Transitional Measures

Options to move towards low emissions electricity and stationary energy supply and to facilitate a transition to greenhouse gas pricing in the future:

A discussion paper

This paper outlines possible transitional measures for the electricity and stationary energy supply sectors. Feedback is sought on these options to help with policy development.

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1. Foreword

Climate change is a serious global problem, which is galvanising countries, communities, and businesses around the world to take action.

New Zealand, too, must play its part. New Zealand's biologically based economy is vulnerable to the impacts of climate change. It threatens the future of our economy, environment and way of life.

Measures to reduce emissions are part of the government's wider objectives to ensure our economy remains competitive and sustainable into the future.

No matter what happens with the Kyoto Protocol, New Zealand needs to prepare for a world in which a cost is attached to greenhouse gas emissions. This is not a New Zealand government initiative; it is an international reality.

The cost arises from reducing greenhouse gas emissions, whether this is achieved through regulation, price-based instruments or other measures. While action to reduce greenhouse gas emissions will have a moderate cost, the predicted costs and risks of inaction are higher.

In the long term, action is needed across the economy. In the short term, actions to reduce emissions will be specific to each sector.

This discussion document deals with short-term measures to reduce greenhouse gas emissions in the energy sector. It is part of the draft New Zealand Energy Strategy – *Powering Our Future* - and suggests ways in which the energy sector can make the transition to broad based measures proposed for the long term. These are described in the discussion document *Measures to Reduce Greenhouse Gas Emissions in New Zealand Post-2012*.

Transitional Measures provides technical detail on how we can move to a low emissions energy system, which will provide our economy with an enduring competitive advantage.

I believe this will be cheaper for New Zealand than for any other country. New Zealand has a long tradition of providing much of our energy from local renewable sources. Already, about 70% of our electricity is generated from renewable sources – the third highest level in the developed world.

This is a tradition we want to build on. We as New Zealanders take pride in our natural environment, and we have a reputation for developing resourceful, innovative and pioneering solutions. This is another step towards our long-term aspiration of becoming carbon neutral in the energy sector.

I look forward to receiving your feedback on New Zealand’s future energy path.

Hon David Parker
Minister of Energy
Minister Responsible for Climate Change Issues

2 Executive Summary

Purpose of the paper

This discussion paper seeks feedback on the development of measures that could be implemented in the stationary energy sector over the next decade to meet the government's objective of moving towards low emissions stationary energy supply, and to facilitate a transition to greenhouse gas pricing in the future.

The paper is part of the draft New Zealand Energy Strategy (NZES), ***Powering our Future***, which sets out a vision for New Zealand's energy future of a reliable and resilient system delivering New Zealand sustainable, low emissions energy. The measures discussed here would contribute to the objectives of the draft NZES. The government plans to publish the final strategy in mid 2007, and to introduce the strategy's actions in 2007 and 2008.

The paper is a product of the climate change work programme on energy which is tasked with addressing incentives for renewable energy and disincentives for fossil fuel-based electricity generation. However, the paper also takes a broader approach to help meet wider NZES and climate change policy objectives.

Sectoral greenhouse gas emissions

Between 1990 and 2005, greenhouse gas emissions from stationary energy generation and industrial energy use rose by approximately 50 percent. Of this total, emissions from electricity generation increased by approximately 105 percent, while emissions from industrial energy use increased by approximately seven percent.

Energy models currently forecast that under a 'business as usual' (BAU) scenario greenhouse gas emissions from stationary energy generation and industrial energy use will increase by approximately 18 percent between 2005 and 2015. Emissions from electricity generation sector are forecast to account for approximately 30 percent of this increase.

The policy context

The objectives of the draft NZES include: maximising the proportion of energy which comes from our abundant renewable energy resources; reducing our greenhouse gas emissions; promoting environmentally-sustainable technologies; and maximising how efficiently we use our energy to safeguard affordability, economic productivity and our environment.

The draft NZES recognises that energy suppliers (and other sources) will increasingly be required to face a cost of greenhouse gas emissions. This is expected to make it more expensive to combust fossil fuels, and will act as an incentive to develop technologies that either eliminate greenhouse gas emissions or make the process more efficient. The draft NZES also recognises that policy measures to reduce greenhouse gas emissions from the stationary energy sector will need to provide investment certainty and not detract from economic development.

Climate change policy objectives are fundamental to the design of future energy policies. The government is developing a series of “whole of government” work programmes on climate policy. One of these work programmes is an assessment of broad (cross sectoral) measures to reduce New Zealand’s greenhouse gas emissions post 2012. These policy options are discussed in a separate discussion paper, ***Measures to Reduce Greenhouse Gas Emissions in New Zealand Post-2012***. In contrast, this paper examines measures that can be applied **prior to** 2012 to encourage low emissions energy supply and to facilitate the transition to greenhouse gas pricing in the future. For the purposes of the evaluation of options in this paper, a time period of 2007–2015 is assumed.

Although no decisions have been made, the government has a positive view on the use of economically efficient price-based measures applied broadly across key sectors of the economy in the longer term (i.e. Post-2012), provided such measures are consistent with New Zealand’s economic and sustainable development objectives and the longer-term international climate change policy framework.

Scope

This paper focuses primarily on stationary energy *supply.* Demand-side issues, such as measures to improve the energy efficiency of homes, are discussed in the National Energy Efficiency and Conservation Strategy (NEECS) and are not considered in this paper. However, some of the options addressed in this paper, such as price-based measures, would also influence demand.

More specifically, the sector focus is on electricity generation and industrial heat and power. Industrial process emissions (non-energy process emissions) do not fall within the scope of this discussion paper (as they are not covered in the scope of the draft NZES). However, many of the options discussed in this paper could feasibly be extended to cover industrial process emissions (these opportunities are identified in the summary section).

Method

While transitional measures should be seen as part of long term strategy, there should be sound arguments for implementing them on their own merits. Transitional measures should also meet criteria for the design of good policy. Criteria used in this discussion paper include:

- environmental effectiveness
- cost effectiveness
- impact on energy prices
- ease of implementation (including regulatory and administrative issues)
- compatibility with a long-term price on greenhouse gas emissions.

Other issues that should be considered include: stimulation of innovation; treatment of new entrants; regional and technological diversity, and applicability to the New Zealand energy sector.

The intent of this discussion paper is to provide a descriptive summary and brief evaluation of the different options. The evaluation is largely qualitative and comparative, so it does not provide a comprehensive cost-benefit evaluation of each intervention.

Options

The categories of policy measures considered in this discussion paper include:

1) emissions trading
2) a CO_2 charge (narrow based)
3) renewable obligations
4) incentives / subsidies
5) project based measures
6) direct regulatory options
7) voluntary measures.

Each group has a potentially wide number of options, depending on design decisions. One key design choice is whether a measure is to apply to electricity only, or to electricity and industrial heat and power. Another choice is whether a measure should apply to all existing capacity or production, or focus only on new capacity or investment.

Key questions

The various measures presented in this paper all have their respective strengths and weaknesses (see Table 3 in section 6) and ultimately the choice of measures will depend on the weighting given to various objectives of energy and climate policy. There will inevitably be trade-offs to be made between different criteria, such as cost effectiveness, impact on energy prices and diversity of supply. Other key questions are:

- Who should bear the costs of the measures: emitters, consumers or the government?
- What impacts on energy prices are acceptable?
- Is certainty of price impact or certainty of outcome more important?

No one measure is likely to be sufficient to meet the draft NZES's overall objectives. A combination of measures may be necessary, as well as supporting policies such as providing information and encouraging innovation.

Principles guiding choice of measure

In the draft NZES, the government proposes a number of principles that could guide the choice of transitional measures. These are:

a) Measures should be compatible with, and enable a transition to, longer-term policy options where the cost of greenhouse gas emissions is reflected in the relative cost of the fuels that produce greenhouse gas emissions.

b) Investors in new generation should face a price signal that reflects the value of greenhouse gas emissions avoided for renewables relative to fossil fuels, either immediately or over a transitional period.

c) Owners of existing fossil fuel generation should follow a transitional path to facing the full cost on greenhouse gas emissions.

d) On electricity prices, the effect of any transitional measures on electricity prices should be gradual.

Based on the above principles, the government is attracted to measures which would support the early development of emissions trading in the sector.

3 Introduction

3.1 What is the purpose of this paper?

The purpose of this paper is to seek feedback on measures that could be implemented in the stationary energy sector over the next decade to meet the government's objectives of moving towards low emissions stationary energy supply and facilitating the transition to greenhouse gas pricing in the future.

This paper is part of the draft New Zealand Energy Strategy (NZES), ***Powering our Future,*** which sets out a vision of a reliable and resilient system delivering sustainable, low emissions energy. The measures discussed here are options that would contribute to draft NZES objectives.

The paper is also a product of the climate change work programme on energy which is tasked with addressing incentives for renewable energy and disincentives for fossil fuel-based electricity generation. However, the paper also takes a broader approach to help meet wider NZES and climate change policy objectives.

3.2 When would the measures be introduced?

The government plans to take decisions on these measures in 2007. Any measures would be introduced in 2007 and 2008.

3.3 Responding to this document

All the policies suggested in this paper are in draft form. The government welcomes your feedback to help build on these ideas and to develop transitional measures for New Zealand.

Throughout the document, there are specific questions in shaded boxes to guide feedback. We also welcome your feedback on other related issues.

Making a submission

Comments should be submitted by 30 March 2007. They should be emailed to transitionalmeasures@med.govt.nz or posted to:

Transitional Measures
Ministry of Economic Development
PO Box 1473
Wellington

3.4 What happens after you have made your submission?

After all the submissions have been compiled, the government will consider them when it develops its transitional measures.

Please note that your comments will be subject to the Official Information Act 1982 and may need to be publicly released. If you object to the release of any material provided in your submission, please specify the material that you wish to be withheld, and the grounds for withholding. All such requests will be reviewed carefully in considering any requests for release of the submission.

4 Context, Objectives and Scope

4.1 Context

Between 1990 and 2005, greenhouse gas emissions from stationary energy generation and industrial energy use rose by approximately 50 percent.[1] Of this total, emissions from electricity generation increased by approximately 105 percent, while emissions from industrial energy use increased by approximately seven percent.[2]

Energy models currently forecast that, under a 'business as usual' (BAU) scenario, greenhouse gas emissions from stationary energy generation and industrial energy use will increase by approximately 18 percent between 2005 and 2015.[3] Emissions from the electricity generation sector are forecast to account for approximately 30 percent of this increase.[4]

The draft NZES recognises that energy suppliers (and other sources) will increasingly face a cost for the greenhouse gas emissions they produce. This is expected to make it more expensive to combust fossil fuels, and will act as an incentive to develop technologies that either eliminate greenhouse gas emissions or make the process more efficient.

4.2 Objectives

The objectives of the draft NZES include: maximising the proportion of energy which comes from our abundant renewable energy resources; reducing our greenhouse gas emissions; promoting environmentally-sustainable technologies; and maximising how efficiently we use our energy to safeguard affordability, economic productivity and our environment.

It recognises that policy measures to reduce greenhouse gas emissions from the stationary energy supply sector should provide investment certainty and should not detract from economic development.

Although no decisions have yet been made, the government is in favour of economically-efficient, price-based measures applied broadly across key sectors of the economy post-2012. Any measures introduced would have to be consistent with New Zealand's economic and sustainable development interests and with the longer-term international climate change policy framework.

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1 Ministry of Economic Development, New Zealand Energy Greenhouse Gas Emissions 1990–2005, 2006.

2 *Ibid*.

3 Ministry of Economic Development, *New Zealand's Energy Outlook*, 2006.

4 *Ibid*.

Options for a broad price-based measure or a group of measures to be applied after 2012 are set out in a separate discussion paper, ***Measures to Reduce Greenhouse Gas Emissions in New Zealand Post-2012***. In contrast, this paper examines measures that can be applied **prior to** 2012 to encourage low emissions energy supply and to facilitate the transition to greenhouse gas pricing in the future. For the purposes of the evaluation of options in this paper, a time period of 2007–2015 is assumed.

4.3 Scope of this discussion paper

The scope of this discussion paper can be defined in three ways: the supply of energy, coverage of sectors or sub-sectors, and the types of measures possible.

First, this paper focuses primarily on the supply of energy.

Demand-side issues, such as measures to improve the energy efficiency of homes, are discussed in the NEECS[5] and are not considered in this paper. Nonetheless, some of the options addressed here – such as a narrow-based CO_2 charge – would also influence demand.

