices.

Set against these possible advantages, there is no certainty that the final electricity price will by optimal, ie the cost of new entry including a carbon price. We are starting from the perspective that the current market results in a price that trends towards LRMC but excluding a carbon price; thus an increase will move towards the optimal price. But a capacity obligation, as specified here, might result in too high a price.

In addition, there is some risk, in a small market, that producers of certificates will hold considerable market power. For example, if early in the introduction of the obligation a single firm established a 1000 MW plant (eg a very large wind farm), it could completely dominate the certificate market and set prices at very high levels. These risks can be minimised through buy-out mechanisms such as used in the UK Renewables Obligation (see below). Here a cap is set on the price of a certificate in the form of a payment that an obligated party can make rather than purchase a certificate. This would seem to be a sensible component of any New Zealand system, given the level of potential market power.

2.7.4. Practicality

Establishing a capacity obligation requires the definition of a new legal commodity—a renewable capacity certificate. This would require new legislation. The necessary components of the system include:

- An obligation or target;
- An obligated party;
- A defined means of compliance and demonstrating compliance;
- Penalty regimes.

2.7.5. Spill-over Effects

The impacts on electricity prices have been discussed at some length above. The capacity obligation can be specified either on the basis of activity (MWh) and will result in an increase in electricity prices, or on the basis of capacity and there will be a reduction in price. Whereas we know that the reduction in price is away from the optimal price, it is not clear whether the upward shift in price will be too much.

2.7.6. Cost Incidence

The obligation can be specified in different ways so that costs fall on different parties. If the obligation is specified on a MWh basis in the electricity market, costs would be expected to be passed on such that the initial specification does not matter. However, if specified in capacity terms, the costs would be expected to be absorbed by generators.

2.7.7. Sectoral Applicability

Capacity obligations can be specified for industrial firms in the same way as for electricity companies, eg a requirement to ensure a given level of (new) capacity that changes with MWh of heat and/or electric output. This is more difficult in practice if a sector is static or in decline, eg if there are few expectations of investments in new capacity in the forest processing sector. Alternatively these plants or firms can be included within a system that applies to electricity generators also. Amongst other things, this adds to the liquidity of the market.

There are some complications here however. Firstly, plants that burn renewable fuels, eg wood waste or gasified wood waste, might also burn thermal fuels. There is a question over whether the payment made for establishment of capacity would require that the plant was somehow fuel-dedicated (and this might require several years of monitoring). In addition, some of the opportunities for expanding the use of renewables in industrial sectors is in existing plants, eg wood gasification to burn in an existing gas boiler.

The first issue is not easily resolved. Most simply the obligation system would work where the definition of renewable plant is unambiguous. This complexity might auger against inclusion of these industries. The second issue suggests that a generation obligation would be a more appropriate specification for industry participants.

Residential capacity might be included in the capacity obligation system also. For example, installers of solar hot water heaters might produce capacity certificates that could be sold into the certificate market. This does not require that households take on obligations, which would be impractical.

2.7.8. Transition to a Long Run Measure

Capacity obligations can be compatible with a long run measure in the same way as capital subsidies. The main risk is that the obligation is set in a way that results in a higher electricity price than would result from the long run measure. A capacity obligation has two effects—it provides payments for capacity and it results in an increase in electricity prices. If investments in new capacity are made on the basis of an expected electricity price path that includes the effects of a capacity obligation, the risk is that the price path may be lower under a longer run instrument. This can result in inadequate returns to capital.

In practice, once built, the new capacity will still be utilised, so in that sense there is no risk of stranded assets. There is some risk to firms that might result in firm closure (and the sale of the assets), although this is most likely if the providers of new capacity were small firms that only had assets built in response to this incentive. This is unlikely. However, ideally the level of the capacity obligation would be set in a way that resulted in a similar impact on electricity prices to that resulting from a CO_2 price measure.

On other issues, eg measurement and capacity building, capacity obligations provide no benefits.

2.8. Introducing New Markets—Generation Obligations

2.8.1. Description

A generation obligation would function in a similar way to a capacity obligation but the requirement is specified as units of output. There are a number of international examples.

UK Renewables Obligation

The UK Renewables Obligation requires electricity suppliers to supply 10% of their output from approved renewable sources in 2010, with lower annual targets in years prior to this date.[22] Proof of compliance is via holdings of Renewables Obligation Certificates (ROCs), which are allocated to renewable generators for every kWh generated from an approved source.

There are unique elements of this trading programme:

- it introduces a price cap on ROCs. Suppliers have the option of purchasing ROCs or paying a buy-out price of 3p/kWh. This is introduced because the government is not willing to meet the renewables target at any cost;

- the revenues from the buy-out mechanism are returned to suppliers in proportion to their holdings of ROCs. This means that, while there is an overall under-supply, purchases of ROCs are worth more than the 3p/kWh avoided cost of the buy-out because the value includes, in addition, the returned revenue from the buy-out.

The use of a buy-out is equivalent to a hybrid tradable permit/emissions tax system. Normally, in contrast to taxes that provide price certainty, but emissions uncertainty, tradable permits provide emissions certainty but price uncertainty. Such a hybrid, in which firms have an option of purchasing allowances or paying a charge, provides certainty in achieving an objective only if the cost is below a certain amount.

