Availabilities and Costs of Renewable Sources of Energy For Generating Electricity and Heat

Report to the Ministry of Economic Development

By East Harbour Management Services Ltd

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1. SUBJECT OF THIS REPORT

1.1 Background to the Report

The Energy Modelling and Statistics Unit of the Ministry of Economic Development (MED) sought to review the assumptions underlying the Ministry's current estimates on the availability and costs of generating electricity and heat from renewable energy. Renewable energy (biofuel) for transport has been excluded from this review. The review was to be based on existing published documents where appropriate, and where more recent information was readily available, the estimates were to be updated.

The revised estimates focus on the period up to 2012 but also look beyond this to give a view on the position out to 2025.. No account is taken of possible carbon charges or renewable energy credits, so the uptake scenarios represent a "Business as Usual" case.

This study focuses on the renewable resources and technologies that are likely to find reasonably widespread application by 2012, a year significant as a Kyoto Protocol milestone. The criterion given for the review was that technologies should have the potential for generating electricity at a cost less than 15c/kWh (2002 dollars), or for heat at less than $25/GJ.

In particular, the study looks at hydropower, geothermal, wind power, woody biomass, landfill gas and other biomass energy sources, and solar water heating. Photovoltaics have been included for completeness and because it is likely that by 2025 this technology will have become more economically competitive with the previously mentioned renewable technologies, or isolated diesel plant at the retail end of the market.

The study updates data originally presented in the May 1993 Ministry of Commerce report "Renewable Energy Opportunities for New Zealand". This report was subsequently updated by a July 1996 report jointly published by EECA and Centre for Advanced Engineering (CAE) entitled "New and Emerging Renewable Energy Opportunities in New Zealand". Further technology-based reports have been produced in the last two years, including three reports published by EECA focussing on wind, biomass and solar opportunities. Where possible, the updated data has been based on these later reports.

A brief outline of each type of resource and associated technology has been provided in a form similar to the Summary Data Sheets included in the 1993 report. The information in the data sheets has been updated to reflect an assessment of current community, social, and environmental values.

Information has been prepared covering electricity and heating as appropriate. The resource availability takes no account of electricity transmission/distribution constraints, which are assumed to be addressed when required.

Resource availability in 2012 (and beyond) has been outlined, disaggregated costs have been provided, then aggregated costs developed in tight bands to enable ready use in energy modelling. In addition, assessments have specifically been made for the year 2025. Confidence levels have been applied. The resulting supply curves show additional potential over that which is currently used.

1.2 Comment on Estimates

The cost and quantity information in this review is based on a wide range of publicly available sources. In many cases the specific information has had to be generalised in order to produce realistic cost curves relating to the likely availability of each renewable resource.

The reviewers have used a number of published sources of information plus undertaking original analysis where the published information is considered no longer applicable. Consultation with a number of specialists has been undertaken to ensure that unpublished information is incorporated wherever possible.

The report is not just an indexing revision of the unit costs of each technology. Since 1993 there have been some significant changes in the technologies and in a number of cases a paradigm shift in the conceptual thinking about the resource and its utilisation. The report incorporates these significant changes in thinking.

The boundaries of the review have been constrained by the perceived realities of uptake for each of the technologies in the period up to the year 2012 and on to 2025. In the discussion on each technology comments have been included on the constraining factors and issues that will need to be addressed in order to increase uptake. These do not include an exhaustive analysis on each technology. The comments made provide guidance to the priorities for further work.

The extrapolation of specific information to provide generalised cost curves is based on the experience and opinions of the reviewers.

The report addresses the issue of uncertainty by placing the energy quantity estimates into a number of confidence classes or bands.

All costs are in 2002 dollar values. An estimate has been made of real cost changes that may occur over time[1] and these cost reductions have been applied when estimating availabilities for 2012 and 2025.

The real changes in capital costs may arise from economies of scale, advantageous exchange rate changes, increased experience and technology changes.

1.3 Confidence Bands

To provide some guidance on the applicability of the resource estimates the following definitions are given.

High Confidence: These resources are well proven resources, assessed as readily able to be permitted and developed. Achievable development rate has been taken into account. They represent an 80-90% confidence that the uptake will occur.

Medium Confidence: These estimates represent an intermediate resource estimate, for the most part a median estimate of uptake. Generally these are associated with a more liberal consenting environment. Achievable development rate has been taken into account.

[1] Exchange rate changes have also been taken into account. MED modelling assumes that the current exchange rate of US$0.42=NZ$1 will rise to US$0.50=NZ$1 by 2006 and this has been used in determining costs.

Low Confidence: These resources can be developed but difficulties are expected in terms of permitting and access. They represent a 10-20% confidence that the uptake will occur.

Where confidence levels are discussed in this report, these levels are cumulative (except where otherwise noted) e.g. the medium confidence resource available will include both the high and medium confidence bands, low confidence resource available will include high, medium and low confidence bands.

2. RENEWABLE ENERGY PACKAGES

2.1 Package Selection

The renewable energy options considered in this report were based on the Ministry of Economic Development's view of those technologies with the greatest potential for uptake. The reviewers believe this reflects a sound commercial selection.

The following table lists the selected renewable packages, and emphasises alternative uses of the resources. Several have the ability to supply heat, a major component of the national energy mix.

Table 1: Selected Renewable Packages and their Potential Uses

Resource	Electricity	Heat	Other Uses
Hydro	Yes	No	Irrigation (non-energy)
Geothermal	Yes	Yes	Minerals (non-energy), tourism
Wind	Yes	No	Minor recreational transport
Biomass (Woody)	Yes	Yes	Potential fuel source for transport, feedstock (non energy)
Biomass (Landfill Gas)	Yes	Yes	Potential fuel source for transport, feedstock (non energy)
Biomass (Other)	Yes	Yes	Potential fuel source for transport, feedstock (non energy)
Solar	Yes[1]	Yes	Off grid energy

1. The solar discussion focuses on demand-side management through solar hot water heating and electricity generation from photovoltaics.

The report focus is on the potential major contributors to a renewable energy future. Other renewable options, such as air and ground-source heat pumps will play a part in the future, but much research and development and then public education will be required to bring these into widely accepted commercial application. Future reports will be able to include these technologies as they move through their development phases, but for now they are omitted from this report as being too expensive and of limited extent.

Wave and tidal options have also been omitted from this report. Wave power developments in other countries have met with notable failures in recent years. NIWA has continued to research the potential resources around New Zealand's coastline. Some uptake may occur in future but will have to await renewed investor confidence on the international scene.

For discussion on each of these renewable resources and the associated technologies refer to the Summary Data Sheets of Appendix A. For further details, refer to the Data Reports of Appendix B.

2.2 Technological Status

As a rule, the technologies considered here and used for modelling may be considered as proven or commercial. Biomass gasification should be commercial in the timeframe of this report. Research and development, and prototype development is occurring in a number of areas (e.g. biomass pyrolysis) but these aspects have been omitted from consideration as cost projections inevitably have a high optimism factor.