A second boundary marker is the coverage of sectors or sub-sectors. This discussion paper focuses on electricity generation and stationary industrial heat and power.

Some of the options discussed here apply only to electricity generation, whereas others cover both electricity and industrial heat and power. The reasons for selecting a narrower or broader coverage are discussed when these options are presented. This paper does not consider:

- The supply of energy to small- to medium-sized businesses and to homes, although some of the measures could also feasibly be extended to these areas. However, any measures that have an impact on electricity generation will have an indirect impact on the commercial and residential sectors, which are major electricity consumers.
- Industrial process emissions (non-energy greenhouse gas emissions), as they are not covered in the scope of the draft NZES. However, many of the options discussed here could feasibly be extended to cover industrial process emissions. From a climate change policy and efficiency perspective, this may be desirable.
- Transport energy, which is being addressed in separate policy proposals under the draft NZES. This paper also does not include industrial energy for vehicle equipment, such as those used in agriculture, construction, forestry, mining, and fisheries.

A third boundary marker concerns the type of measures being discussed. The only measures explicitly excluded from analysis in this paper are broad price-based measures designed to cover several sectors of the economy.

This leaves a wide range of potential measures available for discussion, including various economic instruments (price-based measures), and regulatory and voluntary methods.

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[5] As an option for further investigation, the NEECS is also considering an energy efficiency obligation, which could be classed as a demand side transitional measure.

4.4 What is meant by 'transitional'?

As mentioned above, policy objectives and measures post-2012 are covered in a separate discussion paper.

This paper looks at measures that can be implemented in the electricity and stationary supply energy sectors in the near term, and that could enable – or, at least, not be incompatible with – a transition to a mix of policies post-2012.

Determining suitable measures is not an easy task, given the uncertainty of longer-term domestic policies and international climate change policies after 2012. Nevertheless, the government has indicated that the discussion on long-term policy measures should include consideration of the option to introduce a price on greenhouse gas emissions across the New Zealand economy. The government believes a mix of price-based, regulatory and voluntary measures may be needed to achieve New Zealand's long-term sustainable development objectives.

4.5 Method of evaluation

Transitional measures should be seen as part of the long-term strategy, but there should also be sound arguments for implementing them on their own merits. They should also meet criteria for good policy design. Criteria used to assess the measures in this discussion paper include:

- environmental effectiveness (the extent to which the intervention will achieve emission reductions beyond BAU)
- cost effectiveness (the measure's ability to reduce emissions at a low cost, or the least possible cost)
- impact on energy prices
- ease of implementation (including regulatory and administrative issues)
- compatibility with a long-term price on greenhouse gas emissions.

Other issues of relevance include: stimulation of innovation; treatment of new entrants; and regional and technological diversity, as it applies to the New Zealand energy sector.

This discussion paper guides the discussion by providing a descriptive summary and brief evaluation of the different options. The evaluation is largely qualitative and comparative: the paper does not provide a comprehensive cost-benefit evaluation of each intervention.

It is unlikely that any one measure will be sufficient to meet the overall objectives specified in the draft NZES. A combination of measures may be necessary, as well as supporting policies such as providing information and encouraging innovation.

5 Policy Options

A wide range of policy options is available to encourage low emissions energy supply and a transition to greenhouse gas pricing.[6]

There are many ways to categories these options, such as whether they:

- are mandatory or voluntary
- rely on market (price-based) signals to steer investment decisions or regulations to directly encourage or discourage certain types of activity or technology (such as renewables).

The groups or categories of policy measures considered in this discussion paper include:

1) emissions trading
2) a CO_2 charge (narrow based)
3) renewable obligations
4) incentives/subsidies
5) project based measures
6) direct regulatory options
7) voluntary measures.

Each of these groups has a potentially wide number of options, depending on design. One key design choice is whether a measure is to apply to electricity only, or to electricity and industrial heat and power. Another is whether a measure should apply to all existing capacity or production, or focus only on new capacity or investment. These choices will determine the effectiveness of the measures, as well as their impact on energy prices or other costs.

This paper attempts to limit the discussion to two or three options for each category. Each option could be implemented in the near term. The resulting list of options is by no means exhaustive.

5.1 Emissions trading

An emissions trading scheme requires a group of emitters to hold tradable units or allowances to match some or all of their greenhouse gas emissions over a defined period. Emitters can either reduce their own emissions or trade allowances to meet their obligations. While there are a number of types of emissions trading schemes, two principal options analysed in this paper are the cap and trade and baseline and credit models. The difference between the two is that the cap and trade model uses an absolute framework, in that allowances must be surrendered to the authorities for every

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6 Some of the information in this document was sourced from some preliminary analysis by Covec Ltd commissioned by the Ministry of Economic Development and the Energy Efficiency and Conservation Authority. Covec's report is titled *Policy Options to Encourage Renewable Supply.*

tonne (or other unit of quantity) of emissions produced, while the baseline and credit trading model uses a relative framework, where only deviations from an emissions baseline must be accounted for.

Emissions trading schemes are particularly suited to sectors in which emissions can be estimated and reported accurately at low cost, which have a reasonable number of emitters, and in which the transaction costs of covering those emitters are not unreasonably high. The stationary energy sector and industrial processes sector generally fulfil these requirements and have been the main target for these kinds of measures internationally.

A third option is to allow for trading of cross-sectoral offset credits, either as a stand-alone model or along with either cap and trade, or baseline and credit models. Alternatively, any emissions above a specified level could be required to be compensated for with offset credits, which would in turn be tradable.

5.1.1 Cap and trade

The main feature of a cap and trade scheme is that a fixed ceiling or cap is set for a certain type of emissions (international examples are CO_2 and NO_x) over a set period of time in combination with tradable emission allowances. A cap and trade scheme is in effect a regulation with a market component. The allowances are initially allocated in some way (e.g., based on historical emissions, auctioned or purchased at a fixed price), typically among existing sources. Each source covered by the programme must hold allowances to cover its emissions, and is free to buy and sell from other sources.

Essential elements of a cap and trade scheme are:

- emissions are capped at some level in each period
- permits to emit greenhouse gases are issued for each period
- there is a penalty for non compliance.

Key design issues include:

- point of coverage
- threshold for entry
- use of offsets
- methods of allocation of allowances.

The main allocation methods available are gratis or free allocation, auction, or setting a requirement to purchase project or offset-based credits. Gratis allocation methods include “grandparenting” of units to existing emitters on the basis of historic emissions, and providing units to emitters on the basis of projected emissions. Allocations need to be consistent with the concept of a cap on the quantity of emissions, so that the number of units allocated does not vary with changes in production levels. Unit allocations would generally be made before or at the start of a trading period, as the quantity of units to be allocated would be determined in advance.

For a more detailed evaluation of the implications of these design options, refer to the discussion paper on long term policy measures, *Measures to Reduce Greenhouse Gas Emissions in New Zealand Post-2012.*

Linkages with international markets

The introduction of a domestic emissions trading scheme raises the possibility of linking with trading schemes in other countries. The main argument for linking is the base economic argument for introducing an emissions trading scheme. The greater the scope of the schemes, the greater the range of mitigation options available to market participants – enabling the aggregate emissions cap of the linked schemes to be met at a lower cost.

Linking with other schemes could enable a New Zealand emitter to buy and sell units outside the domestic market. One option would be to link a domestic trading scheme to the Kyoto emissions trading market by trading assigned amount units, or other Kyoto 'currencies' such as emission reduction units (ERUs)[7] or certified emission reductions (CERs).[8] A second option would be to link a domestic trading scheme to another country's emissions trading scheme, such as the European Union's Emissions Trading Scheme (the EU ETS).

One benefit of linking is that it sets an upper limit or safety valve on the price of allowances, so the price on the domestic market cannot exceed the international price. Because linking requires some conformity between different schemes, the design of a domestic scheme is critical if linking is to be possible.

Evaluation

Environmental effectiveness

A key argument in favour of cap and trade schemes is that they provide a certain environmental outcome. A cap is set on emissions from the sector, and the stringency of the cap determines the reduction in emissions.

Cost effectiveness

A cap and trade scheme is a relatively low cost way of reducing emissions in some sectors, potentially including the stationary energy sector. This is because cap and trade regimes provide emitters with flexibility to identify and use least cost abatement opportunities across the sector.

Methods of allocation would impact on the cost effectiveness of the scheme.

A cap and trade regime with auction covering the stationary energy sector would be comparable in its cost effectiveness to a CO_2 charge. The major difference between the two systems is that a cap and trade scheme gives greater certainty as to the amount of emissions from the sector, whereas a CO_2 charge gives greater certainty about the cost.

A cap and trade scheme with grandparenting is a less cost-effective measure than cap and trade with auctioning.

[7] Created under Article 6 of Kyoto Protocol – Joint Implementation.

[8] Created under the Kyoto Protocol's Clean Development Mechanism (Article 12).

Impact on energy prices

The impact a cap and trade scheme has on energy prices will depend on the stringency of the cap, the methods of allocation, the stringency of non-compliance methods and the potential for cross-sectoral and wider market linkages.

A cap and trade scheme with auctioning could be expected to have a similar effect on energy prices as a CO_2 charge if the cap was set at a level that reduced emissions by about the same level. The price of electricity in any time period is set by the marginal cost of production (the costs of the last unit of production). Fossil fuel plants invariably set price because they have higher variable costs of generation than fossil fuel alternatives. Plants will need to surrender allowances for every unit of emissions, and this results in a cost for every unit of electric output from fossil fuel plants. Even if a firm is gifted allowances, the need to surrender an allowance means that allowances cannot be sold; this is a cost.

The effect cap and trade schemes with grandparenting or other methods of gratis allocation have on energy prices will depend on the level of grandparenting applied. The price effect can be reduced by increasing the amount of grandparented units, leading to a similar reduction in price impacts as achieved by reducing the stringency of the baseline applied under baseline and credit trading. However, in some market conditions, a cap and trade system with grandparenting may create additional price effects compared with baseline and credit trading if producers pass the opportunity cost of allowances on to consumers.

Ease of implementation

There can be substantial cost and time required to establish institutions to monitor, report and verify emissions and provide for allocation and trading of units under a cap and trade system. Industry participants would also be faced with costs and time developing expertise in emissions trading. To the extent that any gratis allocation of units is negotiated or tailored to individual companies or sectors, substantial time or resources may also be spent in determining allocations.

Compatibility with a long term price on greenhouse gas emissions

A cap and trade system is very compatible with a move to longer-term full-price measure, particularly if there are good linkages to an international market to help make the transition to an international price. A cap and trade system also offers a number of options to make a gradual transition to full pricing through initial gratis allocation of all or a portion of emissions, or through options to include price caps or offset trading. If an emissions trading scheme was to be adopted across the economy as a long-term measure, early adoption of a cap and trade system in the stationary energy sector would be a good opportunity to develop experience in trading and managing liabilities.

Other issues

Under a cap and trade scheme with grandparenting, an emitter is allocated a larger amount of units than under a similarly stringent baseline and credit scheme, and receives the units in advance. Those units are an asset available for trading and have an opportunity cost: using the units to match emissions from production means that those units are not available for sale. It is in the emitter's interests to pass on some or all of this cost to consumers if market conditions enable them to do so (if all producers in the market faced the same opportunity cost and there was no risk of being undercut by foreign producers).

Some firms could gain by simply ceasing production and selling their allocations. This might be considered a good outcome, especially if the firm uses an excessively greenhouse gas-intensive technology. If the firm ceases production, the credits can then be sold to other firms which can use them more productively. However, this could be seen as giving firms an unfair 'windfall' profit and providing them with a perverse incentive to shut down. Rules could be introduced to claw back the credits if a firm chose to shut down, but these rules could get complicated as firms could scale back their operations without shutting down completely.

5.1.2 Baseline and credit

In baseline and credit schemes, individual emitters are assigned an emissions baseline which represents a schedule of allowable emissions over time. These can be defined on an absolute or an intensity basis.