Texas Renewable Energy Credit (REC) Market

As noted above, in Texas there is a requirement on electricity retailers to hold Renewable Energy Credit (REC) certificates to cover a specified percentage of their sales. RECs are earned for each MWh produced by renewable energy generators started after September 1, 1999. They are also earned for all renewable generation less than 2 megawatts and for metered "generation offset" technologies (eg solar water heating and geothermal heat pumps). The REC market is administered by ERCOT, the Texas electric grid operator. RECs are issued quarterly, based on meter readings. RECs can be used in the year created and can be banked for two years, after which they expire.

Application in New Zealand

Implementation in New Zealand would be similar to the description of the capacity obligation above. Obligated firms would be required to purchase certificates demonstrating that generation (of renewable electricity or heat) had occurred in a given time period. These certificates would be produced by the renewable generators and sold to the obligated parties.

The implications for obligated parties and spill-over effects into electricity markets are very similar to those of capacity obligations. And the same issues surround the question of whether generation from existing or only from new capacity is counted. The international regimes have specified the obligation as a percentage of total sales and this

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[22] Department of Trade and Industry (2001), 'New and Renewable Energy: Prospects for the 21st Century. The Renewables Obligation Statutory Consultation.'

is one approach that could be used here. However, the specification could also be in absolute terms, eg an obligation to ensure 30,000 GWh of renewables generation.

The key difference is the financial incentive that is provided to the investors in new capacity. The use of a generation obligation provides renewable generators with an additional revenue stream each year based on output, and this provides a means to obtain a higher rate of return than without the obligation. However, there is considerable future market uncertainty over the level of this additional payment. Uncertainties include:

- because it is a new market and there is little history to learn from, levels of payment will not be clear and it may take some time to settle and for price expectations to be defined;

- there is some regulatory uncertainty because the certificate market might be changed in the future;

- there is technological uncertainty because new developments may make renewable entrants economic in the absence of a support market such that certificate prices drop to very low levels.

It is likely that the expectations of prices in the certificate market will be very heavily discounted, particularly in early years. This might in turn lead to limited response in terms of additional capacity and therefore relatively high certificate prices. Commenting on the bankability of projects under the UK Renewables Obligation, the Renewable Energy and Energy Efficiency Partnership (REEP) commented that an effective policy framework must be:[23]

- **Loud**—the signal to the market, through incentive structures or other means, needs to be 'loud' and clear to attract capital into the sector;

- **Long**—rules and incentives need to be stable and sustained for a duration that reflects the financing horizons of the projects;

- **Legal**—a legally-established regulatory framework based around binding targets or implementation mechanisms is needed to provide the basis for long-life capital-intensive investments.

For investors there is a risk that payments will only continue to be made while renewable generation is scarce, ie there is less capacity than require to meet obligations. Once there is sufficient capacity, renewable generators are willing to generate at practically a zero payment, which means there is a risk of generation payments falling to very low levels (or zero). Because of this, secondary markets are likely to develop in obligation certificate futures that guarantee new investors an additional revenue stream. This might begin to turn a generation obligation effectively into a capacity obligation.

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[23] REEP Financial Sector: Statement On Renewable Energy (available at www.reeep.org)

2.8.2. Efficiency

A generation obligation does not differentiate between types of renewables and thus can provide incentives for least cost entry. The chief efficiency concerns are over the market certainty and the impacts on electricity price.

The issue of certainty in the certificate market is discussed above. Because there are many ways to fulfil the obligation and no history with the instrument, there will be a learning period during which uncertainty will be high and there will be some high discounting of the expected future price of the certificates. This can lead to early price volatility or to the development of a secondary or contract market. If a comprehensive secondary market does not develop, the instrument is likely to take time to bed down and it means that the cost falling on obligated parties to achieve a given level of entry may be higher than using a capacity obligation.

The impact on the efficient level of electricity price is as discussed above for capacity markets. It will depend on whether the obligation is specified on the basis of capacity, or as is more likely, on a generation basis. On a capacity basis, there will be a reduction in electricity price. On a generation basis, price will rise and the level of rise will not necessarily bear any relationship to an efficient price equal to the marginal costs of entry including a carbon price.

2.8.3. Practicality

As for the capacity obligation, establishing a renewable generation obligation requires the definition of a new legal commodity—a renewable generation certificate. This would require new legislation. The necessary components of the system include:

- An obligation or target;
- An obligated party;
- A defined means of compliance and demonstrating compliance;
- Penalty regimes.

2.8.4. Spill-over Effects

As for the capacity obligation, the generation obligation can be specified either on the basis of activity (MWh) and will result in an increase in electricity prices, or on the basis of capacity (the level of capacity determines how many generation certificates you need to purchase) and there will be a reduction in price.

2.8.5. Cost Incidence

The obligation can be specified in different ways so that costs fall on different parties. If the obligation is specified on a MWh basis in the electricity market, costs would be expected to be passed on such that the initial specification does not matter. However, if specified in capacity terms, the costs would be expected to be absorbed by generators.

2.8.6. Sectoral Applicability

Generation obligations can be specified for industrial firms in the same way as for electricity companies, eg on the basis of MWh of heat and/or electric output. Most simply this would be implemented by including these firms in an obligation system that applies to electricity generators also. Amongst other things, this adds to the liquidity of the market. As noted under capacity obligations, a system based on generation better enables participation by these firms because there is scope for using renewable fuels in existing plants and new capacity could be dual-fuel also.