Hydro and geothermal energy are both proven technologies. Having said that, changes are occurring in the design concepts. In the last 10 years a hybrid steam-binary cycle geothermal development has been proven (with applications in New Zealand), and improved designs for large geothermal condensing turbines have caused a price drop in real terms. While hydro technology is proven, some novel thinking has been demonstrated in Lower Waitaki River proposals for example. Lateral thinking such as this can lead to marked changes in development costs over those projected in this report.

One of the most notable advances in the last 10 years has been the development of wind energy. Capital costs have been dropping as worldwide uptake of this resource has accelerated and the technology has matured. This is now seen as being a significant contributor to New Zealand's energy future during the period under consideration with reliable performance in both technology and financial terms.

2.3 Renewable Energy Quantity Estimates

Resource quantity estimates have been based on recently published data. These cover resources for both heat and electricity. The resource assessments are approximate but represent considered views. The basis for these estimates is outlined in the respective resource reports (Appendix B).

The reviewers have developed a view on the uptake of resources. This has taken into account a wide range of factors including:

- Elimination of resources that will exceed 15c/kWh in terms of electricity supply cost, or $25/GJ for heat supply cost,
- Elimination of bulk generation opportunities that are remote from the grid, or in environments for which consents will not be obtained,
- Inclusion of distributed energy opportunities,
- Practicality of building or installing the options, and
- Previous expressions of interest/commitment (e.g. consent applications) by potential developers.

In the case of biomass, the opportunity for the supply of heat has been recognised to a limited extent, and a split has been indicated between supply for electricity and heat. In practice, heat supply may substitute for electricity generation or vice versa.

An assessment has been made of the current use of each resource. Where necessary, this current use has been subtracted from the total assessed resource to give potential uptake by 2012 or 2025 over and above the current usage. In other words, the energy potential given in this report represents potential uptake over and above the current datum.

Confidence levels have been applied to assessments as discussed above. The intention of these estimates is to outline a range of developments that are realistically fundable, consentable (in a positive policy environment) and buildable in the timeframes set by this report. Wherever possible, blue-sky options have been eliminated to give a focussed commercial view. However, a range of projections is possible and these have been rated from high to low confidence.

In some cases, resources have been calculated on a regional basis. However, the Ministry of Economic Development economic model, to which this report inputs, does not include regional effects so national aggregated totals are given in the following table. (Further detail may be found in the individual resource reports).

The following table summarises the assessed resources complying with these conditions.

Table 2: Potential Resource Available (Primary Energy Basis) at less than 15c/kWh (Electricity)/~$25/GJ (Heat)[1] (PJ/y)

Resource	2012			2025		
	High Confidence[2]	Medium Confidence	Low Confidence	High Confidence	Medium Confidence	Low Confidence
Hydro	21	41	65	21	41	65
Geothermal[3]	83	160	710	196	319	710
Wind	15	34	49	15	36	51
Biomass (Woody)	6	21	73	12	28	91
Biomass (Landfill Gas)[4]	8	8	8	8	8	8
Biomass (Other)	-	-	-	-	-	-
Solar[5]	NA	NA	NA	NA	NA	NA

1. Cost is related to a WACC of 10% for both electricity and heat. See later comments about the limit on heat price. Other factors influencing assessment include elimination of remote sites or sites for which consents will not be obtained, practicality of installing options, previous expressions of interest/commitment, current utilisation
2. Confidence is treated cumulatively e.g. medium confidence resource includes that available with high confidence
3. Geothermal energy has been converted back from GWh/y using a resource conversion efficiency of 10%
4. Landfill gas energy has been based on the total resource less current generation converted back from GWh/y using a conversion efficiency of 36%
5. Solar resources are large but constrained by uptake scenarios.

Table 2 indicates the greatest potential resource for supply of renewable energy is geothermal followed by hydro and wind, then followed by woody biomass. Other technologies will make a contribution, although their overall impact will be minor. This does not diminish the potential of solar and other biomass contributions.

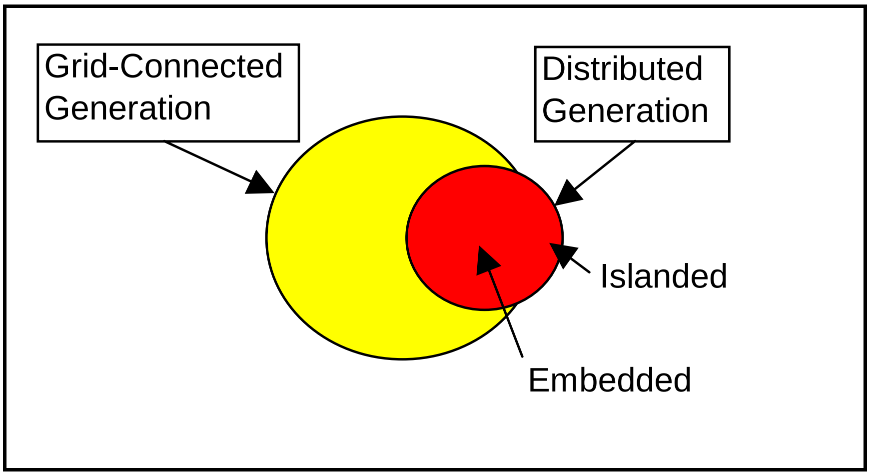
3. ELECTRICITY GENERATION

3.1 Grid-Connected, Embedded and Islanded Generation

For a detailed discussion on grid-connected and distributed generation options and the paradigm shifts that have seen a recent proliferation of distributed generation, refer to Appendix C.

Broad relationships between the various generation options are shown in Figure 1. Renewable energy options can make a contribution within any of these areas.

Figure 1: Relationship Between Generation Options



Grid-connected Generation

Any generation that is synchronised to the grid can be said to be "grid-connected". Thus a small photovoltaic cell on a home may be grid-connected.

Islanded Generation

Islanded generation refers to generation that feeds a load that is either not connected to, or which has been disconnected from (or is remote from) the local electricity grid or network. These systems can function well, as long as the equipment supplied by the generator has been appropriately designed for the delivered voltage and frequency (even a direct current supply is possible). Examples could include a remote farm, or a company that has made a strategic decision to operate on its own supply and operates disconnected from the grid. In these applications there is no interaction between generation, load and the national grid. A risk is introduced in that generator outage (if not supported with backup generators) will result in failure of electricity supply with resulting effects on factory/business operations.

A grey area exists where the load can be either grid-connected or islanded. Examples of this include use of backup generators in hospitals, prisons, factories, hotels or pumping stations.

In the short to medium term, islanded generation is expected to be only a small contributor to the national electricity supply. Where it can be used to progressively isolate a site from the grid, it can have an impact on peak load management and can affect peak price on the spot market if on a sufficient scale.

Embedded Generation

Generation can be connected to the grid at a range of levels, each with their own costs and benefits.

Traditionally, large power stations have directly fed into the national grid through a dedicated substation (Grid Injection Point) at transmission voltages. Generation is generally too great to be absorbed by the local network company's system. This would not normally be considered embedded generation.

Many of the renewable energy options are in the 5 to 100MW class. Depending on location, there may be opportunity to feed this directly into the network company's system. There is a potential match between many of the renewable generation options and local network demand allowing embedded generation. The lower voltage associated with embedded generation can make better use of existing transformers or lead to a lower cost transformer.