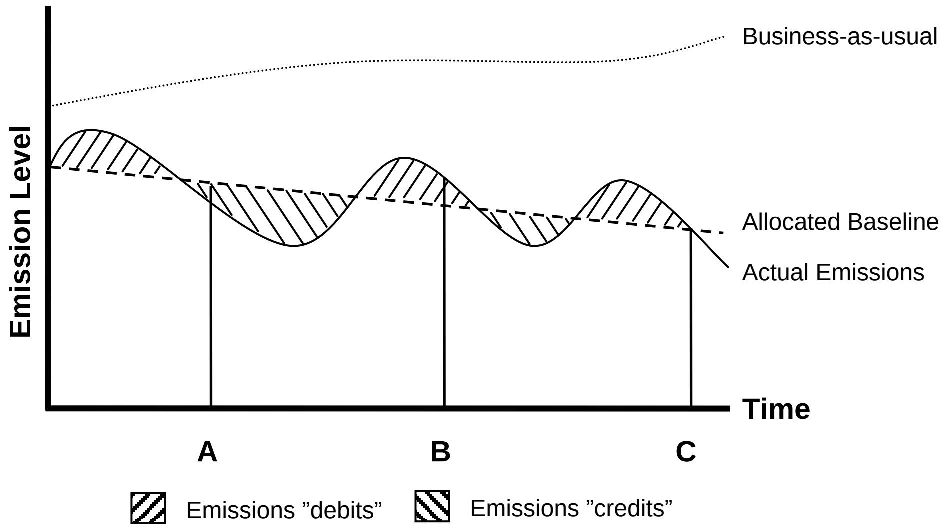
Emitters are exempt from carrying a liability for their emissions up to a baseline level, which has to be less than actual emissions to have a substantial effect. If the scheme is based on absolute emissions, it is no different from a cap and trade scheme with grandparented allowances. The only allowances likely to be traded are associated with deviations from the initial allocation.

Baseline and credit schemes start to differ from cap and trade schemes when they are designed on the basis of emissions intensity: sources must buy additional allowances when their emissions rate per unit of activity (energy input or output of energy or product) exceeds the baseline level. The system allows emitters to increase their total emissions without being required to buy more allowances, as long as the emissions are the result of increased activity rather than a change in the emissions intensity of the production.

For electricity generation, the baseline might be established on a straightforward basis as an allowed rate of emissions per MWh of output. For industrial energy, establishing the baseline would be more complicated. It might be established based on historical emissions use per unit of the firm's output (such as tonnes of commodity produced) or per dollar of output. However, any industrial baseline would need to be carefully designed to insure it was fair and did not produce perverse incentives, such as an incentive to produce lower-valued products. One obvious alternative would be to apply the baseline and credit scheme to electricity only.

For the purposes of this discussion paper, baseline and credit schemes are taken to operate on an intensity basis, with an emitter's baseline expressed in terms of tonnes of emissions per unit of production.

Figure 1: Unit allocation under a baseline and credit scheme[9]



A major distinction between baseline and credit schemes and cap and trade schemes is the timing of provision of allowances to participants. While the intensity baseline is determined in advance for baseline and credit schemes, the actual amount of production and the emissions intensity of that production is not known until the end of the year (or other period used). Consequently, emitters do not know the extent of their liabilities or benefits until the end of the period, when emission allowances are allocated. With cap and trade schemes, the amount of the cap is known in advance irrespective of production levels, so allowances can be allocated with certainty at the start of the period.

Evaluation

Environmental effectiveness

As with the other price-based measures discussed, the environmental effectiveness of a baseline and credit scheme depends on the stringency of the measure or on how much of an improvement the baseline is on business as usual. As defined here, the baseline is based on emissions intensity, which gives a less certain environmental outcome than a cap and trade system. Under a baseline and credit system, if overall production increases the total amount of emissions from the scheme can increase without emitters being required to meet any further obligation, as long as their emissions per unit remain below the baseline level.

Cost effectiveness

Baseline and credit emissions trading could be a relatively low cost way of reducing emissions from the stationary energy sector.[10]

9 Source: Australian Greenhouse Office.

10 However, as baseline and credit trading operates at the margin, it may offer less of an incentive to use least-cost emission abatement opportunities across the sector.

Impact on energy prices

Baseline and credit schemes imply a level of protection from an emissions obligation (up to the baseline). The impact on energy prices may be reduced by setting a less stringent baseline. A cap and trade scheme can have a similar effect by grandparenting emission units.

Ease of implementation

As with cap and trade emissions schemes, it could be expensive and time-consuming to establish institutions to monitor, report on and verify emissions, and to enable units to be allocated and traded. Industry participants would also be faced with costs and time establishing expertise in emissions trading. The financial risk to participants might be less with a baseline and credit scheme, as trading is at the margin and involves a smaller asset allocation.

A baseline gives each participant an emissions intensity target and a time frame in which the target must be met for each participant and sets out a time path along which emission reductions are to be achieved. To the extent that a company-specific baseline attempts to incorporate a detailed assessment of factors such as future industry performance and abatement opportunities available, establishing a baseline could be a cost-intensive process. However, this might not necessarily be any more complicated than allocation methods under cap and trade regimes (especially in the case of grandparenting).

There may be additional costs and complexities in a baseline and credit system associated with determining under and over-performance against the baseline, and to allocate units at the end of each time period, compared to an advance allocation of units under a cap and trade system.

However, a baseline and credit system may reduce some of the risks of windfall gains that are associated with a cap and trade system. Units under baseline and credit systems are based on actual production, so reductions in production should not create windfall gains.

Compatibility with a long term price on greenhouse gas emissions

A baseline and credit scheme gives a level of protection from the cost of emissions up to a baseline. However, it could be relatively easy to move towards full emissions pricing in the future by adjusting the baseline. The scheme could also help develop the expertise needed to set up a cap and trade scheme, but at relatively lower risk as there would be fewer assets and obligations involved.

Production increases in baseline and credit trading are unconstrained, which means the system has limits in enabling the sector to make the transition to measures that create a defined limit on emissions.

5.1.3 Trading of cross-sectoral offsets

The word ‘offsets’ or ‘offset credits’ describes a reduction or removal of greenhouse gas emissions that counterbalances emissions elsewhere in the economy. In the context of this paper, offsets can be activities that are funded by the electricity and industrial heat and power sectors to reduce or sequester emissions in other sectors, such as agriculture or forestry. The concept of offsets – or, more specifically, offset credits – and project-based activities described in section 4.5 often overlap because activities that generate offsets credits tend to be in the form of projects: an activity at an identifiable location that is individually managed and accounted for. This section looks at offset credits that are used in conjunction with emissions trading. One way of trading in offset credits is to design a trading scheme – such as cap and trade, or baseline and credit – and allow for offset credits to enter the market. This is a common feature of emissions trading schemes, and effectively means certain types of offset credits have the same value as an emission unit.

In general, allowing for offset credits as part of domestic trading schemes will improve both cost effectiveness and (more contentiously) environmental effectiveness and lessen the impact on energy prices compared with a 'closed' domestic scheme. This is because allowing for offset credits broadens the scope of a domestic trading scheme. This will help to reduce compliance costs for the sector facing the cap and, in theory, leaves net emissions unaltered. Trading in offset credits can also help to encourage emission reductions from sectors that are not as well suited to a cap and trade regime, such as the agricultural sector.

The main concern about offsets is whether the activities for which the credit is given genuinely reduce emissions (or, in the case of sequestration projects, remove emissions). This issue is discussed further in section 4.5. There is also concern that offset credits may weaken the capped sector's incentive to reduce emissions.

A second option would be to create a market that trades solely in offsets by requiring any additional greenhouse gas emissions from electricity and industrial heat and power sources to be compensated for by offset credits, which could be traded. This option is evaluated further below.

Evaluation

A system that requires offsets only on additional greenhouse gas emissions would operate at the margin and have less impact on price than an approach that put a cost on all emissions (such as a full CO_2 charge at the international price of emissions, or a cap and trade scheme without grandparenting). There would be fewer incentives to identify the least cost emission abatement measures than with options that applied a full price to all emissions.

It would also be necessary to determine what constituted new emissions, and who would take responsibility for them. One approach would be to allocate all emissions above 2006 levels between fossil fuel electricity and generators based on their percentage of total emissions.

A Trading Proposal from Trustpower

Description

This proposal combines features of a renewables requirement and an emissions trading scheme. The level of renewables requirement is set by the level of investment companies are willing to make in new renewable generation, rather than being set directly by the government.

Main features of the proposal

Investments in new renewable generation from 2008 through to 2017 (the "transition period") would be allocated permits each year for each tonne of emission reductions from new generation, based on a set electricity emissions factor.

Each year, existing fossil fuel generators would be debited for an amount of permits based on their proportion of emissions from generation, adding up to the amount of renewables permits allocated that year, Fossil fuel generators would be required to annually buy and retire permits to match their debit, which would create a domestic market. They would also be able to trade internationally, as the permits would either be Kyoto units or would be interchangeable with Kyoto units, creating an international price linkage. New fossil fuel generators would be required to provide units for *all* emissions from the start of the transition period, which they would have to buy on the international market. There would be a financial non-compliance penalty for fossil fuel generators.

After 2017 (or other chosen date), fossil fuel generators would be required to pay the full price of their emissions.

Alternative transition paths

The proposal includes a number of ways to vary the scheme to change the rate of transition to full greenhouse gas pricing, including:

- requiring fossil fuel generators to purchase permits to match renewables permits allocated *plus* permits for fossil fuel emissions over a 1990 baseline
- reducing the transition period to 2008–2012
- requiring new fossil fuels to face the full price of greenhouse gases from the start – paying credits for all their emissions from 2008
- making the transition to a financial penalty for non-compliance. Starting at $15/tonne and moving up to $25/tonne would effectively provide a maximum price ceiling for permits and would increase certainty of prices.

Trustpower's recommended transition path

A five-year transition period, with fossil fuel generators also to fund above baseline emissions.

Evaluation

This proposal is a combined carrot and stick approach, moving from mostly carrot to more stick at the end of the transition period. The effective subsidy for new renewables would become lower towards the end of the transition period, while the effective charge for fossil fuel generators would increase as more renewables came on line. During the transition period, this approach places a cost on emissions at the margin (with the margin being determined by the level of renewables uptake), which can limit impacts on wholesale electricity prices, depending on the transition path. However, if the transition period was shorter, or if new fossil fuel generation came on line, there might still be substantial price impacts.

Establishing international trading links would be a crucial part of the scheme as a solely domestic market would have only a small number of participants, and they could potentially be able to manipulate the market. If it was uncertain how much uptake of renewables there would be during the transition period, the charge to fossil fuel generators and the amount emissions were reduced by would also be uncertain.

The scheme would be relatively simple to administrate. For example, an additionality test for new renewables would not be needed. From the Crown's perspective, it would also be self funding (apart from administrative costs), as permits provided to renewable generators would be matched by a requirement for fossil fuel generators to provide permits to the Crown.

Questions for discussion

1) Which of the four emissions trading options discussed (including the Trustpower proposal) would be the most suitable transitional measure for the New Zealand stationary energy sector?

2) Do you support gratis allocation, auctioning or hybrid allocation schemes, and why?

5.2 A CO_2 charge (narrow based)

Description

Greenhouse gas emissions from energy production or industrial activity are a classic example of an economic externality. In other words, there is a negative consequence of this activity that the emitter does not take responsibility for. In theory, an ideal solution is to charge emitters the full cost of the pollution they produce.

In practice, it is extremely difficult to estimate the full costs of pollution, but a CO_2 charge aims to move towards society's preferred level of carbon dioxide by raising the price of the activity causing these emissions. A charge could change behaviour in both production and consumption patterns, depending on how much of the charge is passed on to consumers, and how much of it is absorbed by the emitter.

A CO_2 charge does not differentiate between types of energy supply, such as renewable energy sources, but gives equal incentives or disincentives to all energy supplies, based on their carbon content. For this reason it can be described as a 'technology neutral' intervention.

Ideally, a CO_2 charge would apply to emissions wherever they occurred in the economy. The feasibility and implications of using a broad-based greenhouse gas charge are considered in the discussion paper *Measures to Reduce Greenhouse Gas Emissions in New Zealand Post-2012.* Conversely, the focus of this discussion paper is on options for applying a charge on CO_2 only in the energy sector.

As is the case with all the options discussed in this paper, a number of design choices would have to be made to introduce a CO_2 charge. The most important choices would be:

- the rate of the charge
- how the revenue from the CO_2 charge would be used – a decision which would have a major impact on public attitudes to the charge[11]
- the definition of large emitters[12]
- the point of obligation. Decisions would have to be made on who is the liable party for a charge. The point of obligation can either be placed ***upstream*** on those who introduce greenhouse gases to the economy (such as coal mines, oil importers, gas extractors) or ***downstream*** on emitters, who combust fuel.

5.2.1 A CO_2 emissions charge on electricity and industrial heat

The introduction of a CO_2 emissions charge would change the cost of generation of electricity and heat from fossil fuel sources relative to renewables, as demonstrated in Tables 1 and 2.