Residential capacity would be more difficult to include because of the need to measure output. It is likely that this is too difficult to achieve. To do so would need a simplifying approach to define levels of output, eg based on capacity. In addition, households would then need to participate in the market by selling generation certificates. This appears impractical or to have very high transaction costs.

2.8.7. Transition to a Long Run Measure

Generation obligations are less compatible with a long run measure than measures focussed on capital or capacity payments, although the extent of this compatibility depends on the contractual response to the measure. A generation obligation will result in a string of expected future payments to an investor in new renewable capacity. This is set, via the market, at a level sufficient to ensure that the capacity is invested in. The payments may be given greater certainty via contractual arrangements between the obligated party and the renewables supplier as a future guaranteed level of payments. In the absence of such a contractual response, switching to a long run measure that simply involves a price on carbon may lead to a different level of return, ie one based on a higher electricity price but without a separate revenue stream from obligation certificates. This can result in inadequate returns to capital.

As noted for capacity obligations, once built, the new capacity will still be utilised, so in that sense there is no risk of stranded assets. There is some risk to firms that could result in firm closure (and the sale of the assets), although this is most likely if the providers of new capacity were small firms that only had assets built in response to this incentive. This is unlikely. As above, ideally the level of the generation obligation would be set in a way that resulted in a similar impact on electricity prices to that resulting from a CO_2 price measure.

On other issues, eg measurement and capacity building, capacity obligations provide no benefits.

2.9. Introducing New Markets—Guaranteed Prices/Feed-in Tariffs

2.9.1. Description

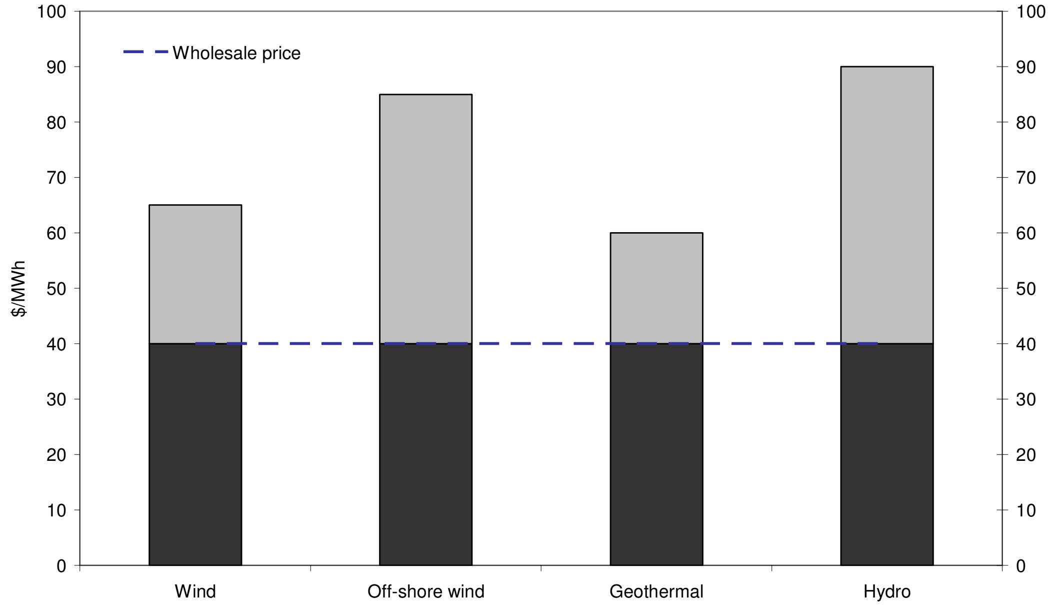
Providing a guaranteed price for electricity generation from renewables is an additional measure used in a wide range of countries in the form of a feed-in tariff. This approach has unique challenges for New Zealand, particularly because of the use of nodal pricing.

In Germany the feed-in tariffs were defined initially as a percentage of the average retail electricity price (eg 90% for wind, 80% for biomass, 65% for landfill gas); these percentages were fixed annually by the regulatory authority and paid by retailers.[24] From 2000, the system changed to a payment by the grid operator and for payments to be of a fixed amount, specified in cents per kWh.[25] The amount paid is specified at a rate sufficient to ensure investment, taking account of the costs of installation and expected load factors. It means that the amount paid per kWh differs with the renewable type, ie more is paid for offshore wind than on-shore wind.

The feed-in tariffs are viewed as being particularly successful in Germany. Renewable generation more than doubled between 2000 and 2004, from 14TWh to 37TWh.[26] The review of EU support measures undertaken by the Fraunhofer Institute[27] suggested that feed-in tariffs had been more successful than other measures, and specifically quota systems (obligations) in encouraging wind energy.

Figure 12 illustrates the requirements with a hypothetical example. It shows an expected wholesale price of $40/MWh and higher costs of entry (or average generation cost) for different plant types. The feed-in tariff system would provide a guaranteed payment to generators. Using the costs below, a guaranteed payment of $70/MWh would be sufficient to encourage entry by wind and geothermal plants.

Figure 12 Feed-in Tariff Requirements for Hypothetical Plants



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[24] Oxera (2005) Renewable support policies in selected countries. Report prepared for National Audit Office.

[25] Oxera (op cit); Bundesministerium fur Umwelt, Naturschutz und Reaktersicherheit (2003) Amending the Renewable Energy Sources Act. The government draft of 17 December 2003 in detail.