Embedded generation will help to offset losses and capacity constraints associated with transmission and distribution of electricity. There may be opportunity to be rewarded for this system service.

In some cases, generation may be installed in a factory, office or home. In some cases this electricity generation would be simply netted off the load. In other cases it may be sold back to a retailer (usually one that supplies the load) through the network company's system. Benefit would be site-specific and a strong function of the local tariff structure offered by the site electricity retailer (including any pass through or other basis for pricing lines charges).

General Comment on Embedded Generation within this Report

Capital costs used in this report for the various electricity generation options are those associated with the appropriate level of grid-connection. Because of their size, some of the renewable generation options will be embedded. These and other factors have been fed into the cost supply curves.

The uptake of some renewable generation will be a strong function of the network companies' desire to accept (and both the network and retail companies willingness to promote) distributed/embedded generation through appropriate tariffs and/or investment.

3.2 Renewable Resource Development Costs

All projections in this report are based on generic costs, or cost estimates which have been published previously. As projections, they are subject to considerable uncertainty (±30% would be expected for any one project). However, because these estimates are based on past developments, they have been checked with industry trends, and are across many projects, the overall result is considered to be reasonable.

Capital costs are discussed in the resource reports (Appendix A and B). A wide range of cost sources has been consulted. Values associated with most confidence have been converted into New Zealand dollars of the time of the estimate. These have then been escalated to current dollars.

Operations and maintenance costs have been estimated on a similar basis. As a rule, O&M can be considered to be largely fixed with little variable component for the range of applications considered here.

Exchange rate costs have an impact on the cost of imported components. This affects both capital and maintenance. Assessments have been made of the proportion of the total cost that may be affected by exchange rate changes.

For a detailed description of the derivation of the capital and Operations and Maintenance estimates, refer to Appendix D. Appendix D also outlines the inputs into unit cost modelling. Unit cost modelling was carried out with a weighted average cost of capital (WACC) set at 5% and 10% as requested by the Ministry of Economic Development. A comprehensive set of estimates for each WACC and confidence level has been derived and is given in the resource reports (Appendix A and B). These have been used to develop the cost supply curves.

Table 3, based on the discussion in the resource reports, shows the assumed relationship between generator size, capital cost and O&M for each technology.

Table 3: Cost Estimates for a Range of Resources

Resource	**Capital Cost Estimate**	**O&M Estimate**
Hydro	Highly variable - no clear size relationship - typical current costs $1,500-$8,000/kW, mean cost $3,600/kW	About $15/kW/year.
Geothermal	Plant is modular with economies of scale (25MW plant currently at $3,200/kW, 50MW plant at $3,000/kW). These can be partly offset by presence of existing Crown wells. Binary plant is more expensive.	Station/steamfield O&M about $93/kW/year for stations >50 MW. “Fuel” costs are included in the capital and O&M figures above.
Wind	Typically current specific cost is around $2,000/kW and largely independent of size due to modular nature	O&M Fixed $28/kW/year and variable $0.006/kWh.
Biomass (Woody)	Technology is assumed to be Atmospheric Biomass Gasification Combined Cycle. Electricity cost in 2012 ($/kW) = 8,950 x MW $^{-0.2673}$ Electricity cost in 2025 ($/kW) = 7,360 x MW $^{-0.2673}$	O&M 5% of capital/year.
Biomass (Landfill Gas)	If collection costs are included specific cost is $2,250/kW. If they are excluded, cost is $1,500/kW	O&M $70/kW/year.
Biomass (Other)	These costs are not discussed as they are excessive.	
Solar Hot Water Heating	Capital costs are dropping. Equivalent to $2,500/kW by 2012	O&M $35/unit/year.

The unit costs used in this study are levelised unit costs for each project life. For a project this unit cost is derived by taking the present value of costs, i.e. capital, O&M, tax, depreciation (including tax benefits of depreciation), fuel (where applicable), and dividing it by the present value of the kWhs generated over the lifetime of the project. No revenue stream is included in this calculation.

3.3 Renewable Resource Availability Estimates

A key output of this report is an assessment of resource availability. The total resource on a primary energy basis was outlined in Table 2 of section 2.3. Detailed discussion is given in Appendices A and B. To obtain estimates of resource availability on a consumer energy basis, the conversion efficiencies associated with each relevant technology have been applied (details are given in Appendix D). Tables 4 and 5 below give the resulting resource availability estimates.

Table 4: Potential Resource Available (Consumer Energy) at less than 15c/kWh[1] (MW)

Resource	2012			2025		
	High Confidence[2]	Medium Confidence	Low Confidence	High Confidence	Medium Confidence	Low Confidence
Hydro	1,105	2,235	3,610	1,105	2,235	3,610
Geothermal	290	565	2,510	690	1,130	2,510
Wind	1,550	3,610	5,150	1,695	3,955	5,650
Biomass (Woody)	20	200	970	40	270	1,190
Biomass (Landfill Gas)[3]	13	13	13	13	13	13
Biomass (Other)	-	-	-	-	-	-
Solar	NA	NA	NA	NA	NA	NA

1 Cost is related to a WACC of 10%. Other factors influencing assessment include elimination of remote sites or sites for which consents will not be obtained, practicality of installing options, previous expressions of interest/commitment, current utilisation
2 Confidence is treated cumulatively e.g. medium confidence resource includes that available with high confidence also.
3 Landfill gas resource confidence is high but there is later discussion about the price.

Table 5: Potential Resource Available (Consumer Energy) at less than 15c/kWh[1] (GWh/y)

Resource	2012			2025		
	High Confidence[2]	Medium Confidence	Low Confidence	High Confidence	Medium Confidence	Low Confidence
Hydro	5,940	11,370	17,990	5,940	11,370	17,990
Geothermal	2,310	4,450	19,750	5,440	8,880	19,750
Wind	4,095	9,550	13,645	4,285	10,005	14,300
Biomass (Woody)	140	1,415	6,225	285	1,910	8,420
Biomass (Landfill Gas)[3]	100	100	100	100	100	100
Biomass (Other)	-	-	-	-	-	-
Solar Hot Water	210	260	300	530	540	660

1 Cost is related to a WACC of 10%. Other factors influencing assessment include elimination of remote sites or sites for which consents will not be obtained, practicality of installing options, previous expressions of interest/commitment, current utilisation
2 Confidence is treated cumulatively e.g. medium confidence resource includes that available with high confidence also.
3 Landfill gas resource confidence is high but there is later discussion about the price.

3.4 National Electricity Supply Curve Data

The resource availabilities and unit cost projections have been combined to form electricity cost supply curves. These are presented in tabular and graphical form below.

Underlying these curves is the assumption that levelised unit costs will mark entry points into the wholesale market. As electricity demand in concert with the generation available to the grid lead to wholesale electricity prices projected to be similar or higher than the assessed unit costs, then the next least expensive generation option will be taken up to supply the demand.