Tables 1 and 2 show the impacts of a NZ$15/tonne, NZ$25/tonne and NZ$50/tonne price of carbon dioxide emissions.

Table 1: Impact of Carbon Dioxide (CO_2) Price on Electricity Costs[13]

	$15/tonne CO_2	**$25/tonne CO_2**	**$50/tonne CO_2**
Coal Generated	1.45 c/kwh	2.41 c/kwh	4.82 c/kwh
Gas Generated	0.52 c/kwh	0.87 c/kwh	1.74 c/kwh
Geothermal Generated	0.13 c/kwh	0.21 c/kwh	0.42 c/kwh

Table 2: Impact of Carbon Dioxide Price (CO_2) on Industrial Fuel Costs[14]

	$15/tonne CO_2	**$25/tonne CO_2**	**$50/tonne CO_2**
Natural Gas	$0.03/m^3	$0.05/m^3	$0.11/m^3
Sub-Bituminous Coal	$30/tonne	$50/tonne	$100/tonne

11 See the discussion paper *Measures to Reduce Greenhouse Gas Emissions in New Zealand Post-2012* for more discussion on revenue recycling options.

12 See the discussion paper *Measures to Reduce Greenhouse Gas Emissions in New Zealand Post-2012* for more discussion on thresholds for entry.

13 Electricity cost impacts were computed based on average 2004 emissions per kWh for each fuel. Emissions are given in *New Zealand Energy Greenhouse Gas Emissions 1990–2004,* Ministry of Economic Development, Tables 2.2.3 (for coal and gas) and E.14 (for geothermal). Electricity output is given in Ministry of Economic Development, *New Zealand Energy Data File,* January 2006, Table G.3.

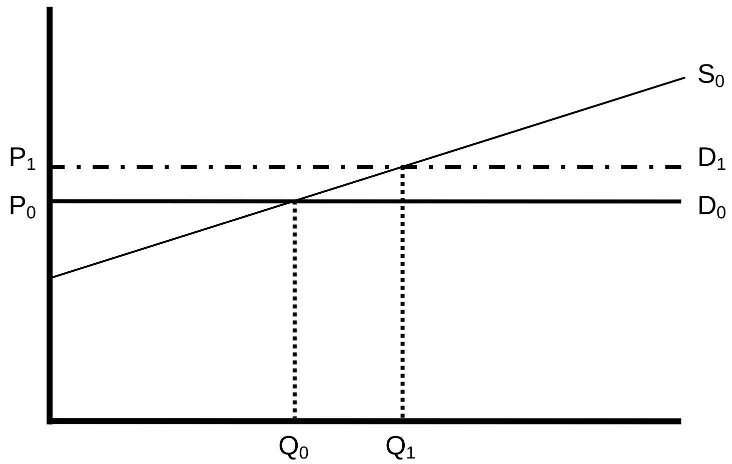
14 Industrial fuel cost impacts were computed based on kt CO_2/PJ emission factors given in *New Zealand's Energy Outlook to 2030*, Ministry of Economic Development, Section 4.3 and net energy contents shown in *New Zealand Energy Data File*, Ministry of Economic Development, January 2006, Table M.6 (gas) and M.4 (sub-bituminous coal).

Figure 2 illustrates the effect of a CO_2 charge on the demand for renewables. This figure pictures the current use of renewables as being the outcome of the costs of supply and demand for renewables.

The initial supply curve for renewables is (S_0). Demand for renewables (D_0) is pictured as a horizontal line based on the price of alternative fuel supplies. An amount is supplied under market conditions equal to Q_0. The impacts of a CO_2 charge are illustrated as a change in the demand curve; the new curve is pictured as D_1.

This change occurs because the cost of fossil fuel 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 be caused by building of new plant. Note that this is not an increase in total electricity supplied, which would decrease as a result of the CO_2 charge because of the increased wholesale price. Instead, it is an increase in the quantity of renewable energy supplied at the expense of supplies of fossil fuel fuels.

Figure 2: Impacts of greenhouse gas price on demand for renewables



Evaluation

Environmental effectiveness

As for the other price based measures discussed thus far, the effectiveness of a CO_2 charge would depend on the stringency of the measure: in this case, the level of the charge and the opportunities for fuel switching. Generally, CO_2 charges will be effective in terms of reducing emissions beyond business as usual. However, the environmental outcome of a CO_2 charge is less certain than the outcome of, for example, a cap and trade scheme, which sets an absolute emissions target.

Cost effectiveness

CO_2 charges (and other price-based measures) are generally regarded as cost effective because they set a price in the market and allow operators to use their own internal information to decide whether it is more cost efficient to reduce their emissions or pay the charge.

Impact on energy prices

Energy prices will rise under a CO_2 charge, reflecting the price of CO_2 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 CO_2. This is considered an efficient outcome.

In industrial heat and power use, the impacts include changes in supply costs and, in turn, the costs of production. In some cases, this leads to changes in output prices, depending on whether prices are set in the domestic market or internationally.

Additional entry of renewables may eventually reduce 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 and lead to some new entry.

For industrial uses of fossil fuel 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 fossil fuel 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, such as wood waste in existing solid fuel-fired plants.[15] In theory, these fuels could also be used in electricity plants, but it is more likely to occur closer to the fuel sources.

Ease of implementation

A CO_2 charge is conceptually simple and requires only the estimate of emissions – this is already undertaken for inventory purposes and is straightforward for fossil fuel combustion. New legislation would be required to introduce a CO_2 charge.

Compatibility with a long term price on greenhouse gas emissions

A narrow-based CO_2 charge would be broadly compatible with any future policy mix which included broad-based price measures such as an economy-wide CO2 charge or a cap and trade regime. A narrow-based CO2 charge would in effect introduce a price on emissions that would ensure those responsible for emissions began to take the 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, which would reduce the risk of stranded assets.

Other issues

A CO_2 charge would be passed on to firms in the form of higher electricity prices. A key issue to consider is how to manage this impact, especially for those firms which might have their competitiveness put at risk.

[15] This is limited to boilers that have a grate, e.g. it cannot be used in pulverised fuel plants.

Questions for discussion

3) Should a CO_2 charge on emissions for electricity and industrial heat be a preferred option as a transitional measure in the stationary energy sector?

If so:

4) How should the rate of the charge be set?

5) How should large emitters subject to the charge be defined?

6) Should electricity price impacts of the charge be managed? If so, how?

7) How should revenue from the charge be used?

5.3 Renewable obligations

Instead of targeting greenhouse gas emissions directly, policy measures can target renewable energy as a specific emission reduction solution. Industry participants can be required to demonstrate that a targeted quantity of renewable capacity is installed (capacity obligations) or output of electricity or heat is generated or sold (generation obligations).

Obligated parties must provide the renewable energy themselves or ensure it is provided by someone else. The obligation might be allocated to suppliers or retailers on the basis of their activity, such as the quantity of generation or the sales of electricity, or on the basis of capacity. It can also be allocated to generators. In addition, the definition of renewable energy has to be agreed so that the eligibility of different technologies is clear.

Compliance can be guaranteed by issuing green certificates when energy is generated from renewable sources or capacity is available for which the obligated party pays. The necessary components of such a system include:

- an obligation or target
- an obligated party
- a defined means of compliance and demonstrating compliance
- penalty regimes.

Most generation obligations are found in Europe, while most capacity obligations are found in North America.[16] So far, obligations have been introduced when renewable energy is more expensive than alternative, conventional electricity. In these situations, a monetary value has been placed on the green certificate, which raises the price paid for the renewable energy. For example, in the UK a buy-out value of 3p/kWh (around 9cNZ$/kWh) was implemented. It is possible, however, that no value is placed on the green certificate so that it remains mainly as a means to place an obligation and check compliance, although it is possible that a positive value may develop through trading.

[16] *Renewable Energy Global Status Report 2006*, REN21-Renewable Energy Policy network for the 21st Century, available on http://www.ren21.net.

In New Zealand, there would have to be careful consideration of how geothermal generation could fit into this scheme. Geothermal is generally considered renewable, but it does produce greenhouse gas emissions, the levels of which vary widely from field to field.[17] On average, these emissions per MWh are considerably lower than fossil-fuelled generators. However, greenhouse gas emissions from some geothermal fields are almost as high as those produced by fossil-fuelled generators.

5.3.1 Generation obligations

A generation obligation is specified in units of output. For example, a company might be required to ensure a percentage of its total supply or a specified quantity (in MWh) is generated from renewables.

Renewables Obligation

The UK Renewables Obligation requires electricity suppliers (retailers) to supply 15.4 percent of their output from approved renewable sources by 2015,[18] with lower annual targets in years before this date.[19] The obligation continues at this level until 2027. Renewables Obligation Certificates (ROCs) are allocated to renewable generators for every MWh generated from an approved source, and are purchased by electricity suppliers. The British government is not willing to meet the renewables target at any cost, so there is a price cap on ROCs. Suppliers have the option of purchasing ROCs either directly from a generator or by trading them, or paying a buy-out price of 3p/kWh. Revenue from the buy-out mechanism is subsequently returned to electricity suppliers in proportion to their holdings of ROCs. If there is an overall under-supply of renewables, ROCs are worth more than the buy-out price because the value of holding one includes the voided buy-out price and the returned revenue. The use of a buy-out makes it uncertain whether a target will be achieved but gives suppliers a new incentive to achieve a lower percentage of the obligation than 100 percent, which maximises their value. Achievement rates of the annual obligation have been around 70 percent.[20]

The UK Renewable Obligation only places an obligation on suppliers to buy an amount of renewable energy equivalent to a certain percentage of their previous year’s supply. All other negotiations about the contract are left to the generator and the supplier. These negotiations include the contract length, the price paid by the supplier and the amount of generation bought. This introduces a substantial amount of risk into the transaction, which makes it harder to obtain finance for new projects and new entrants.

The UK Renewable Obligation is un-banded, which means there is only one ROC value, suppliers have an incentive to buy the cheapest renewable energy. In the UK, this is energy from waste, such as landfill gas generation or wind energy. The obligation has not been successful in developing more expensive, less mature technologies, such as wave energy or tidal power.[21]

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[17] CO_2 is naturally released from geothermal fields to some extent, so the net impact may be less.

[18] *Reform of the Renewables Obligation and Statutory Consultation on the Renewables Obligation Order 2007*. An Energy Review Consultation. October 2006, para 2.2.

[19] 6.7 percent for 2006/07, rising to 15.4 percent by 2015/16.

[20] Ofgem, *3rd Annual Report on the Renewable Obligation*, 9 June 2006, available from www.ofgem.gov.uk.

[21] *Reform of the Renewables Obligation and Statutory Consultation on the Renewables Obligation Order 2007*. AN Energy Review Consultation, October 2006.

There are a number of renewable generation obligations and their details vary. For example, it is possible to incorporate minimum payments and/or minimum contract lengths, which reduces risks for investors.

In New Zealand, as with any country implementing an obligation, there may be initial market uncertainty over the price of green certificates because it would be a new market and it may take some time for price expectations to be defined. For investors in renewables, the risk is that certificate prices would be volatile. If there was any excess renewables capacity, it would fall outside the obligation and would not attract a ROC value. If there was under-supply, prices would be likely to rise to the costs of the non-compliance penalty (or the buy-out, if the UK approach was adopted). In addition, New Zealand may face market power issues that may not apply in larger countries.

5.3.2 Capacity Obligations

Capacity obligations would require total renewable capacity or new capacity within a given time period to equal a targeted amount. For example, each generator could have an obligation to hold renewable capacity equal to a specified percentage of its total, or a specified total in MW.