[26] REN21 Renewable Energy Policy Network (2005) Renewables 2005 Global Status Report. Worldwatch Institute. Washington DC.

[27] Fraunhofer Institute Systems and Innovation Research and Energy Economics Group (op cit)

The operation of a feed-in tariff system in New Zealand has some practical difficulties relating to the operation of the wholesale market and particularly the system of nodal prices that provide locational signals. Prices obtained by generators, or paid by load customers, are determined in the wholesale market and may be set via a contract or the spot market price. All reflect the marginal costs of supply to some degree.

Nodal prices are determined as a result of supply side bids at different injection points modified by adjustments to take account of the costs of transmission losses and constraints, and given forecasts of demand. This provides price signals to generators. By connecting closer to load, a generator can bid its power in at a higher price and obtain some of the rent available because of the higher costs of transmission from other generators. A feed-in tariff consistent with the nodal pricing system would need to provide differential payments depending on where in the country the plant was located.

It is likely that the system would operate as a contract for differences, ie the payment to a renewable generator would be the difference between some agreed contract price (the feed-in tariff) and the market price. It is assumed that the renewable generator is a price taker and would bid a low price to ensure dispatch. The issue then becomes how to set the tariff that would provide the locational signal, particularly relating to losses. Most likely this could be achieved through some historical average of differences in nodal prices,[28] or it could be made dynamic by establishing the feed-in tariff that applied at a single node (eg Haywards), with the tariff at other nodes reflecting the difference in wholesale price.

Variations on the basic approach include systems that incorporate bidding, ie generators bid for the amount of feed-in tariff required or for a constant amount above any final price specified either at the nearest node or system average, eg $20/MWh above the wholesale price.

Subsidies can be paid either to the marginal additions to renewables capacity (or output), ie new plants only or to all plants, including existing plants. Payments only for new capacity minimise subsidy payments. The main objection, if any, would be over fairness—existing plants would not be eligible and payments to new plants would not be able to identify plants that would not have built without payment. However, as with other policy instrument examples that include existing plants, it leads to very large transfers to existing generators.

This approach might need to be modified for industrial plant where there is the opportunity to influence the use of alternative fuels at existing plants. Here payments to existing plants would be worthwhile.

In Section 2.8.1 it was noted that payments associated with generation obligations would provide less certainty to investors in new capacity than would capacity obligations. The same is true of government subsidies. There is future policy uncertainty

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[28] This might apply to every node or simply establish a different price for South Island and North Island

over annual payments to generators that contrast with the certainty of an up-front capital (capacity) subsidy.

2.9.2. Efficiency

Feed-in tariffs can provide incentives for all types of renewables, although some systems have differentiated between types of generation that can give incentives that are not consistent with least cost. Least cost incentives are provided through a fixed payment (all bidders receive the same guaranteed amount) or through auction-based systems.

There are some risk-related issues that are likely to result in larger payments being required as output payments to generators than would be required in a capacity (capital) subsidy. Where there are costs to raising government revenue (which there are) this suggests that a capital subsidy will be lower cost.

A subsidy to new entrants on an output basis will result in additional new entry and no upward impact on electricity prices; rather prices will fall because of the shift in the supply curve. This moves prices away from the optimal price that trends towards the cost of new entry including a carbon price.

2.9.3. Practicality

A feed-in tariff system would require:

- A payment mechanism. This might simply be in the form of a contract between the new entrant generator and the government.
- A methodology for payment, eg guaranteed total price (as a contract for differences), guaranteed (constant) adder to the nodal price.

It would not necessarily need new legislation if it were developed as a contract.

2.9.4. Spill-over Effects

As noted above, the feed-in tariff would be expected to result in lower electricity prices.

2.9.5. Cost Incidence

The costs of the policy are borne by tax payers in funding the subsidy payments. There is some cost that is passed on to generators in the form of reduced revenues from electricity sales; there is a corresponding benefit for consumers in lower prices.

2.9.6. Sectoral Applicability

Feed-in tariffs could be used for industrial use of renewable fuel as a payment per MWh of heat or electricity produced from renewable sources. However, this introduces problems that do not apply in its use in electricity generation, because the subsidy is occurring at the margin, ie to units of energy used in setting (transfer) prices within a process, eg the price of heat (steam) as an input to pulp production.

Biomass use by forestry companies has a cost of collection. For marginal increases in output this is estimated at approximately $6/GJ ($40/tonne).[29] Subsidising a production input means that the firm pays less for a resource than the costs of supply. For example, if wood waste at $6/GJ is competing against coal supplied at $4/GJ, then a subsidy of at least $2/GJ is needed to displace coal. This then means that the company is using a resource that costs $6/GJ to supply in a production process that values it at $4/GJ. Those costs would be made up of transport and labour costs. The alternative approach that used a tax on coal that effectively increased its price to at least $6/GJ would result in the same response in the form of marginal shifts in fuel use to biomass, but would also result in an increase in total and marginal production costs and, possibly, to a reduction in production. In contrast, subsidising marginal inputs reduces production costs and potentially leads to increases in output. Thus, just as the instrument can lead to reductions in electricity prices, it can also lead to reductions in prices of industrial outputs.

2.9.7. Transition to a Long Run Measure

Feed-in tariffs are probably the least compatible with expected long run measures. There is a risk that if the tariffs are stopped in favour of the price incentive of an alternative instrument, the level of payment to investors falls. Unlike similar mechanisms based on obligations (eg generation obligations), there is little scope for the development of a contractual hedge to reduce risks. Because the payment is guaranteed by the government (or is for the duration of the policy), there is no market participant with which to contract an agreed future string of payments. It means there is a risk that very significant payments will be required to obtain entry.