Table 6: 2012 Cost Supply Curves by Technology 10% WACC Medium Confidence Level (GWh/annum)

c/kWh	Hydro	Geothermal	Wind	Biomass[1]	Solar
2-4	-	200	-	-	-
4-6	3,200	-	1,165	100	-
6-8	2,785	3,620	3,965	-	-
8-10	2,995	630	2,200	285	-
10-12	755	-	1,170	425	-
12-14	640	-	765	705	100
14-15	990	-	285	-	160

1. Woody biomass, landfill gas and other biomass options have been aggregated for this table.

Figure 2: 2012 Cost Supply Curves by Technology

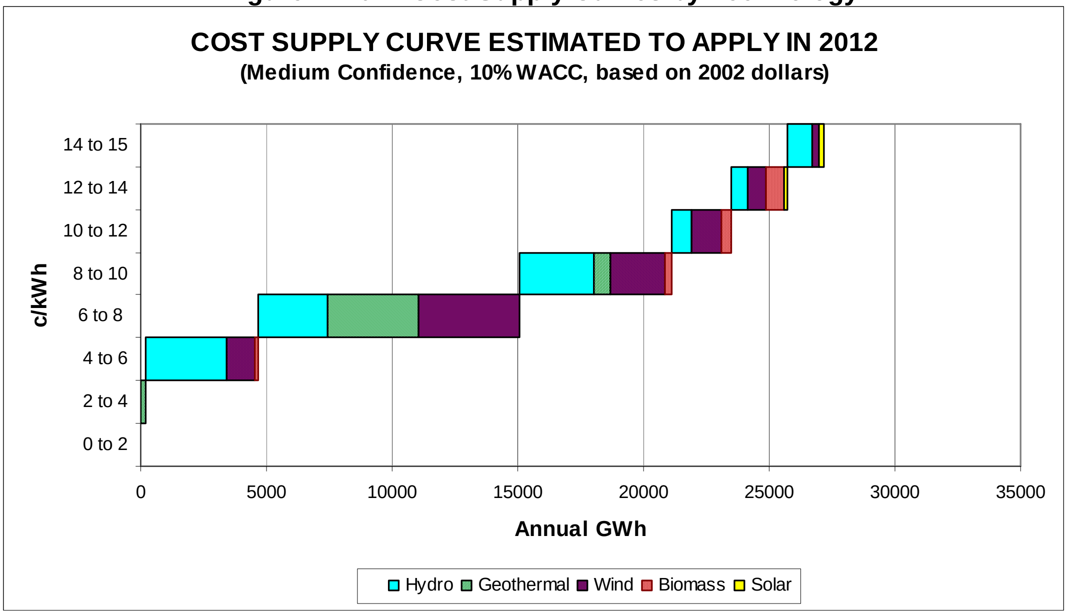
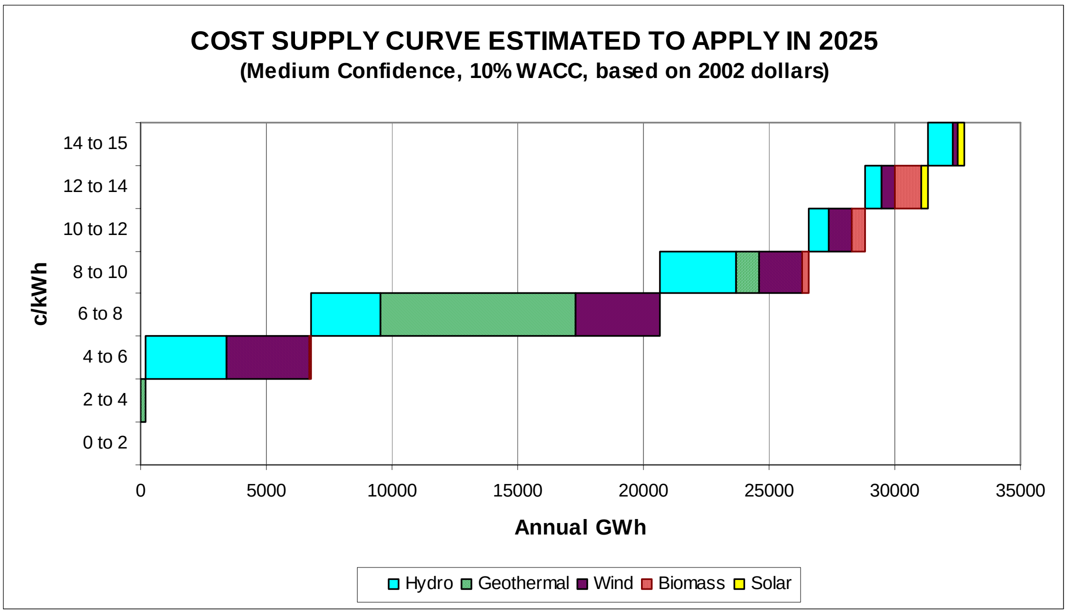


Table 7: 2025 Cost Supply Curves by Technology 10% WACC Medium Confidence Level (GWh/annum)

c/kWh	Hydro	Geothermal	Wind	Biomass[1]	Solar
2-4	0	200	-	-	-
4-6	3,200	-	3,280	100	-
6-8	2,785	7,750	3,355	-	-
8-10	2,995	930	1,705	285	-
10-12	755	-	925	565	-
12-14	640	-	550	1,060	200
14-15	990	-	190	-	290

1. Woody biomass, landfill gas and other biomass options have been aggregated for this table.

Figure 3: 2025 Cost Supply Curves



A comparison of Figures 2 and 3 shows that:

- Hydro resources are fixed in quantity and in price. The lowest cost hydro block (at 4-6c/kWh) is all associated with Meridian Energy's Project Aqua.
- Geothermal resources are significant in the 6-8c/kWh band. These include a number of high temperature field developments. The quantity available is greater in 2025 because this gives more time for staged development.
- A low cost (2-4c/kWh) geothermal option exists based around increased utilisation of the Poihipi Rd station using steam from the Wairakei field (requires additional resource consents).
- Some wind resource becomes available in the 4-6/kWh cost band in 2012. However, the technology is maturing resulting in progressive lowering of costs, such that more of the resource could be in the 4-6c/kWh cost band by 2025. In practice, much of the prime resource in this cost band may have already been developed before 2025. The total available wind resource by 2025 is slightly greater due to more resource being brought in under the 15c/kWh cut-off point.
- Biomass can make a small contribution in the 4-6c/kWh range (associated with landfill gas projects). In 2012 the woody biomass resource is not available until the 8-10c/kWh cost band. Its uptake could be helped by its ability to embed in the local network, and perhaps to assist network alleviation for the new mills that must be developed to process the large quantities of new timber becoming available in the coming period. The added volume of timber processing increases the quantity of process residue available with time. In addition, the price of woody biomass developments drops with time due to maturing technology.
- Solar hot water heating is seen to make a small, but significant contribution above 12c/kWh. Given that this technology competes at the retail end of the market, and that it is currently competitive, then the opportunity for increased uptake could be significantly greater if electricity market prices increase.
- The above discussion is based on assessed resources at 10% WACC and medium confidence levels. Data in Appendix A should be referenced to see the effect of selecting the high confidence level or alternative WACC values.

3.5 Comparison of Electricity Supply Curve Data with that of the 1993 Ministry of Commerce Report

The analysis above is more than a reindexing of the previous Ministry of Commerce report “Renewable Energy Opportunities for New Zealand”. The 1993 report looked forward 20 years to 2013. Some resource has been taken up e.g. the Manapouri second tailrace tunnel. The following table makes a brief comparison between the two assessments at a medium confidence level using the 2012 data.