The Renewable Portfolio Standards (RPS)

The Texas RPS is a capacity-based scheme to ensure 2000 MW of new capacity is installed by 2009. The 2000 MW goals remain constant between 2009 and 2019. The RPS is set at 2880 MW to include current renewable energy and to ensure that any retiring capacity is replaced. The obligation is broken down into compliance periods for 400MW by 2002, 850 MW by 2004, 1400MW by 2006 and 2000MW by 2008. Each electricity retailer is required to obtain renewable energy capacity based on its market share of electricity sales times the renewable capacity goal.[22] The renewable capacity can be provided directly or through the Renewable Energy Credit (REC) market. The REC market operates in a similar way to the ROC market, although for capacity rather than output. Banking is allowed for two compliance periods. The penalty for non-compliance is the lesser of US$50/MWh, or 200 percent of the average market value of certificates for the compliance period in which the shortage has occurred. The Texas RPS has been successful, with the early compliance periods met. The Texas RPS, which is a state measure, has existed alongside the Federal Production Tax Credit, which has ensured a minimum payment and has reduced the level of risk within the mechanism.[23]

An obligation can apply to new or to all renewable capacity. For example, the obligation might be for 100MW per annum of new capacity or for 6500MW of total renewable capacity in some future year. If it is the latter, the obligation must make clear what new

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

[23] Langniss and Wiser, *The Renewables Portfolio Standard in Texas: an early assessment*, Energy Policy 31 (2003) 527-535; Bird et al, Policies and market factors driving wind power development in the US, Energy Policy 33 (2005) 1397–1407.

renewable energy is required, as Texas did but Maine did not. As a result, there has been minimal additional renewable capacity in Maine.[24]

An alternative specification is for the average percentage of all new generation, as a portfolio, to meet a target. This is easiest to achieve when there is considerable growth in demand, or if the target is 100 percent (all new capacity must be renewable). It becomes difficult if growth rates are low and plants are lumpy. Fossil fuel plants in particular are large, and if a company was to build a new fossil fuel plant it might be difficult to achieve targets. For example, a target of 75 percent of all new capacity would require a large additional investment in renewable generation to accompany any new fossil fuel plant.

As well as options for the nature of the obligation, there are options for the allocation. Aggregate obligations can be allocated to individual plants or firms in proportion to their percentage of capacity, or of generation or output:

- Their percentage of capacity can be either all capacity, or all fossil fuel capacity.
- Their percentage of generation or output can be all output (or sales), all fossil fuel output, or all CO_2 emissions.

For generation or output-based allocation, the obligation might be defined in the previous year (in which case each firm or plant is allocated the target divided by last year's activity), or it might be based on anticipated activity levels in the current year (the target is divided by expected activity this year to define a rate of allocation for each actual unit of generation). This may lead to some over or under-allocation of responsibility. Using last year's activity is likely to be a better option.

As with generation obligations, details of the different measures can differ. For example, it is possible to impose a minimum payment.[25]

Trading

While obligations can operate as regulatory measures in which obligated parties must either provide the renewables themselves or contract for it, generally these measures operate via a market mechanism in which the obligation (green) certificates[26] (such as ROCs or Texan RECs) are able to trade separately from the electricity. Under a market approach, for each unit of renewable electricity created, one unit of electricity enters the electricity market, and one green certificate enters the renewable obligation market. Some of the attributes of a green certificate market can be achieved through efficient contract markets, but tradable green certificates can in theory allow anyone entry to generate and, through trading volume (a liquid market) and price transparency, help provide the signals for least-cost achievement of obligations.

In Europe, the majority of obligations were implemented around 2000. At that time, it was envisaged that a green certificate market would develop and eventually link in

[24] *Ibid*.

[25] *Ibid*.

[26] Green certificates (GCs) are known by a plethora of other names, e.g. Renewable Obligation Certificates (ROCs in the UK), Renewable Energy Certificates (RECs e.g. in Texas), Tradable Renewable Certificates (TRCs), Green Tags, Green Labels, Green Tickets, Tradable Renewable Energy Credits (TRECs) and Renewable Resource Credits (RRCs).

some way with greenhouse gas emission trading schemes, which was considered a key benefits of the obligation. However, tradable green certificate markets have not developed either internally in the countries where the measure is in existence (such as the UK) or across borders (such as between Germany to France). The Netherlands was the only European country which initially allowed trans-border trade but closed the option when it became clear it was paying for existing renewable energy from other countries. In addition, there has been no increasing linkage of green certificates with greenhouse gas trading.[27]

Evaluation

Environmental effectiveness

Renewable obligations focus on promoting renewable energy. This means they are promoting a different and more limited outcome than some of the other measures reviewed in this paper, which can make comparison difficult. Literature reviewing the effectiveness of renewable obligations tends to focus on the programmes' success in encouraging new entry of renewables and diversity of supply.

An alternative way of addressing this criterion is to ask whether one particular mechanism will deliver greater investment and installation of renewables than business as usual. In general, a well-designed renewable obligations scheme can be expected to deliver more renewables than under business as usual, although probably less than the feed-in measure discussed later.

Cost effectiveness

In general, renewable obligations are unlikely to be as cost effective in reducing greenhouse gas emissions as price-based measures such as emissions trading and CO_2 charges. However, renewable obligations can provide incentives for new entry at least cost, reward investment in all types of renewable capacity, and reward all investors, depending on the detail of the design.

Obligation mechanisms can be un-banded, which means they do not specify any particular type of generation to be bought or capacity to be installed. The UK Renewable Obligation and the Texas RPS are both un-banded. In these cases, the generation or capacity supported through the obligation tends to be the cheapest available, and does not provide support for more expensive, less mature technologies. It is possible to 'band' obligations or design them to support particular technologies, although this can lead to difficulties in trading.

To meet a given level of new capacity, capacity certificate payments may be lower than generation certificate payments because of output uncertainties. For industrial use of renewables, capacity cannot necessarily be restricted to a specific fuel type, so a generation option may be preferable.

There is potential for market power where a single or small number of firms dominate the supply of certificates or where an area has only a single supplier which is purchasing generation and could exert influence on the price paid or the length of the contract.

[27] W. G. Arkel et al, *The Dutch Energy Policies from a European Perspective; Major developments in 2003*, ECN Report No: ECN-P-04-001, available on www.ecn.nl.

The price of certificates will depend largely on the expected duration of the policy and whether revenue from certificates can be expected over the life of the plant. If not, certificate prices will be higher.

Impact on energy prices

The impact on electricity prices will depend on how much generation or capacity the obligation is for and the value of the green certificate. As more generation is supported by an obligation mechanism, for example ten percent of the total market, then the size of the competitive market is reduced to 90 percent and the more expensive conventional electricity is pushed out so that the price of non-obligation electricity falls. If the combined cost of the obligation electricity and green certificates is equal or lower than the cost of the ten percent of conventional electricity, the price will stay the same or fall. If the combined value of renewable electricity and green certificate is higher than the average cost of electricity, then the average cost of electricity can be expected to rise.

In a country where renewable energy is no more expensive than conventional electricity, the green certificate value can be set to 0p/kWh. However, in general green certificates do have a value and the mechanism has led to an increase in energy prices. The extent to which this feeds through to energy bills will differ in each country or state using green certificates.

The impact on electricity prices will depend on who has the obligation. More specifically, prices will be affected if the level of obligation increases with each additional output of electricity. The impact is greatest if the obligation is concentrated on generators that are setting electricity price, such as fossil fuel generators. Basing the effect on last year's activity should not affect this result significantly, as the impact at the margin is simply discounted by one year.

An alternative way to express the obligation is on capacity – by obliging a firm to hold certificates in proportion to its total generating capacity. There is no change in the level of obligation with level of output, and no impact on the cost of electricity if the obligation provides no extra payment. However, there will be an extra cost if the obligation does lead to extra payment.

A benefit of an obligation for generation and capacity is that a maximum annual cost is roughly known, although it differs for different mechanisms. If a price per kWh and an amount of capacity is known, the maximum annual cost is known. If either capacity or price is known there is less certainty. The UK legislation allows the supply companies to incorporate their extra costs into their supply tariffs so that, ultimately, the costs fall on consumers and are paid via their electricity bills.

Ease of implementation

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

- an obligation or target
- an obligated party

- a defined means of compliance and demonstrating compliance
- penalty regimes for failure to hold enough certificates.

Establishing an obligation is more complicated than incentive mechanisms because of the need to check compliance. Trading would also increase the administrative burden.

A generation or capacity obligation, which has no minimum payment, obliges a supplier or retailer to buy the electricity and is integrated into the electricity market, just like any other generation bought by the supplier. This would make it easier to implement in the electricity market.

Compatibility with a long-term price on greenhouse gas emissions

Obligations require targets to be met. For example, most European countries have a target of an additional ten percent of electricity by 2010. These targets may or may not fit in with wider climate change targets, which makes them compatible with longer term options.

The main risk in making the transition to a long-run instrument would arise if the level of support of the transition measure was greater than the support that would be provided simply by putting a price on greenhouse gas emissions equal to international allowance prices. A further risk is that if a transition measure was not guaranteed a sufficient lifetime, it would not give investors confidence that they would be able to obtain a sufficient return on capital. The risks are not generally to renewable generation; if built, plants with no fuel costs would be expected to generate because of their low variable costs.

The way to ensure the greatest compatibility with the long-term greenhouse gas price signal is to either set targets that are consistent with the long-run expected response to an emissions price, or to continue a renewables support programme in the long run, alongside any price instrument.

Questions for discussion

8) Should a renewable obligation be a preferred option as a transitional measure?

If so:

9) Should the obligations be to provide capacity or generation?

10) Should the obligation be placed on generators or retailers (suppliers)?

11) Is there is a need for a buy-out mechanism to limit certificate price?

12) Should the obligation be un-banded?

5.4 Incentives

Other countries have used a number of mechanisms to subsidise investments in renewables capacity. These include capital grants; capacity bidding (for example the Non Fossil Fuel Obligation (NFFO) in the UK from 1990 to 1998) which includes a competitive element, and specified payments per kWh generated for additional capacity (for example, feed-in tariffs). Subsidy equivalents can also be provided in the form of tax deductions or accelerated depreciation.

5.4.1 Capacity grants and subsidies

Capacity subsidies are relatively straightforward in conception, if not in implementation. The government pays the firm or generator enough (or more than enough) in the form of a tax incentive or direct payment to ensure new capacity is installed. The subsidy could be paid in one lump sum or over time, once the generation plant was operating.

Once installed, as a result of a capacity subsidy, the renewables would be expected to operate in the market in an efficient way. Renewable energy-generating plants should have low variable costs of electricity generation, providing that financing repayments are low or zero (and excepting specially-grown biomass, such as energy crops which have ongoing costs). This should have an impact on market prices, pushing lower-cost plants to the margin in all time periods.

The amount of subsidy paid would depend on the competitiveness of bids to supply capacity, how many bidders there are, what the total amount of subsidy is available, the market expectations of future electricity prices and the expectation of future technology prices. As the government would bear some of the risk – such as decisions on other instruments to tackle greenhouse gas emissions – the government might choose to fund some elements of capacity may be consistent with optimal risk-bearing. The main approaches are:

- Published quantities of subsidy that could be provided, such as $per kW of capacity installed (including equivalent tax measures and reduced depreciation). The risk of this approach would be not discovering or stimulating lower bids or smaller levels of tax incentive. There would also be risks regarding the total amount that would have to be paid out if no limit was set on the total capacity that might be funded.
- Bidding. The only risk of this approach would be if the government announced in advance that it would purchase a given amount. If it retained all options, it could choose whether to purchase and how much to purchase solely on the basis of price offered. In this case, it would be important that there were effective penalties for non-installation of awarded contracts. If the penalty was not effective, bidders would have no incentive to bid in ‘real’ prices per kWh or per kW installed.

Evaluation

Environmental effectiveness

The definition that is used in this paper to assess environmental effectiveness is the extent to which a measure is reducing environmental emissions beyond BAU. A general discussion of this definition and how it can apply to a renewable energy support scheme occurred in section 5.3 and is not repeated here.

In general, a well designed renewable capacity bidding system could be expected to deliver more renewables than BAU, although probably less than the feed-in measure discussed later. The amount installed would directly relate to the amount of subsidy available.

Cost effectiveness

From an efficiency point of view, there are three issues of concern:

- whether the instrument can operate to achieve new investment in capacity at least cost
- the effects of how it is paid for
- the effects on electricity prices.

The ability to achieve increased capacity at least cost will depend on the approach used and, in particular, 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 and will lead to the cheapest technologies being developed. However, this approach will not provide support for a diversity of options. Capital grants and a banded capacity bidding system are able to provide support for a diversity of technologies but imply higher payments for certain technology capacity. These measures may be considered cost effective if support for new supply options is an important feature of a renewable support programme.

The bidding system can be designed to either pay just what is required to achieve more renewable entry, or to reward all renewables the same amount, regardless of what is required to achieve entry. The first two rounds of the UK's NFFO started off with the latter design and then moved to the former.

Bidding systems usually incorporate a competitive element in the bidding process. However, once a contract is awarded, the measure works in parallel to the electricity market rather than as part of it. This is because there is an obligation on the electricity companies to buy electricity at the bid price. This is similar to the feed-in mechanism.