2.10. Introducing New Markets—Labelling

“Green electricity” tariffs have been introduced in a number of countries to encourage consumer demand for energy generated from renewables. The theory is that, if consumers express a preference for renewable electricity, and are willing to pay a premium for electricity generated from renewables, this will provide additional funding to support investment in renewables.

The difficulty with applying this in New Zealand is that there is already a very large proportion of renewable electricity and if all is branded as renewable for retail purposes, the quantity available is likely to be greater than the number of households and businesses willing to pay a premium. In addition, this is a development that can occur in the market (and is). There seems to be little need for a government role.

2.11. Instrument Combinations

A number of combinations of instruments can be used. We examine the following here:

- Carbon charges alongside direct renewable support systems;
- Capacity combined with generation obligations.

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[29] Carter Holt Harvey estimates

2.11.1. Carbon Charge plus Renewables Support

Policy development focussed on a carbon tax is being pursued by the government. It is possible that a narrow-based carbon tax will apply to the electricity generation industry. This would provide additional incentive for new renewable generation and would lead to an increase in electricity prices reflecting the carbon content of marginal generation.

A number of instruments could be introduced on top of this. This would include subsidies and obligations. In fact the charge-subsidy scheme could be used as a means for keeping the system fiscally neutral, ie all the revenue paid as a charge could be paid out as a subsidy for new capacity. This would operate like a feebate system used for motor vehicles (taxes on polluting/less efficient vehicles, subsidies for less-polluting/more efficient).

It should be noted that such an instrument is exactly equivalent to an industry obligation where the obligation changes with some measure of output and results in a need for industry to support investment in capacity (or output). There is no difference in incidence either. A tax that is used to fund a subsidy is exactly the same as industry would develop “voluntarily” under an obligation system.

This partly addresses the problem that measures, such as subsidies and obligations which are based on capacity, lead to additional renewable generation and to reduced electricity prices.

2.11.2. Capacity and Generation Obligations

The discussion in the earlier sections suggested that a capacity obligation (ie an obligation to provide capacity) or subsidy may be better suited to supporting renewable electricity but that a generation obligation would be required to support additional renewables in industry. This is because, for electricity, a reduced amount of payment would be required to support renewable entry on a capacity basis in comparison to what would be required as a payment on a generation basis. A capacity-based system could also include the residential sector, but for industrial use of renewables, capacity cannot necessarily be restricted to a specific fuel type. Could an instrument be introduced in which the nature of the obligation was different for the individual sectors?

Clearly a combination is possible if the sectoral systems were kept separate, ie if there is a system for industry and a separate obligation system for electricity generation. However, there are greater advantages and efficiencies if the systems can interact. This would require that there was a conversion factor for turning a MWh of generation into its capacity equivalent (or vice versa). This is possible. It needs assumptions (industry or plant specific) of the expected load factor, years of plant life and a discount rate.

2.12. Summary of Effects

Table 8 summarises the effects of the different instruments.

Table 8 Summary of Effects

	Carbon charge	Energy charge	Capital subsidy	Capacity obligation	Generation obligation	Feed-in tariff
Efficiency						
Optimal supply of renewables	✓▯					
Encourage all types	✓▯	✓▯	✓▯	✓▯	✓▯	✓
Elec price = LRMC + carbon	✓▯					
Practicality						
New legislation	✓▯	✓▯		✓▯	✓▯	
Spill-over effects						
Electricity price rises	✓▯	✓▯		✓▯	✓	
Electricity price falls			✓			✓▯
Cost incidence[1]						
Passed-on	✓▯	✓▯		✓▯	✓▯	
Absorbed						
Sectors						
Electricity	✓	✓	✓	✓▯	✓	✓▯
Industry	✓▯	✓▯			✓▯	✓
Households	✓	✓	✓	✓▯		
Compatibility with long run measures						
	✓▯	✓▯	✓▯			

[1] In all instances the extent to which the cost is passed on depends on the competitiveness of the industry and whether prices are set by the firms covered by the instrument or, for example, prices are set internationally

Carbon charges, or other price instruments that ensure emitters pay the international price of carbon, are the most efficient instruments, resulting in an optimal quantity of renewables supply. They also result in electricity prices increasing to reflect new entry costs including a carbon price.

If going beyond this market-defined optimal quantity of renewables, a number of instruments can be used, including some of these instruments in combination with a carbon charge.

All instruments can be designed to provide incentives for all types of renewables, ie without differentiation. This is clearly efficient because it enables renewables to be added in order of least cost.

Capital subsidies can be used in electricity and household sectors. They lead to reductions in electricity prices because there is no impact on the costs of generation at the margin and the supply curve for electricity is pushed to the right, meaning lower cost plants are setting price. Feed-in tariffs are a generation subsidy. They similarly lead to reductions in electricity prices, but can be applied to industrial sectors also. In both instances, the costs are borne by tax payers. Subsidies might be introduced without the need for new legislation; it is likely that contracts could be used as the basis. This would provide less certainty than legislation, which will be particularly relevant for generation subsidies that rely on ongoing payments.