Table 8: Comparison Between the 1993 Report and the Current Report

Resource	Unit Cost (c/kWh)	Energy Quantity (GWh/y)	Current Report[1]
Geothermal Geothermal (Binary)	5-6 4	9,750 12,000	Geothermal energy is still seen as providing low cost solutions. Exchange rate movements account for an increase in unit cost to around 7c/kWh for 3,500GWh of high temperature resource. The quantity varies because of a more comprehensive assessment of resources and recognition of staging restrictions. 700GWh/y of production has been developed in the interim. The earlier report assumed that binary plant could be added to all fields to match current or planned production. Binary plant potential is now recognised as limited with approximately 630GWh/y at 8-10c/kWh.
Hydro	7-10 10-15	13,850 15,100	Hydro projects generally cover the same price bracket with the exception of the innovative Project Aqua (4-6c/kWh for 3,200GWh/y). A more conservative view has been taken on consents, such that total available resource is assessed at 11,370GWh/y.
Wind	8-10 12-14 14-16	2,170 6,355 1,470	Detailed resource assessments have now been undertaken showing an available resource of 9,550 GWh/y with 150GWh/y having been installed recently. The technology has been maturing such that unit cost has dropped (and will continue to drop). Generation in the 4-6c/kWh range will be possible, with the largest resource in the 6-10c/kWh range.
Biomass: Residues Plantations Arisings Firewood	 5-9 9-14 9-14 11-22	 280 2,060 970 1,480	Biomass is still seen as a valuable contributor. The capital cost of combustion plant had been severely underestimated in the 1993 report (approximately half of the current estimate) and this had distorted all analysis. Residues have not been assessed for this report. Plantation fuel cost is such that unit cost is outside the 15c/kWh cutoff for assessment. Firewood contribution is assumed to be unchanged from current usage. Process residues and forest arisings can be developed in the 10-14c/kWh range (1,415GWh/y). A maturing gasification technology could assist uptake. This report includes landfill gas in the high and medium confidence assessments, with 100GWh/y in the 4-6c/kWh unit cost band (>20GWh/y has been installed since the 1993 report)
Solar Hot Water	-	-	The 1993 report included 880GWh/y in their low confidence category in a 14-18c/kWh price band. This report includes 260GWh/y in the 12-15c/kWh range at medium confidence.

1 Energy quantities are on a consumer energy basis.

4. HEAT SUPPLY

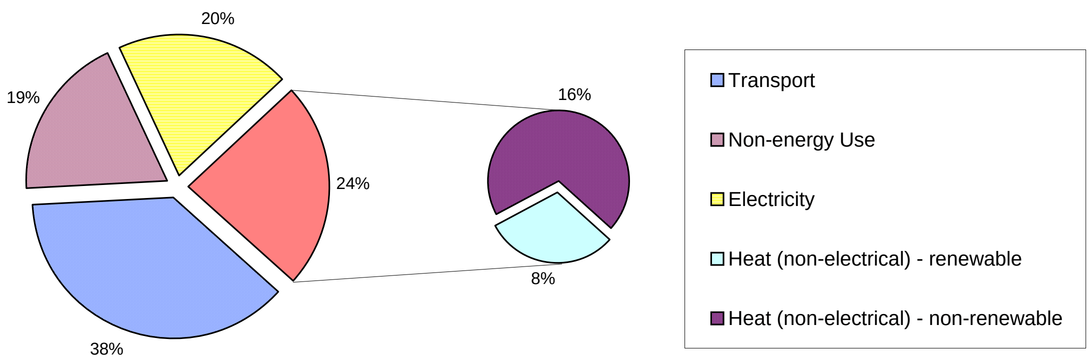
4.1 National Heat Consumption

As mentioned earlier, heat is a major component of the national energy mix. It has been necessary to treat it differently to electricity in terms of the development of cost supply curves. While costs for heat plant can be assessed, these costs are a function of size. A rough assessment can be made of future heat plant size say in the forestry industry. However, heat plant size across the breadth of New Zealand industry is to a large extent unknown. Consequently, cost supply curves cannot be derived (although a partial curve looking at the forestry industry with supply from woody biomass is provided in the chapter on woody biomass (Appendix A and Appendix B, Chapter 4)).

Instead the following discussion emphasises that there are some attractive renewable options for heat. In Appendix E, the value of heat from fossil fuel sources is derived. This is used as the basis for comparison with renewable energy options.

Figure 4 shows the component of heat within the national energy resource use of 600PJ of consumer energy (based on the Energy Data File July 2001). Approximately 24% of the energy use is for heating, while a significant portion of electrical use is directed to heating also (about 30% of this electrical use is directed to domestic space/hot water heating). In total, heating demand is greater than electrical (non-heating) demand, so the ability to displace either electrical or non-renewable-sourced heating with heating from a renewable source will have significant national benefit.

Figure 4: Components of Final Consumer Energy Use (Year 2000)



Nationally, understanding of heating requirements and characteristics is limited. At a domestic level, BRANZ has been undertaking considerable research on home energy usage. Commercial and industrial data have not been co-ordinated (though data may be held in confidential databases). For these larger users, heat is sourced from a range of boiler sizes or from cogeneration/combined heat and power.

Without detailed knowledge on boiler sizes and their load factors across all industries, it is not possible to develop the costs and ratios between the potential sizes for a reasonable cost supply curve for heat applications. Each application will be site specific. However, potential benefits from uptake can be indicated by approximate aggregated cost curves.

4.2 Opportunity for Renewable Displacement of Fossil Fuels for Heat

Table 1 listed renewable resources that could supply process heat needs. The major potential suppliers are geothermal and woody biomass. These are compared again in Table 9. For comparison, the total consumer energy for heating purposes was approximately 150PJ in the year 2000.

Table 9: Available Resources in Terms of Primary Energy for Process Heat Supplies (PJ/year)[1]

Resource	2012			2025		
	High	Medium	Low	High	Medium	Low
Geothermal[2]	83	160	710	196	319	710
Woody Biomass[3,4]	6	21	73	12	28	91

1. Unlike the electricity assessment, it is not possible to state these resources are all under $25/GJ in terms of delivered heat. Unit costs are a function of load size (see figure 5) and load size is unknown.
2. The geothermal assessment excludes all low temperature resources due to incomplete data.
3. In this case, the woody biomass resource is the whole resource and not just that associated with a forestry industry process heat need.
4. Landfill gas and other biomass energy options have not been considered for heat because of the past difficulty in attracting industry to a waste environment.

Supply of heat to a locality is more difficult than supply of electricity. As a rule, loads must be attracted to the energy source. Geothermal energy is available in the Central North Island and Northland, with minor heating potential elsewhere. The scale of geothermal energy available for direct heat is vast compared to most existing heat requirements. Heat loads must be within a limited radius of the resource and preferentially be located immediately adjacent. In the list of renewable energy sources given in Table 1, only woody biomass stands out as a widespread resource that could be transported to the load source. There may be opportunity to convert other biomass sources via biogas to a liquid fuel for transportation to a range of uses, but these resources are limited.