Impact on energy prices

A capacity subsidy does not change the input or output prices directly, but can change total system prices. Any measures that increase the total renewables capacity in the electricity market will shift the supply curve for fossil fuel fuels (those with variable costs greater than zero or thereabouts) to the right, reducing marginal electricity prices. This is not an inefficient outcome in the short run, as resources will not be used in a market that values them at less than their costs of supply.

The total costs of the capital grants are not usually large enough to affect prices. Capacity grants are usually given by government programmes and paid for from tax, which implies that an annual maximum cost is known. Capacity bidding systems also enable the maximum annual cost to be known. How they are paid for differs. In the case of the NFFO, electricity companies were required to buy the electricity at a set price and then invoiced Ofgem, the energy regulator, which reimbursed them from government funds obtained from the general tax revenue. In this situation, the price of electricity would not increase. The cost of bidding systems could be passed on to consumers through their electricity bills. As with obligations, the impact on energy prices would depend on how much generation or capacity was subsidised and how much it was paid relative to the conventional electricity it displaced.

Ease of implementation

Capacity subsidies are relatively simple to introduce. Capital grants may not require new legislation, while a capacity bidding system is likely to require new or amended legislation.

The capacity bidding system would require the government to announce a desire for new renewable capacity and be willing to provide funding for it. Firms would be invited to bid and the government would select bids based on price and quantity. The design of the bidding system would have to be considered carefully.

When the NFFO was introduced in the UK competition was strong, and with limited subsidy funds and no penalties, bidders had an incentive to bid low prices. This increased their chances of being awarded a contract, and meant there was no penalty if they did not develop the project – as turned out to be the case for most of the projects in the latter bidding rounds. However, if the rules removed these incentives, a capacity bidding system would be similar to a feed-in tariff but with a competitive element and a quantified maximum annual cost to the government.[28]

Alternative approaches would include published subsidy values, such as $x per MW up to a maximum capacity or dollar amount. This would require a 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, such as $/tonne of CO_2 reduced.

Capacity grants can be open to abuse if there is not a clear incentive to maximise generation. Without such an incentive or penalty, grants may be given for installation rather than generation output. In addition, while grants should be given to take account of New Zealand costs, it is also important that they are linked to international capacity costs so that grants are not given for inflated costs.

Compatibility with a long-term price on greenhouse gas emissions

Capital subsidies can be compatible with a long-run measure. They provide payments to ensure investments are made in new capacity, although they are likely to lead to a reduction in electricity prices.

Under long-run price measures it would be expected that electricity prices would rise, 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.

5.4.2 Guaranteed prices/Feed-in tariffs

A wide range of countries used a feed-in tariff as a subsidy to providing a guaranteed price for electricity generation from renewables. Feed-in tariffs involve requiring electricity distributors or suppliers, depending on the country, to buy all renewable electricity offered to them at set prices. These prices differ for different types of generation (electricity from wind, electricity from photovoltaics, and so on). Feed-in

[28] C. Mitchell, *The Non-Fossil Fuel Obligation*, Energy Policy, 1995; and C. Mitchell, *The Non-Fossil Fuel Obligation and its Future*, Annual Review of Energy and Environment, 2000.

tariffs are able to support a diverse set of technologies, including the more expensive, immature technologies. For investors, it is a very low risk mechanism.

Feed-in mechanisms attract a wide diversity of investors, including new entrants who range from traditional energy companies to communities and individuals. This in turn enables heat and power plants of all sizes to be supported from domestic-scale distributed generation or small-scale wind farms through to large-scale wind farms or biomass CHP plants. In addition, new entrants may develop different projects from traditional energy companies, stimulating innovation and diversifying the supply options.

In Germany, the feed-in tariffs were defined initially as a percentage of the average retail electricity price (90 percent for wind, 80 percent for biomass, 65 percent for landfill gas). These percentages were fixed annually by the regulatory authority and paid by retailers. 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. 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: more is paid for offshore wind than on-shore wind. Contracts last for 20 years and there is a built-in reducing payment to take account of technological improvement. There are also rules ensuring connection to the nearest point of the distribution grid and specifying how the connection is to be charged. The overall cost of the scheme, which is no more per kWh than the renewable obligation in the UK for the equivalent technologies, is shared equally across customers. However, Germany pays a high price per kWh for photovoltaics and has recently moved ahead of Japan for domestic installation and MW sales.[29]

The feed-in tariffs have been particularly successful in Germany and Spain for a diverse set of technologies. Germany added 1,808 MW of wind energy in 2005 to take total capacity installation to 18,428 MW. Spain added 1,764 MW of wind energy in 2005, taking it to 10,027 MW.[30]

Germany used price to introduce particular types of renewable technologies, including photovoltaic energy. Spain has done the same but has also designed the mechanism to have more integration with the electricity market. A similar approach could be taken in New Zealand with, for example, marine energy.

Evaluation

Environmental effectiveness

In general, a well designed feed-in measure can be expected to deliver more renewables than business as usual, and probably more than other types of renewable energy support measure.

Feed-in tariffs are designed specifically to deliver renewable energy. Feed in tariffs have been demonstrated to be effective in terms of delivery of installed capacity. Feed-in tariffs can provide incentives for all types of renewables, of all sizes.

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29 Total Photovoltaic Power Installed in IEA PVPS available from http://www.oja-services.nl/iea-pvps/isr/22.htm.

30 Wind Power Installed in Europe, European Wind Energy Association website, available on www.ewea.com.

Cost effectiveness

The European Commission (EC) has recently reviewed the renewable energy policies of all the member states.[31] The EC review found that feed-in tariffs across Europe are generally no more expensive per kWh than obligation measures. Some feed-in tariffs have been unsuccessful in delivering capacity because their payment is too low. However, the total cost of a feed-in tariff measure can be high because of its success. Germany and Spain may not pay more per kWh for each unit of wind energy, but because they have both installed nearly two GW of wind energy in the last year – compared for example to the UK, which has installed less than that since 1990[32] – their total cost is relatively more. Even so, the German feed-in has raised the price of electricity to customers by only three percent, and given considerably more capacity.[33]

Impact on energy prices

In theory, a subsidy to new entrants on an output basis would result in additional new entry and no upward impact on electricity prices. Instead, prices would fall because of the shift in the supply curve. In practice electricity consumers may pay for the scheme through their electricity bills.

Ease of implementation

A feed-in tariff system would require:

- a payment mechanism. This might be in the form of a contract between the new entrant generator and the government, but is more likely to require an amendment to existing legislation or new legislation
- a payment method, e.g. guaranteed total price.

New legislation may not be needed if a feed-in tariff system was developed as a contract between the generator and the government. However, this is likely to be cumbersome for the government and it introduces another step in the process, as the generator also has to deal with the electricity distributor in order to connect and generate. Introducing new or amended legislation imposing the feed-in requirements on electricity companies would be administratively simpler, reducing the process steps for the generator to two: achieving planning permission and dealing with the electricity company.

Feed-in mechanisms are generally easier to implement than obligations. The European Commission report confirmed that obligations have higher administration costs.[34]

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[31] Commission of the European Communities, *The Support of Electricity from Renewable Energy Sources*, December 2005, page 42.

[32] Above n 16.

[33] Volker Oschmann, *The German Renewable Energy Sources Act – Objectives, Design and Achievements*; and *What Electricity From Renewable Energies Cost*, February 2006, available from Federal Ministry for the Environment, Nature Conservation and Nuclear Safety on www.erneuerbare-energien.de.

[34] Above n 31, page 5.

Compatibility with a long-term price on greenhouse gas emissions

Feed-in tariffs are probably the least compatible with expected long-run measures if used on a widespread scale. 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 (such as generation obligations), there is little scope for the development of a contractual hedge to reduce risks. This is the case for all renewable energy support schemes. Investment will be limited unless the measure is guaranteed to exist for a specified period of time.

Other issues

A feed-in tariff may or may not be consistent with the nodal pricing system and is an important topic for discussion. Ways to simplify a feed-in tariff include using historical nodal differences to scale the feed-in tariff at different locations or using a simple nodal system – for example, with a different price for South and North Island locations. Alternatively, a guaranteed price approach – essentially a contract for differences in some form – could be used.

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 (for example, to units of energy used in setting transfer prices within a process, such as the price of heat as an input to pulp production). Germany is setting up a feed-in tariff for renewable heat.

A feed-in mechanism is often described as non-complementary to a liberalised electricity market. The electricity distributor is required to take all renewable electricity generated and to pay the generator the feed-in price. The feed-in electricity is bought and sold in parallel to the electricity market but does not directly participate in it.

Questions for discussion

13) Should capacity incentive measures be a preferred option as transitional measures?

If so:

14) Should the transitional measure be a capital grant; or a capacity subsidy mechanism such as the Non Fossil Fuel Obligation or a feed-in mechanism?

15) Do the benefits of a feed-in tariff (lower risk, new entrants, support for diverse technologies, successful deployment, industrial policy goals and simplicity of implementation) balance the way it runs in parallel to the electricity market?

16) If a feed-in tariff is preferred, what technologies should be eligible?

17) Is a feed-in mechanism compatible with New Zealand nodal pricing? If so, what policy should be introduced to link them?

18) Are some technologies more suited to capital grants than others?

19) Are there any reasons why an obligation or a capacity subsidy for certain technologies should or should not be linked?

5.5 Project based measures

General Description

Project-based schemes achieve emissions reductions by encouraging individual emission reduction actions. These abatement actions could involve emission reductions or sequestration activities. A definition of projects is that they:

- have identifiable boundaries
- include actions that can be observed, reported and verified
- have a plausible baseline against which the emission benefits of the abatement activity can be estimated
- provide an incentive – often in the form of credits – to achieve the abatement
- feature a way of excluding business as usual activities.

A project refers to a particular abatement or sequestration activity at an identifiable location that is individually managed and accounted for. Specific design elements vary from programme to programme, while meeting the properties identified above.

The purpose of developing a project-based framework is to motivate entrepreneurial efforts to reduce emissions by assigning a value to those emission reductions. In theory, awarding an incentive on a voluntarily-submitted case-by-case basis enables individual projects to achieve emissions reductions that are cost effective and real. They help to identify and initiate abatement activities and can be especially useful as a way to introduce emission price signals.

Many project-based frameworks have been used internationally. The most well known are the Joint Implementation (JI) and Clean Development Mechanism (CDM) flexibility elements of the Kyoto Protocol. Project-based activities are used to enable countries with emission obligations to receive emission units for investments in project abatement to reduce the costs of meeting their own emission responsibilities. The Netherlands Government's ERUPT programme[35] is an example of a JI project in which a country provides a monetary incentive in exchange for a future promise of emission units for 2008–2012 abatement from projects that occur in other countries that also have emission responsibilities under the Protocol (and hence an allocation of emission units).

A project not related to the Kyoto Protocol was the Australian Greenhouse Gas Abatement Programme (GGAP). The Australian government offered a large financial incentive for project-based abatement activities through a series of tender rounds. Another general type of project instrument could involve one sector of the economy (such as fossil-fuel generation) being given an obligation related to emissions that could be met by submitting project-based offset credits generation either by abatement from the same sector (such as. renewable energy) or another sector (such as provision of sink offsets). The financial incentive is provided by entities in the regulated sector purchasing the abatement credits to retire against their emission-related obligation.

A New Zealand example of a project-based framework is the Projects to Reduce Emissions (PRE) programme, which included two tender rounds in 2003 and 2004. The

[35] ERUPT – Emission Reduction Unit Procurement Tender.

New Zealand government offered a forward promise of Kyoto Protocol-compliant emission units as an incentive for near-economic abatement activities based on the expected emissions reduction the projects would deliver during 2008–2012. At least one of the firms with project agreements forward sold its expected allocation of units to the Netherlands government under ERUPT.

Incentives for project-based approaches in the energy sector could be made in two ways: firstly, by providing financial payments either upfront or after delivery of abatement; and secondly, by awarding carbon credits, as in PRE. In many respects, the two models share the same advantages and disadvantages, although key differences between the two options include the degree of involvement by firms in the international carbon market and the way in which non-delivery risk is managed in project agreements.

The financial incentive could be provided either by the Crown or by entities within a regulated sector needing to purchase credits to retire against an obligation. One example of such a scheme is the TrustPower example in Section 5.1.3, in which abatement from new renewable electricity generation could create a matching liability allocated across fossil fuel generation. This liability would require the purchase and then retirement of abatement certificates purchased either from the new renewable generation or from international markets.