Capacity and generation obligations will require new legislation. They can be specified in a way that increases the level of obligation with increased levels of activity, ie the more that you generate the more capacity or renewable generation you need to supply (or hold certificates for). This introduces a marginal effect, leading to increases in electricity price.

All instruments can apply to the electricity sector. Capacity-based instruments, ie those that result in more new capacity are less suitable for application to industry because industrial potential for renewables includes the possibility of additional input to current capacity. In contrast, generation-based instruments, eg subsidies or obligations based on generation, are not suitable for the household sector. This is because of the need for monitoring (and verifying) output; the monitoring requirements would be too costly.

The instruments that are most compatible with the expected form of long run measures to tackle climate change are price instruments (carbon or energy charges). In addition, capacity subsidies can be compatible because they encourage new supply without placing too high an expectation in the market of future revenues. There is some risk associated with obligations that the impact on electricity prices will be greater than under the long run instrument, but the greater risk is associated with instruments that provide an additional revenue stream to renewable output, ie per MWh. The level of reward per unit of output may be greater than would result from a carbon price instrument leading to lower than expected returns to capital investment.

3. Conclusions

3.1. Discussion

Whichever policy instrument is used to encourage renewables it is likely to lead to the same resource costs for a given quantity of additional renewable entry that results; this is the additional cost of renewables over the costs of alternatives displaced. However, the instruments differ in a number of important aspects that affect their economic efficiency and likely effectiveness. We address these below using a series of questions.

Is anything more required than a price on carbon?
A price instrument such as a carbon charge or a cap and trade system would encourage the introduction of more renewable energy in all sectors. In theory it would lead to optimal investment in renewable capacity. If the reason for introducing policy to encourage renewable energy is to address climate change, and the government is indifferent about how much renewables capacity there is, then a carbon price instrument is the only instrument required.

If additional quantities of renewable generation are desired, for whatever reason, then using a price instrument may not be least cost, because it would have other effects also. These include fuel switching amongst thermal fuels, eg from coal to gas.

Should price or quantity instruments be used?
Both price and quantity instruments are analysed above. Price instruments include charges on carbon or energy, and subsidies paid to encourage additional capacity or additional renewable generation. Quantity instruments include obligations that could be applied to specific firms or sectors requiring them to meet specific quantity obligations, eg a specified level of capacity installations in a time period.

In general, price and quantity instruments can be specified in similar ways, but price instruments give greater cost certainty but outcome uncertainty, whereas quantity instruments give certainty on quantity but uncertainty on cost.

The quantity instruments as specified enable the government to pass the costs on to industry, whereas subsidies require government funding.

Should the cost be borne by industry or government?
Wherever the costs are borne initially, generally they can be passed on, so the question may be better specified as whether costs should be borne by consumers or tax payers. One of the reasons for introducing policies to encourage renewables is because of market failures. Two examples were examined—the failure currently to internalise the costs of carbon and possible low reserve margins addition to insecurity of supply. The cost of measures to correct externalities is a legitimate cost to be borne by the industry. Where the costs go beyond this level, arguably it is to meet other (unspecified) benefits that are shared by society at large and more legitimately would be borne by tax payers.

This would suggest the suitability of measures that included a carbon charge and a subsidy for capacity or generation. However, note that if a carbon charge is not introduced, this combination of measures can be approximated by an industry obligation.

Capacity or generation?

There are advantages to both capacity and generation obligations that depend on the sector being targeted. For electricity, a reduced amount of payment would be required on a capacity basis to support renewable entry compared with what would be required as a payment on a generation basis. A capacity-based system could also include the residential sector. However, for industrial use of renewables, capacity cannot necessarily be restricted to a specific fuel type and a generation payment is required.

Should all renewables be included or only new capacity?

Some instruments provide payments to all renewables including existing capacity. Such approaches have been used in other countries, particularly where the renewable industry is in its infancy. In New Zealand there is a large existing renewable capacity and support payments to existing capacity, either as part of a government subsidy or in response to an obligation, will lead to significant transfers of wealth. This is unnecessary, will lead to excessive profits and is inefficient where there is a cost to raising revenues. Instruments should be limited, to the extent possible, to providing support to new capacity.

Do the effects on final prices matter?

The analysis suggests that the instruments differ with respect to the impacts on electricity prices and transfer prices within industries. Measures that impose a cost at the margin, either as a carbon or energy charge, a cap and trade scheme, or a renewable obligation that is based on total activity (MWh of electricity or heat), lead to increases in prices. In contrast, those measures that simply provide support for new capacity, either as government subsidies or obligations that are based on a firm's capacity, will lead to reductions in electricity prices.

What is better depends on the objectives, but we assume that efficient pricing is desirable. Efficient pricing of electricity occurs when prices reflect marginal costs of supply. Prices are regarded as most efficient when, on average, they equal long run marginal costs of supply, and this should incorporate the costs of carbon and other externalities. This is achieved if prices reflect the costs of entry (including carbon costs). This is most obviously achieved using a carbon charge or a cap and trade scheme.

If a carbon charge is introduced then ideally any additional instrument would not pass further costs on to electricity prices. This could be achieved either using a subsidy or a (capacity or generation) obligation based on capacity, ie an obligation to provide either additional generation or additional capacity where the obligation was proportional to the capacity of the firm. An obligation that was proportional to production would be more appropriate only in the absence of a carbon charge. This is because such an obligation would impose costs on marginal activity and thus lead to an increase in electricity prices.