Note that the potential of this widespread wood fuel has now been recognised and new businesses are evolving as suppliers of a controlled woody biomass fuel in a commercial manner.

For the analysis in this report, most woody biomass resources have been directed to electricity generating stations (to enable a comparison with other renewable resources in terms of the electricity cost supply curves). In the short term, the unit cost of biomass electricity is not attractive, except in niche opportunities, and the real opportunity for use of woody biomass is as a fuel for process heat supply.

It should also be noted that not all heat is equal in the industrial market, with some processes being more sensitive to variations in supply quality and reliability than others. One big difference between geothermal, biomass and gas is that it is easier to build control systems (and the software interface) for a gas-fired system.

Heat costs for fossil fuelled heat plant have been derived in Appendix E. This currently has an upper bound of around $14/GJ for plant fired by gas at remote ends of the gas transmission system. This data is shown in Figure 5.

There is a significant difference between South Island and North Island coal-fired heat. This could make displacement of South Island coal by renewables more difficult, especially given that woody biomass is the only alternative.

Significantly, a large premium (possibly 50% more) can be paid for gas-fired heat versus coal-fired heat. Reasons for this may include:

- Lower initial capital investment for gas
- Higher WACC/lower payback period actually required by businesses
- Convenience of gas with respect to supply and handling
- Less land is required for stores, fuel handling and for heat plant itself
- Clean nature of gas supply
- Perceived environmental benefits of gas over coal in terms of triple bottom line reporting (especially on the international scene).

Note that a unit cost for heat plant of $25/GJ equates to a unit cost of 9c/kWh.

Figure 5: Heating Options from Renewable Resources (85% Load Factor, 10% WACC), 2012/2025)

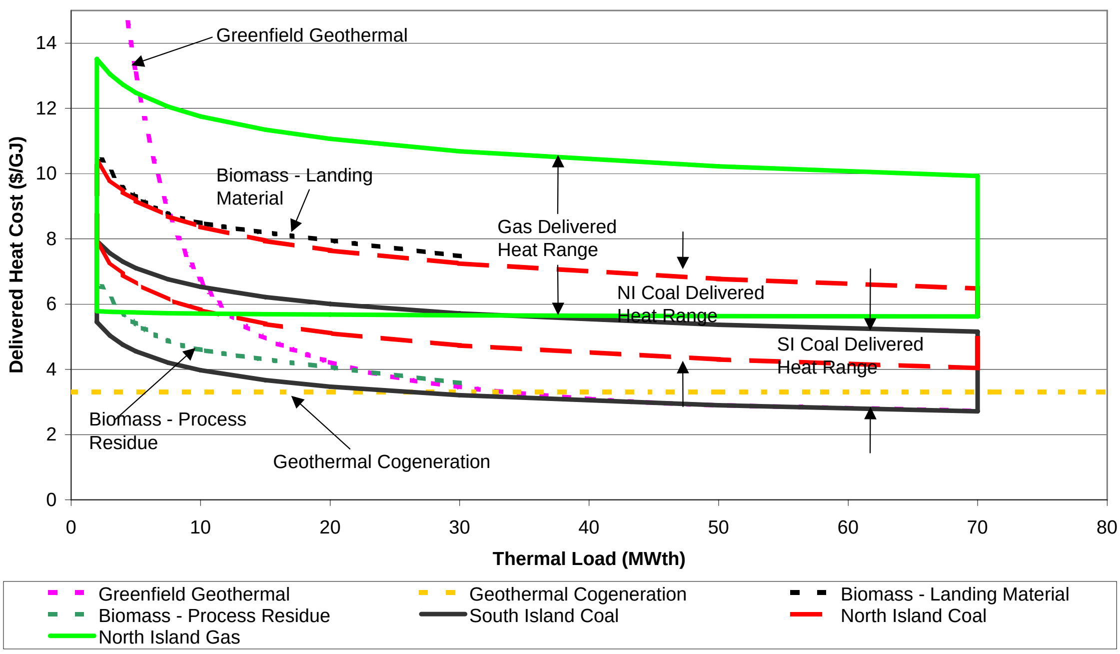


Figure 5 compares the delivered cost of energy (from the heat plant) for woody biomass and geothermal energy with the range of costs for heat from fossil fuelled plants.

From this figure the following conclusions can be drawn:

- Woody biomass is a more direct competitor to coal rather than gas. Heat from process residues should be competitive with North Island coal, and in parts of the South Island.
- Where suitably located, geothermal energy may be able to displace some coal and a baseload portion of gas if delivered in a hassle-free manner to the consumer.
- A full greenfield geothermal development dedicated to heat supply could be justified if of large scale with high load factor (and would be further helped by availability of existing wells).
- A process industry attracted to co-site by a geothermal power station could secure a very attractive heat price.
- Biomass heat plant reliant solely on forest material (if not supplemented by process residue) will be marginal or not competitive.

- Any increase in the effective gas or coal price (whether due to the need for alternative sources or due to special charges) will raise the target price range for heat and could begin to draw in a wider range of renewable heat alternatives.

5 CONCLUSIONS AND RECOMMENDATIONS

A substantial renewable resource is available for electricity generation or heat supply.

Best estimates have been given for real opportunities, helped by the fact that to a large extent the technologies and resources for development are well established/well researched.

Assumptions have been made regarding resource availability and consentability, of plant “buildability” and of the limiting uptake rate for the various technologies. Cost projections have been checked across a range of research and physical projects. These assumptions have been based on the experience of the reviewers with relevant sections of the report being cross-checked by expert groups (New Zealand Geothermal Association, Bioenergy Association of New Zealand, Solar Industries Association) or by authors of recent industry reports (covering hydro, wind, solar hot water and photovoltaics) though opinions may differ.

Assessed available resources are considerably increased in a more liberal consenting environment (associated with a shift from “high” to “medium” confidence assessments).

The unit cost of renewable technologies is more strongly influenced by capital cost than the unit cost of fossil fuel plant, for which fuel has the major influence. As all major plant is imported, reduced value of the New Zealand dollar will penalise renewable plant (with lesser effect on hydro) over fossil fuel plant.

Utilisation of these resources could help New Zealand towards Kyoto Protocol goals, provided adequate investment incentives are available at a commercial level.

While global environmental concerns are helping to focus attention on renewable energy sources as a potential solution, these same resources face strong environmental constraints/opposition at the regional level. In some cases, National Policy Statements could be required to give Regional Councils a new framework for decisions. Developers observe that it is far easier to obtain resource consents (and there is less public opposition) for Combined Cycle Gas Turbines than for hydro or geothermal developments.

Given uncertainties in the heat market size, there could be benefit in undertaking research into both heat and electricity demand on both a regional and sectorial basis.

There is clear evidence that renewable resources can provide heat at competitive prices.

Investment in renewables can be supported by the Government’s policies (including through the implementation of the National Energy Efficiency and Conservation Strategy), and its continued strategic investment in research (through FRST), as well as through its information dissemination activities (by the Ministry of Economic Development, the Ministry for the Environment, the Energy Efficiency and Conservation Authority, etc).