Evaluation

Cost effectiveness

The cost effectiveness of project-based frameworks can usefully be broken into two key points: (i) effectiveness – the extent to which project-based frameworks reduce emissions beyond business as usual levels, and (ii) the cost of the abatement. Project frameworks can also deliver significant co-benefits, such as ‘learning by doing’ for emerging technologies and helping them to become commercially mainstream as well as contributing to electricity security of supply.

The question of whether these projects create real emission reductions – in other words, emission reductions above business as usual – is referred to as ‘additionality’. Additionality analysis includes considering whether the activity would have happened anyway (economically and considering any barriers) and, if the activity goes ahead, what impact it has on emissions (both locally and system-wide).

Demonstrating additionality is essential to ensure the programme’s environmental effectiveness[36] and to ensure that any funding is spent efficiently without supporting free riders and creating unwanted market distortions and windfall profits in industry. Additionality analysis is imprecise and will never be perfect. The 2005 Climate Change Policy Review raised some concerns about additionality and net costs to the Crown.

[36] Two options have been employed to help mitigate this concern: Additionality tests and performance standards or benchmarks. Additionality tests establish a methodology for ensuring that the reductions would not have occurred in the business-as-usual case. Performance standards ignore the question of why the emissions have been reduced and simply reward excellent performance – typically defined as performance beyond a well defined level that is stringent enough to ensure it is not a business as usual activity.

A continuing challenge is determining whether emission reductions are real and what their extent is. Greater testing rigour or higher performance standards would make it more likely that the reductions were above business as usual levels, but these tests would come with transaction costs and would have to be balanced against other desirable test characteristics (such as low cost, simplicity and administrative ease). Another approach would be to cover this risk by discounting the incentive and accepting that some non-additional proposals received incentives.

Project-based approaches are seen to be potentially cost efficient because they enable low-cost options to be developed. Once a price is established by government mandate or by participation in a tender or auction, project developers will submit projects generating reductions costing less than the set price, with lower cost offsets leading to greater profits for developers. Most project frameworks include eligibility assessment and highly contestable processes for applicants to access the incentive. The assessment processes are primarily to ensure value for the incentive provided, but usually also involves a careful risk assessment.

Offsetting this are the relatively high transaction costs than can be associated with projects. Protocols must be developed for project submission, approval and trading. Once the system is in place, an interested party must scope out potential projects, determine eligibility, submit a project for consideration and develop monitoring and verification plans as needed. Not surprisingly, this effort and expense reduces the benefit of the incentive and can eliminate some projects from consideration.

Experience with PRE indicates that transaction costs can be effectively managed, judging from the number of relatively small projects submitted (if transactions costs were too high, net benefits would be low, which would discourage participation). PRE also stimulated a large number of wind energy proposals which took this technology into the mainstream marketplace and are expected to significantly contribute to new supply.

Ease of implementation

Programmes in project-based framework designs range from the simple to the very complex. At the simple end of the spectrum, Australia's GGAP programme achieves significant reductions through only 12 independently-approved projects. Other programs, such as the CDM, are much more administratively complex.[37]

PRE was a relatively straightforward but effective example of a project-based framework, winning the Bearing Point Supreme Award for public sector innovation in 2004. It cost well under $500,000 in administration costs to run the second tender, which allocated an incentive of about $A100 million. Ongoing contract management of the portfolio of project agreements has required a little over a full-time equivalent staff member. The workload will vary through the lifetime of the agreements and will increase somewhat when abatement reporting over 2008–2012 results in the allocation of emission units. This experience will be invaluable should a successor programme be developed, whether for the energy sector alone or as a cross-sector measure.

[37] The CDM requires protocols to be approved for each project type, a detailed project design document to be evaluated, validation, registration and monitoring to be reviewed, etc (although simplified procedures are available for smaller projects).

A project-based framework uses a politically acceptable voluntary approach in which participants are compensated for reductions from the baseline rather than taxed based on their emissions. It achieves many of the same benefits as the carbon tax, but trades off administrative ease and environmental/tax funding source for political acceptability. Acceptance will also be influenced by who provides the incentive: government funding, an offset obligation on the sector, or even recycled revenues from an emission charge.

Impact on energy prices

With a project-based framework such as PRE, providing emission units to support marginally economic renewable energy projects could reduce electricity prices slightly. However, this represents a transfer of value from New Zealand's portfolio of emission units to electricity users. A programme that was similar, but in which the incentive was provided by an obligation on fossil power generation, could be expected to increase electricity prices. The extent of the price rise would be related to the ambition of the programme, but conceptually it could vary from very low to similar to that of a price instrument such as emissions trading.

Compatibility with a long-term price on greenhouse gas emissions

Project-based frameworks are a very direct and feasible way for a government to reduce emissions and are perhaps most easily implemented in the energy sector. As a price-based positive incentive measure, they are a 'carrot' rather than a 'stick' transitional measure. The monitoring, reporting and verification experiences and international carbon market engagement (in the case of PRE) are also compatible with a longer-term price instrument, such as emissions trading. The design of any specific project-based framework would affect how well it fitted in with a broad long-term price measure, but the nature of project-based frameworks represent a good starting point.

Questions for discussion

20) Are projects a climate change policy measure worth considering for the energy sector? If so, why?

21) If a project programme was to be used for energy, what part of the sector should it cover and who should provide the incentive?

22) Should the incentive be provided upfront (and with claw-back provisions for non-delivery) or subsequent to delivery of abatement (as in PRE)?

23) Are there any experiences with PRE you would like to bring to the attention of officials considering policy options for the energy sector?

5.6 Regulatory measures

General description

This section looks at direct regulatory options for discouraging fossil fuel electricity generation before 2012.

Readers should note that nearly all the measures described in this discussion paper could be described as regulatory measures. Legislation would be required to establish mechanisms supporting any emissions trading scheme, carbon charges or other systems. However, this section describes direct regulatory (or mandatory) options that could complement or serve as policy alternatives to those other measures.

In the absence of an economy-wide price on greenhouse gas emissions, a direct regulatory measure could specifically target new investment generation to ensure it was lower carbon than business as usual.

Any regulatory measures would be limited in direct application to new fossil fuel power plants. The measures would indirectly encourage new renewable energy by having an impact on the operational and infrastructural costs of fossil fuel plants and increasing electricity prices.

Examples of regulatory measures, standards or requirement on new fossil fuel (or just on new coal) that could be introduced include:

- a mandatory emissions-offset requirement for new generation (which could also be linked to emissions trading, as in section 4.1.3). The requirement could be for afforestation or geological emissions sequestration (carbon capture and storage, or CCS) to match some or all emissions from new fossil generation
- a requirement to be ready to use CCS when the technology became economically viable and practical; and/or to adopt emissions standards for new fossil fuel plant.

CCS involves the use of technology to collect and concentrate the CO_2 produced from industrial and energy-related sources, transport it to a suitable storage location, and then store it away from the atmosphere for a long time.

Compared to conventional generation, CCS could allow fossil fuels to be used with 80-90 percent lower emissions of greenhouse gases. However, CCS would raise energy costs. The technology is in its infancy and cost estimates are premature. In addition, there are a number of uncertainties associated with the development of an appropriate regulatory regime to deal with sequestration.

Once the regulatory measure is decided upon, the next issue would be the method of implementation. Two pieces of current legislation are explored: the Electricity Act 1992 and the Resource Management Act 1991 (RMA).

5.6.1 Using the Electricity Act 1992

The Electricity Act 1992 could be amended to enable the introduction of regulations controlling fossil fuel stationary energy generation.

Developing a carbon capture or offset requirement policy would require an overseeing/administering body. This would preferably be an existing body such as the Ministry of Economic Development, the Electricity Commission or the Ministry for the Environment.

This approach could be tied into any regulatory changes considered under the NZES and other energy sector work programmes.

5.6.2 Using the Resource Management Act 1991 (RMA)

The RMA provides various opportunities for central government to intervene in resource management policy and/or regulatory decision-making that is otherwise devolved almost entirely to local government.

These include issuing National Policy Statements (NPS) and National Environmental Standards (NES), and making specific responses to individual projects. These responses include:

- calling in applications for resource consent, notice of requirement or requests for private plan changes or regional plans
- making submissions on behalf of the Crown
- appointing a project co-ordinator for an application for resource consent to advise a local authority
- directing that a joint hearing be held if more than one authority is involved
- appointing a hearings commissioner in cases where a local authority has decided commissioners should hear an application.

There are other ways for the government to influence decision making that are not specifically provided for in the RMA or which are not specific to the government. These include issuing non-statutory guidance and making submissions on plans, consent applications and notices of requirements for designations.

The government can use an NPS or an NES in matters of national significance at stake and where it can be demonstrated that they are the most appropriate mechanisms having regard to their efficiency and effectiveness. Before adopting an NPS or an NES, the government must carry out an evaluation to demonstrate that the statutory cost benefit tests of section 32 of the RMA are met.

Under the current wording of the RMA, if the government wanted to use it to reduce or manage greenhouse gas emissions from large direct emitters, an NES would be the only effective national policy instrument. An NPS would not be effective alone because it does not contain rules and methods and has no direct effect on consents. An amendment to the RMA would be required.

If the RMA was amended to empower local controls on greenhouse gas emissions because of their effect on climate change, councils could use rules in plans and conditions on resource consents, applied locally on a case-by-case basis. The government would then also be able to use ministerial powers of intervention.

National Policy Statements

As stated above, the RMA would have to be amended to implement an NPS that enabled local controls on sources of greenhouse gas emissions because of climate change impacts. This section assumes such an amendment is made.[38]

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[38] Note there is a Member's Bill to remove the restriction on plans and consents dealing with impacts of discharges on climate change currently before the Local Government and Environment Select Committee.

NPSs state objectives and policies for matters of national significance that are relevant to achieving the purpose of the RMA. NPSs can set out objectives and policies that local authorities must “give effect to” in their local and regional policies and plans, and which they must have regard to when making decisions on individual development projects.

As a result, there are two primary tests to be assessed by stakeholders. The first is whether encouraging or discouraging particular electricity generation types are, or could actually or potentially affect, a matter of national significance (see RMA Part 2 and s45(2)).

The second is whether an NPS could state policies in relation to electricity generation that address the issues associated with that activity and do so in a way that promotes the sustainable management of natural and physical resources as defined in section 5 of the RMA.

NPSs can influence both the local and regional policy environment, and the outcome of resource consent decisions on individual development proposals. NPSs do not, however, have the same direct or immediate effect as a regulation (or NES). Their effect will only be felt when a resource consent application (or designation) is required or when a local authority’s district or regional plans are changed to give effect to the NPS.

An NPS on electricity generation could cover some or all of the following issues:

- a range of detailed issues associated with each generation type (such as water allocation, discharges to air and water, landscape impacts and noise)
- issues relating to the development of renewable electricity generation
- generic issues with the way that electricity generation is managed under the RMA.

An NPS relating specifically to controlling greenhouse gas emissions from electricity generation could be combined with elements of an NPS on generic electricity generation issues.

It is unclear whether the marginal benefit to be derived from such a policy could be outweighed by the risks associated with unintended consequences and regulatory creep. Unintended consequences are the uncertainties about the impact the policy could have, and concerns that it could have an effect that has not been anticipated or desired. Concerns about regulatory creep are that the process of developing the NPS could lead to its scope being expanded beyond the minimal high level policies proposed.

National Environmental Standards

An NES is a regulation that prescribes technical standards, methods, or requirements in relation to the control of land, the coastal marine area, the beds of rivers and lakes, discharges to water or air, and noise. NESs are regulations that can over-ride local and regional rules. They can specify the performance standards required in relation to specific activities, or specify what category of resource consent should apply at local or regional levels.

NESs may:

- prescribe the outcome or level of performance expected from certain activities
- prohibit an activity
- permit an activity that does not have a significant adverse environmental effect, subject to any terms and conditions specified in the standard or in any plan
- allow an activity subject to a resource consent (including prescribing the consent category that applies, such as whether local authorities should regard the activity as controlled, restricted discretionary, discretionary or non-complying).

The first suite of NESs has recently been prepared for certain air quality matters, including standards in relation to dioxin and other toxics, ambient air quality, the design of wood burners and the control of landfill gas.

NESs do not need to be translated into a regional policy statement or plan before taking effect. However, as noted above, NESs can require local authorities to regulate activities in prescribed ways. In such cases NESs may be translated into rules in plans. Rules and resource consents cannot be more lenient than an NES. They can, however, be more restrictive than an NES if the NES specifically provides for that. Even where an NES exists, plans may continue to have a role specifying the requirements that apply to activities that are the subject of an NES.