How should the expected design of long run measures be taken into account?
It is most likely that, in the long run, greenhouse gas emissions will be tackled in a least cost way involving a comprehensive price instrument such as an allowance trading system (cap and trade). There is some risk that renewables support policies, introduced as interim measures, may lead to outcomes that are not consistent with the long run response. The greatest risk is if the interim measure provides high rewards per unit output from a renewable plant and that this high level of return is not sustained under a future carbon price instrument. In the electricity generation sector, the risk is not that of stranded assets. Rather, it is a risk that these plants will receive an inadequate return on capital. In contrast, for industrial uses of renewables there is some risk of stranded assets. This is because renewable fuels have a cost and their price relative to thermal fuels may be lower under a renewables support measure than a carbon price instrument. To ensure greater compatibility, instruments should be designed such that the marginal reward to a renewable plant is similar to, or at least is not higher than, that expected under a long run instrument.

3.2. Recommendations

A carbon charge or equivalent price instrument, eg a cap and trade scheme, is the most economically efficient instrument to tackle greenhouse gas emissions. It would provide incentives for an optimal quantity of renewables consistent with an objective of reducing greenhouse gases at least cost.

If additional quantities of renewable capacity and/or generation were targeted beyond those achieved by an efficient price instrument, instruments should be chosen that do not pass on a cost at the margin. Most appropriately this would be a subsidy system, given that electricity sector costs are largely internalised, and would apply on a capacity basis to electricity generation and residential use of renewables, and on a generation basis for industrial use of renewables. Alternatively an obligation of a similar form could be used, with the level of obligation proportional to plant (firm) capacity.

If no price instrument is introduced, then the most appropriate instrument would be an obligation to supply capacity (electricity generation and households) and generation (industrial use) in which the level of obligation was based on the activity levels in the electricity and industrial sectors.

Whichever instrument is used, there are benefits from policy certainty and stability over time. This might suggest using instruments that are based on legislation rather than contract, particularly for instruments that result in payments to new entrants on generation rather than capacity. However, if renewables support measures are regarded as interim measures only in a transition to a more comprehensive price instrument to tackle greenhouse gas emissions, then the emphasis should rather be ensuring compatibility with the long run measure. This would best be achieved through aiming for consistency in the level of reward at the margin to output from renewable plants.

Annex A: Modelling Wind Generation Potential

Table 9 and Table 10 are taken from East Harbour Management Services. They are data on assumed capacity and generation potential over time. These data were used to derive load factor assumptions as shown in Table 11.

Table 9 National Supply Curve Data for Wind Resources (MW)

		MW				Cumulative MW	
Confidence		2015		2025		2015	2025
	Price (c/kWh)	WACC 5%	WACC 10%	WACC 5%	WACC 10%	10%	10%
High	2-4	-	167	210	167	167	167
	4-6	900	110	1,025	545	277	712
	6-8	690	745	705	670	1022	1382
	8-10	545	525	505	525	1547	1907
	10-12	390	420	355	420	1967	2327
	12-14	280	365	260	320	2332	2647
	14-16	130	280	90	275	2612	2922
Medium	2-4	-	167	390	167	167	167
	4-6	1,685	205	1,925	1,020	372	1187
	6-8	1,295	1,400	1,325	1,260	1772	2447
	8-10	1,020	985	940	990	2757	3437
	10-12	730	785	665	790	3542	4227
	12-14	525	685	490	600	4227	4827
	14-16	240	525	175	520	4752	5347
Low	2-4	-	167	520	167	167	167
	4-6	2,245	270	2,570	1,360	437	1527
	6-8	1,725	1,865	1,770	1,680	2302	3207
	8-10	1,360	1,310	1,255	1,315	3612	4522
	10-12	975	1,045	890	1,055	4657	5577
	12-14	700	915	655	795	5572	6372
	14-16	320	705	230	690	6277	7062

Source: East Harbour Management Services (2005) Availabilities and Costs of Renewable Sources of Energy for Generating Electricity and Heat 2005 Edition. p106

Table 10 National Supply Curve Data for Wind Resources (GWh/year)

Confidence		2015		2025	
	Price (c/kWh)	5%	10%	5%	10%
High	2-4	-	-	885	-
	4-6	3360	470	3,425	2190
	6-8	1800	2760	1580	2070
	8-10	1070	1445	845	1235
	10-12	615	935	480	795
	12-14	370	680	295	505
	14-16	150	450	95	375
Medium	2-4	-	-	1665	-
	4-6	6,300	880	6,420	4,110
	6-8	3,375	5,170	2,960	3,880
	8-10	2,010	2710	1590	2315
	10-12	1155	1750	900	1490
	12-14	695	1280	555	945
	14-16	285	840	175	700
Low	2-4	-	-	2220	-
	4-6	8,400	1175	8,560	5,480
	6-8	4,495	6,895	3,950	5,170
	8-10	2,680	3,610	2,115	3,085
	10-12	1540	2,335	1200	1,985
	12-14	930	1705	740	1260
	14-16	375	1120	230	935

Source: East Harbour Management Services (op cit)

Table 11 National Supply Curve Data for Wind Resources (Load Factors)