APPENDIX A: RENEWABLE ENERGY SOURCES/TECHNOLOGY SUMMARY DATA SHEETS

HYDROPOWER

ENERGY RESOURCE	Potential gravitational energy in water raised during the hydrological cycle.
Supply is dependent on topography (storage and head) and meteorological conditions (rainfall and river flow). Energy resource is specific to each site location and the merit of developing the site will depend on the head and flow conditions, engineering issues, consentability, cost of generation, and the distance to load centres.	

SYSTEM ELEMENTS	Diversion and storage, generation, and transmission.
Rivers may be impounded or diverted. Diversion may be to increase flows or to maintain head. Diversion structures, canals and tunnels used. Natural lakes can be used for storage, structures can be used to increase/manage their levels. Artificial impoundments and/or head is created by damming rivers. Spillway features to cope with flood flows, and release structures to maintain minimum flows are incorporated. Power generated by passing water under head through a turbine generator set. Water returned to rivers, lakes. In-situ river turbines possible but very rarely used. Power transmitted to national/local distribution lines.	

SYSTEMS AND APPLICATIONS	Grid/embedded power. Run of river, storage or pumped storage. Cascade catchment development.
Embedded power: Output can be dedicated to a specific user (e.g. pulp mill), or fed directly to a network company but generation fed directly to the national grid predominates. *National grid power:* Large bulk generation. Economies of scale. *Run of river:* Such schemes have very limited storage capacity. Their output depends on river flows, and will vary accordingly. New Zealand system has very limited storage, almost run of the river. *Storage systems:* Have enough reservoir/lake storage to impound high flows for use during low flow periods. A smooth power output in excess of low flow limits can be achieved. *Pump storage:* Energy generated from other sources (e.g. wind or thermal) used to pump water from turbine tailraces to headwater storage. This water can be used for peak demands or to smooth out variations in other power supplies. Not currently economic and therefore excluded from this report. *Stepped Canals:* Water can be progressively used in a series of power stations in a cascade manner down a catchment. Full catchment development can provide water management and energy output benefits.	

TECHNICAL STATUS	Commercial, proven, mature technology, yet still improving.
Continuing improvements in techniques for site selection, conceptual design, plant design, and construction; innovative civil works, particularly for remote sites; generating plant and controls, standardisation. Improvements in turbines and draft tubes have revitalised old marginal stations and improved power output from others. 0ptimised for cost of generation, not maximised use of resource.	

APPLICATION LIMITS AND SYNERGIES	Consentability, inflow variations, residual flow. Flood control/irrigation.
Principal constraints determined by consentability, community interests, required residual flows and impact on local communities. Hydro investment can be combined with irrigation projects and other water supplies, flood protection schemes, water navigation, and river bridging needs, etc.	

CRITICAL FACTORS	Resource location, engineering and environmental issues.
Remote locations increase construction costs including transmission line costs and transmission losses. Location plus consent conditions, head, flow, geological conditions, etc. affect the cost per installed capacity. Flow available, potential storage and turbine size affect capacity factor, or degree of utilisation, the other key economic element. Hydropower development affects catchment hydrology and habitats. Loss of special or representative habitats and amenities can raise public policy concern over the details of particular projects. High potential mitigation benefits available through good design and public consultation, particularly with resource experts e.g. DoC, Regional Council.	

ENVIRONMENTAL ISSUES	Ecosystem and amenity changes. Construction impacts with large-scale development.

Hydro development alters river and lake habitats and water regimes. Sediment balances can be altered, and ecological effects may extend to coastal environments. Increased water residence time from impoundment can create water quality problems. Recreational and scenic amenities can be replaced with others of a different nature. Ownership of rivers is a Treaty of Waitangi issue.
Construction of major projects can have a significant social impact on nearby communities extending over many years. The impact can be managed and townships can be left with improved community facilities. Achievement of potential development often depends on good public consultation and involvement in identification of mitigation opportunities.
Hydropower is generally a safe power source with only a few significant failures internationally. Land stability and induced seismicity may be issues.

Region	**Potential for Development MW**			**No. of Potential Schemes**	**Potential Energy Output GWh/y**
	High Confidence	**Medium Confidence**	**Low Confidence**		
Northland	-	-	-	-	-
Auckland	-	-	-	-	-
Waikato	8	24	44	8	252
Bay of Plenty	25	108	258	13	1,196
Gisborne	12	37	37	3	163
Hawkes Bay	51	154	154	7	779
Taranaki	0	22	48	4	230
Manawatu-Wanganui	53	144	144	8	704
Wellington	0	6	6	1	25
Nelson-Marlborough	35	48	83	6	408
West Coast	0	373	758	24	3,414
Canterbury	919	919	1,047	14	5,755
Otago	0	364	869	13	4,335
Southland	0	0	85	2	370
Total New Zealand	1,103	2,199	3,533	**103**	**17,630**

ENERGY SUPPLY COSTS	

Capital costs for hydro development vary quite significantly. O&M costs are relatively minor. Technological innovation is not expected to cause costs to fall over the timeframe of this report. Some site specific cost reductions may occur where a particular innovation becomes feasible.

Supply Cost Data	**c/kWh**	**MW**	
		WACC = 5%	**WACC = 10%**
High Confidence	2-4	700	-
	4-6	300	570
	6-8	105	130
	8-10	3	200
	10-12	-	100
	12-14	-	40
	14-15	-	65
Medium Confidence	2-4	1,070	-
	4-6	825	570
	6-8	340	500
	8-10	15	670
	10-12	30	155
	12-14	15	140
	14-15	5	205
Low Confidence	2-4	1,590	-
	4-6	1,080	575
	6-8	945	1,015
	8-10	175	875
	10-12	315	200
	12-14	50	370
	14-15	85	575

Supply Cost Data	**c/kWh**	**GWh/y**	
		WACC = 5%	**WACC = 10%**
High Confidence	2-4	3,830	-
	4-6	1,595	3,200
	6-8	510	630
	8-10	10	1,095
	10-12	-	500
	12-14	-	185
	14-15	-	325
Medium Confidence	2-4	5,985	-
	4-6	3,750	3,200
	6-8	1,635	2,785
	8-10	70	2,995
	10-12	145	755
	12-14	70	640
	14-15	30	990
Low Confidence	2-4	8,515	-
	4-6	5,005	3,265
	6-8	4,465	5,250
	8-10	845	3,905
	10-12	1,470	1,100
	12-14	240	1,750
	14-15	390	2,715

FURTHER RESEARCH AND OTHER ISSUES	Significant refinement of supply data possible, but at considerable costs.

Cost-energy quantities are derived from engineering judgement and previously published reports. Considerable study effort would be needed to further differentiate cost of supply and energy output estimates. Individual schemes would need closer examination which raises the issue of proprietary nature of information.

GEOTHERMAL

ENERGY RESOURCE	Earth heat accessed through a water media, frequently in a staged manner.
High Temperature Resources: Typically are associated with fluids in excess of 170^{o}C and up to 340^{o}C, associated with "recent" volcanism. Can be used for electricity generation or heat. *Low Temperature Resources:* Less than 170^{o}C frequently associated with deeply circulating groundwater. Use is limited to heating buildings and low-grade process heating, e.g. drying, fish farming. *Ground Source Heat Pump Resources:* Uses thermal inertia of ground or groundwater as an alternative to air temperature for heat pump duty. (Excluded from this review.)	