NESs can also require the conditions of water, coastal and discharge permits to be reviewed. When conditions are reviewed, the NES prevails over whatever conditions applied prior to that review.

In theory, an NES could be applied to particular detailed issues such as noise from wind turbines, methodologies for landscape assessment and management of discharges from fossil fuel stations.

Evaluation

Environmental effectiveness and impact on energy prices

Without the specifics of a particular regulatory measure, it is very difficult to evaluate the impact on prices and environmental effectiveness of particular measures because they depend on the stringency of the measure and the specifics of what is being regulated for. However, in general, any regulatory measures are likely to result in increased cost to generators. This may raise electricity prices, but it is also likely to result in displacement of greenhouse gas emissions over time as a result of an increase in renewable generation.

It is unclear how environmentally effective an NPS (with RMA amendment) or an NES would be. A simplistic assessment might conclude that an NES, by prescribing outcomes and technical limits, would be better than an NPS, which gives local authorities some discretion over consent conditions. However, such a weakness is corrected by accompanying any NPS with NES and other guidance documents.

Cost effectiveness

Again, it is difficult to assess the cost effectiveness of introducing regulatory measures without precise details of the measure.

An NES is the least costly option because it does not require legislative amendment. However, it should be noted that, because all the RMA options devolve decision making to the local level, except when appealed to the High Court, costs are also transferred to the local level. NESs are subordinate legislation and there are costs of development and consultation.

One possible NES objective could be to ensure large emitters of CO_2 participated in a trading system. At this early stage of assessment, it is difficult to determine whether a NES is actually needed for this purpose, whether such a purpose goes beyond the bounds of what an NES can do, or whether participation would be guaranteed through the legislation that sets up the mechanism itself.

All the RMA options have a degree of ‘double jeopardy’ risk, where national measures might be implemented on top or in support of resource consent conditions.

Ease of implementation

CCS and offset regulatory measures are unlikely to be easy to implement. In particular, an amendment to the Electricity Act 1992 would require considering complex monitoring and enforcement requirements.

Both the NPS and NES options devolve decision making to local authorities. This introduces risks regarding consistency between regions, costs to all parties and litigious processes. It is debatable whether any RMA measure would provide clarity and certainty for all parties, as the RMA consenting process is open and risky, particularly for large projects such as a new fossil fuel power plant. However, there is less room for local variation in consenting issues through an NES than an NPS. This is because a NES has direct effect and the rules are standard across the country, while an NPS has to be implemented through plans and consents with inevitable room for local variation.

A NPS would be the least practical option because it would probably take a long time to develop and implement. It is highly likely that such a measure would need the development of national guidance, such as an NES.

An NES could be easier than an NPS to develop and to implement, created using existing powers, and written to have an impact only on new fossil fuel generation plants. It could also be written so that controls were consistent between regional authorities.

Compatibility with a long-term price on greenhouse gas emissions

The measures might not be incompatible with long-term measures, providing the regulatory requirements and time frames are clear and certain.

For measures with an element of trading, such as emitters fulfilling resource consent requirements through direct participation in an emissions trading system, the regulation could simply transfer to a broader long-term trading measure.

Questions for discussion

24) What impact would you expect regulatory measures to have on energy prices?

25) What impact would you expect regulatory measures to have on security of electricity supply?

26) In addition to the measures discussed in this section, are there examples of regulatory barriers that need to be identified?

27) What activity should an NES target?

5.7 Voluntary measures

Voluntary measures typically refer to measures that are undertaken through agreement rather than mandated through direct legislation or financial incentives and penalties. However, voluntary measures could be the object of regulation where the participation in a commitment scheme is mandated by legislation. Several of the options discussed previously in this paper could be undertaken on a voluntary basis.

An example of a voluntary measure could be a written agreement between the government and the generator that would define the targets, the period and nature of the measure. The targets could be specified in terms of absolute greenhouse gas emissions in each year, emission intensity, or energy efficiency. Less direct measures are also possible, such as assurance that best available technologies are being used or that a marginal shadow price for CO_2 emissions is being incorporated into decision-making.

A wide range of processes and tools could be used for establishing a target. For instance, target setting could be by negotiation between the Crown and the participant firm or sector, through an energy audit and an agreement to implement cost-effective measures, or through a requirement to meet some standard of best practice for the participant's plant.

A voluntary agreements scheme could feature:

- agreed targets and public reporting of performance against targets
- mandatory consequences for non-performance against targets, with limited stringency
- limited pilot emissions trading and other flexibility mechanisms, facilitated by the government
- assurances that participation in the scheme would not disadvantage participants for the later price-based measure (in other words, that any grandparenting approach for emissions trading would be based on performance prior to entry into the agreement)
- mandatory monitoring, reporting and verification of emissions for generators participating in the scheme and for those who are not participating.

Evaluation

Environmental effectiveness

It is difficult to ensure environmental effectiveness with voluntary measures. Voluntary initiatives can significantly reduce greenhouse gas emissions in some situations, but empirical evidence of voluntary approaches often shows they are most effective when implemented in association with a regulatory consequence if no progress is achieved. Such measures, although they are likely to produce results, then start to closely resemble several of the instruments already discussed in this paper.

Cost effectiveness

Negotiating individual performance agreements that assessed specific generation sites and performances would be a difficult, costly and drawn-out process for all parties. An early conclusion would be that voluntary agreements would not represent a cost-effective approach to achieve the objectives of this work programme.

Ease of implementation

See above analysis of cost effectiveness.

Compatibility with a long- term price on greenhouse gas emissions

If entry into a programme and acceptance of a commitment are both voluntary, generators would need to be motivated to participate. A possible incentive could be a connection to any longer-term price measure. For example, subsequent allocation decisions could recognise voluntary targets or achievements. Generators that participate and meet their commitments could be assured their allocations would be based on a different formula or based in some way on their monitored achievements.

From a different point of view, this may be regarded as credit for early action – a framework for participants to record achievements to ensure that subsequent allocations do not penalise actions taken before the allocation decisions are made.

Questions for discussion

28) What process should be used to develop voluntary agreements for generators?

29) Can voluntary agreements be used as an effective tool to make the transition to long-term price-based measures?

6 Summary for Discussion

The previous sections presented a range of options to enable the stationary energy sector to move towards a low emissions energy supply and to enable a transition to greenhouse gas pricing. Each of the options would contribute to these broad objectives. They differ in a number of important aspects, including their likely effectiveness, cost efficiency and who would bear the costs of the change in behaviour – the taxpayer, the emitter or the electricity consumer. A summary of these effects is presented in table 3. The attempt at ranking options against the different criteria is indicative and provided only as a means of summarising previous discussion.

Key questions

Three key questions need to be asked to determine a preferred option or mix of options.

1. What key objectives should steer the choice of transitional measures in the stationary energy supply sector?

The draft NZES identifies a number of objectives, including making greater use of our abundant renewable energy resources, reducing our greenhouse gas emissions, promoting cost-effective environmentally sustainable technologies, and maintaining high levels of security and reliability at competitive prices. While these objectives are in general complementary, there may be some trade-off decisions to be made.

Perhaps the most relevant examples are whether the focus in the near term could be to increase the proportion of energy supply from renewable sources, or to achieve low emissions energy supply at least cost. In the case of the former, the most effective policy options may well be incentives or renewable obligation options. In the case of the latter, price-based measures such as emissions trading and CO_2 charges could be more appropriate.

Price-based measures such as emissions trading and CO_2 charges are technology neutral. They set a price and let the market determine the most cost effective mix of energy supply based on this additional cost. A disadvantage of price-based measures is that you cannot be sure of the outcome. With price based measures for example, there is no certainty that there will be no new investments in coal fired power stations (although it is a less likely outcome than if there was no price-based measure). Incentive measures, targeting specific technologies, or direct regulatory approaches can potentially give greater assurance about the sources of future energy supply, but are less likely to be cost effective and may end up imposing higher costs on consumers.

2. Who should bear the costs of the measures – emitters, consumers or the government?

The power generation sector can and generally will pass on costs to consumers through higher energy prices. Industrial sources of heat and power may be more constrained in passing on costs.

In keeping with the “polluter pays” principle and the concept of economic efficiency, those responsible for emissions should pay for them. However, there may be reasons why the government wants to step in and give financial support for initiatives. In the case of the electricity sector, this may be justified to avoid any substantial increases in energy prices for consumers and/or industrial users. Subsidies for renewable programmes would be likely to reduce overall energy costs.

3. Certainty of price or certainty of outcome?

Some measures give greater certainty about the level of price impacts, whereas others give greater certainty about the outcome for emissions. A CO_2 charge, for example, gives emitters certainty about the cost of greenhouse gases, but the level of emissions abatement is uncertain. A cap and trade system gives relative certainty about how much emissions will be reduced by, but less certainty about the cost of greenhouse gases to emitters. Renewable obligations can give relative certainty about how much more investment will be made in renewable energy, but costs remain uncertain.

Table 3 presents a summary of options presented in this paper (with the exception of voluntary measures).

Table 3: Summary of Effects (1 is least positive and 3 is most positive)

	Price based measures											
	Emissions trading				CO_2 charge	Renewable obligations		Incentives			Direct Regulatory	
	Cap and Trade	Baseline and Credit	Trading of cross sectoral offsets	Trustpower proposal	CO_2 charge	Capacity obligation	Generation obligation	Capacity subsidies	Feed-in tariff	Projects	Using Elect city ACT city Act	Using RMA
Environmental effectiveness	3	2	2	2	2	2	2	2	2	2		
Cost effectiveness	3	3	2	2	3	2	2	2	2	2		
Ease of implementation	1			2	2	2	3	3	2	2	1	1
Compatibility with a long-term emissions price signal	3	2	2	2	2	2	2	1	1	2	1	1
Impact on energy prices												
Price falls				*[39]							*[40]	
Price increases												
Potential coverage												
Electricity												
Industry (heat)												
Industry process emissions												
More renewables entry												
Less fossil fuels entry												
Who bears the cost												
Crown/taxpayer												
Emitter/consumer												

39 *Thermal entrants may lead to a higher electricity price.

40 *Prices may rise or fall depending on the nature of the regulation.

Principles for deciding on options

In the draft NZES, the government proposes a number of principles to guide the choice of transitional measures. These are:

a) Measures should be compatible with, and enable a transition to, longer-term policy options where the cost of greenhouse gas emissions is reflected in the relative cost of the fuels that produce greenhouse gas emissions.

b) Investors in new generation should face a price signal that reflects the value of greenhouse gas emissions avoided for renewables relative to fossil fuels, either immediately or over a transitional period.

c) Owners of existing fossil fuel generation should follow a transitional path to facing the full cost on greenhouse gas emissions.

d) On electricity prices, the effect of any transitional measures on electricity prices should be gradual.

Based on the above principles, the government is attracted to measures which would support the early development of emissions trading in the sector.

Further issues for consideration

Competitiveness issues

Generation of electricity in New Zealand is characterised by high levels of renewable energy sources. As a result, the emissions intensity of New Zealand grid electricity is low compared to electricity consumed in many major trading partner countries. This reasoning implies that a price on emissions from electricity generation would potentially have a relatively low impact on the wholesale price of electricity supplied in New Zealand, although the extent of the impact depends on whether the price on emissions is applied to marginal or absolute emissions, and whether the wholesale clearing price of electricity is determined by fossil fuel or renewable generation.

Treatment of industrial process emissions

Industrial process emissions do not fall within the scope of this discussion paper (as they are not covered in the scope of the draft NZES). However, as illustrated in Table 3, many of the options discussed in this paper could be extended to cover industrial process emissions, which could be desirable in terms of climate change policy and efficiency.

Market power issues

As a relatively small island economy with no electrical connections to other countries, New Zealand can avoid some of the implementation complexities that would be encountered elsewhere. However, the small size of the New Zealand market, combined with the relatively small number of market players, make market power a critical issue for consideration when any transitional measures are designed. For example, the electricity generation market is dominated by only five companies. Careful attention will need to be given to the design of market rules to assure that these measures foster competitive behaviour.

Taking account of other existing or proposed policies

Any mechanism that gives electricity and industrial emitters an incentive to use renewable energy should take any other existing or proposed policies into account. As an example, the government is developing a biofuels sales obligation that penalises oil companies if they do not sell a proportion of biofuels. The level of biofuels that is used to meet this obligation, or contribute beyond this obligation, might be affected by any future incentives/disincentives to use the biofuel in industrial heat or electricity production.

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