Confidence		2015		2025	
	Price (c/kWh)	5%	10%	5%	10%
High	2-4	-	-	48%	-
	4-6	43%	49%	38%	46%
	6-8	30%	42%	26%	35%
	8-10	22%	31%	19%	27%
	10-12	18%	25%	15%	22%
	12-14	15%	21%	13%	18%
	14-16	13%	18%	12%	16%
Medium	2-4			49%	
	4-6	43%	49%	38%	46%
	6-8	30%	42%	26%	35%
	8-10	22%	31%	19%	27%
	10-12	18%	25%	15%	22%
	12-14	15%	21%	13%	18%
	14-16	14%	18%	11%	15%
Low	2-4			49%	
	4-6	43%	50%	38%	46%
	6-8	30%	42%	25%	35%
	8-10	22%	31%	19%	27%
	10-12	18%	26%	15%	21%
	12-14	15%	21%	13%	18%
	14-16	13%	18%	11%	15%

We performed a linear approximation for the Load Factor data as a function of the Cumulative MW data for a fixed year and WACC(10%). The results were as follows ◎

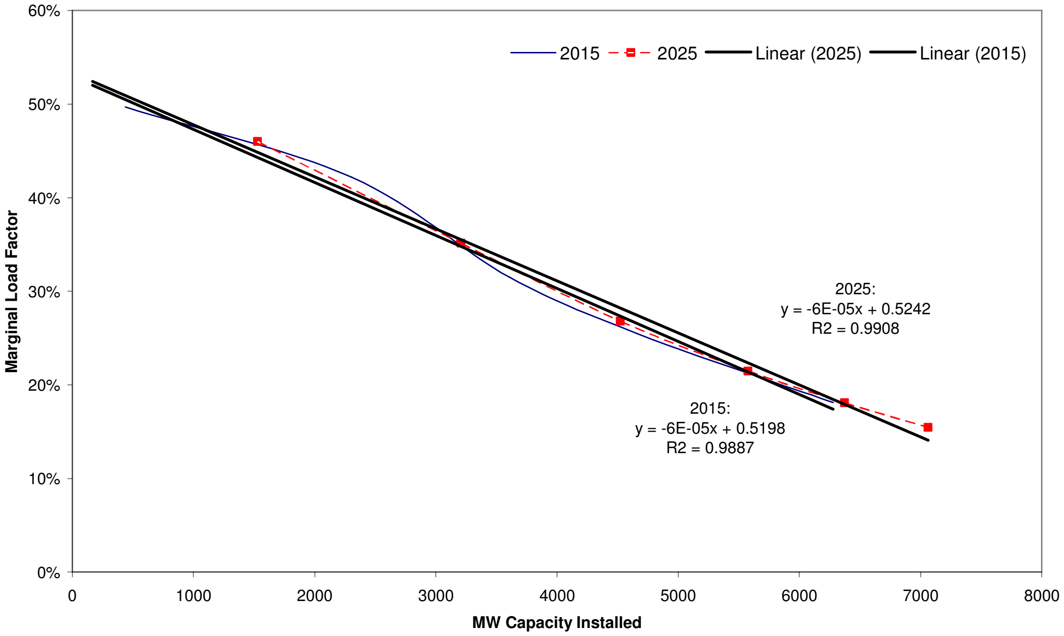
<u>2015</u> - LF = -0.0001303*(MW) + 0.5248 (High Confidence)
<u>2025</u> - LF = -0.0001371*(MW) + 0.5539 (High Confidence)

s the slope in the above equations is fairly constant over time, we have assumed the average value of the slope from both equations (for a given confidence level) as constant over time. The difference in the intercept is significant over time; therefore we modelled the intercept as a linear function of time getting the following results-

Intercept = (0.002913 * Year) - 5.34496138969 (High Confidence)

Using the above equations we can calculate the Load Factor for a Wind generator, given the existing wind capacity and the year as inputs. Figure 13 illustrates the validity of using a linear approximation as a model for this metric (notice the high R^2 value)

Figure 13 Load Factor as a Function of Installed Capacity



Annex B: Definitions

These are definitions for terms used in Figure 1.

Feed-in tariff. A policy that sets a fixed price at which power producers can sell renewable power into the electric power network. Some policies provide a fixed tariff while others provide fixed premiums added to market- or cost-related tariffs. Some provide both.

Renewables portfolio standard (RPS). A standard requiring that a minimum percentage of generation sold or capacity installed be provided by renewable energy. Obligated utilities are required to ensure that the target is met, either through their generation, power purchase from other producers, or direct sales from third parties to the utility's customers.

Capital subsidies or consumer grants. One-time payments by the government or utility to cover a percentage of the capital cost of an investment, such as a solar hot water system or rooftop solar PV system.

Investment tax credit. Allows investments in renewable energy to be fully or partially deducted from tax obligations or income.

Tradable renewable energy certificates. Each certificate represents the certified generation of one unit of renewable energy (typically one MWh). These certificates allow trading of renewable energy obligations among consumers and/or producers, and in some markets like the United States allow anyone to purchase separately the green power "attributes" of renewable energy.

Production tax credit. Provides the investor or owner of qualifying property with an annual tax credit based on the amount of electricity generated by that facility.

Net metering. Allows a two-way flow of electricity between the electricity distribution grid and customers with their own generation. When instantaneous consumption exceeds self-generation, the meter runs forward. When instantaneous self-generation exceeds consumption, the meter runs backward and power flows to the grid. The customer pays for the net electricity used in each billing period and may be allowed to carry over net generation from month to month.

Reference: Source: REN21 Renewable Energy Policy Network (2005) Renewables 2005 Global Status Report. Worldwatch Institute. Washington DC