SYSTEM ELEMENTS	Natural surface sources, or drilled wells. Fluid separation and treatment, heat exchange and use, disposal.
Extraction: Water could be channelled from a natural spring or from a drilled well, resulting flow controlled and piped. *Treatment:* Steam and water separated and other impurities possibly removed. *Heat exchange/use:* Steam can drive a turbine or supply process heat, hot water can be put through a heat exchanger for space or water heating, or to energise binary cycle power plant (uses low boiling point fluid), or used directly (e.g. bathing). Ground source heat pumps require lengths of buried pipes to exchange heat with the ground/ground water. *Disposal:* Waste or spent fluids reinjected via wells into the field or (rarely) discharged to land or waterways. These fluids may need treatment (e.g. anti-scalant) prior to discharge. Gas normally dispersed via cooling tower.	

SYSTEMS AND APPLICATIONS	Application field temperature dependent, cascade use efficient, high temperature process steam financially attractive, development scale is variable, continuous operation is preferable.
Indicative field temperature (^{o}C) use relationship: 30-69 thermoculture, bathing; 70-140 space and water heating, drying; 140-220 drying, process heat, binary electrical plant; 220+ steam turbine electricity or process steam. *Cascade*: Fluids used for one high heat purpose may still have enough energy for lower grade purposes. With a high temperature field, steam can go to a turbine and the separated hot water to binary plant for electricity production then direct heat for other uses within the limitations imposed by silica content. *Parallel*: As an alternative to cascade applications, process heat can be supplied prior to, or in parallel with the electrical plant. *Size*: Advantages in large-scale development, but small-scale plant often viable due to existing wells. Staged development of a field is useful for initial field proving – reduces risks but can negatively impact on economics.	

TECHNICAL STATUS	Plant technology proven. Field assessment uncertainties (but less so than overseas owing to a legacy of past Crown investigations and public domain information).

Some community uses are ancient. Kawerau and Wairakei plants >40 years old demonstrating reliability of energy extraction, use of technologies and importance of sustainability of rate of extraction. New Zealand technical expertise recognised internationally and being a positive contributor to New Zealand revenues. Whereas New Zealand was a world-leader in this technology and associated research, it has been moving towards a follower status, there being insufficient domestic industry base to support much leading edge research.

Major matters warranting attention:

- Application of advanced geophysical techniques to better identify field boundaries and most productive zones e.g. active seismic and passive microseismic techniques (subject to cost considerations).
- More refined reservoir resource assessment and modelling during operation (this requires greater attention to input data).
- Economic extraction of some dissolved minerals.
- Inhibiting silica or calcite deposition.
- Optimised steamfield and station design.
- Application of better drilling techniques to deal with lost circulation and to maximise well production.
- Understanding and mitigating environmental effects.
- Reduction of perception of environmental impacts.
- Reduction of perceived financial risk.

Note: Technologies for directly tapping magma are at the conceptual stage. Hot dry rock extraction using very hot deep rock (by making hydraulic fractures and passing water between wells) at R&D stage. Both are unlikely to have commercial application in New Zealand within the next 25 years and are not covered by this review.

APPLICATION LIMITS AND SYNERGIES	Sustainability, cost and locality constraints.

Resources are treated as being of finite size (though do recharge) and development is limited to ensure sustainability and minimise externality effects. Occasionally fluid disposal issues may limit use for small-scale industrial, commercial and domestic uses.

There is a lack of a clear definition of sustainability in the Resource Management Act context. Inconsistencies in previous decisions are hampering development. Sustainability tends to be confused with renewability.

Electricity can be directed to the grid or used at factory level. Direct use for heating is possible down to domestic level provided users are within an acceptable radius of the resource (<20 km). Major process loads may justify transmission over distances of up to 20 km. Continuous extraction of fluid is preferable compared with intermittent or variable use for the higher temperature applications from capital recovery (but not a technical) perspective.

Synergies are possible with other renewable sources to optimise and smooth energy supply. Low heat, distributed use or process heat utilisation opportunities are limited because of economies of scale and practice. Special synergies are possible with landfills to optimise methane production and with forestry industry in supply of process heat. There is the possibility of assisting the production of alcohol from whey at the Reporoa dairy factory.

CRITICAL FACTORS	Locality of energy demand, resource sustainability, drilling costs and field life.

Locality of demand.

Electricity transmission constraints near Whakamaru need to be removed to allow export of power northwards.

Consenting process is highly restrictive, and can add considerable time and cost. A National Policy Statement may be required to facilitate development and to put greenhouse gas issues into the framework for Council decisions.

Staged exploration and development minimises risk for the initial stages, but should be followed by large–scale development to maximise benefits.

High cost of proving the resource (but this has been done by the Crown in many cases). Better science will reduce the need for/improve the siting of exploration/development wells.

Capital intensity of geothermal investment is offset to a degree by developing fields in a sustainable way which gives them a long life expectancy.

ENVIRONMENTAL ISSUES	Change of natural thermal features. Renewability concern. Public concern about subsidence and hydrothermal eruption. Some greenhouse gas emission.

Consenting process is normally precautionary and staged. Issues revolve around sustainability and community concerns (whether founded or not) about subsidence and hydrothermal eruption risk, and impacts on tourism. Consenting process is restrictive such that a 100MW station will probably require appeal to the Environment Court with associated cost and delay. (It is easier to consent a CCGT plant and there are fewer objections).
Environment Waikato has a “single tapper” policy to avoid in-field conflict over resource use.
Protection has been given to certain resources or moratorium applied where resources appeared to be stretched. Priority has been given to protection of chloride water features.
A “Protected 2” category has been suggested in the latest Proposed Waikato Regional Plan which would effectively remove a number of good development fields from further consideration. This has been appealed against by Contact Energy. The Regional Councils take a protective attitude. There is a need for a National Policy Statement covering geothermal and other renewables.
Resources are altered by exploitation but sustainable developments can be selected. There is debate over the “renewability” of the resource.
The resource is seen as a taonga by Maori. Maori are not necessarily anti-development, with Maori Trusts playing a key or lead role in recent developments.
Fluids are normally reinjected, minimising effects on surface waters and flora/fauna (although Wairakei is a notable exception partly for historic reasons).
Gases are emitted with the fluids. CO_2 emissions average around 100 g/kWh compared with CCGT plant emissions of 430 g/kWh or best practice coal stations of 955 g/kWh.

NEW ZEALAND RESOURCE	Substantial development potential.

Surveys indicate New Zealand has 129 geothermal areas, 41 with temperatures below 30°C, or unmeasured but only warm, and 83 areas above 30°C. The latter are broken into categories according to temperature: 30-69°C - 52 areas, 70-140°C - 14 areas, 140-220°C - 7 areas, and >220°C - 15 areas.
All of the high temperature fields (which offer the most energy potential) are found in the Rotorua/Taupo region with the exception of Ngawha in Northland. Almost all the present use of geothermal resources occurs in these regions.
There is insufficient data to estimate the energy potential-supply costs of the fields with temperatures below 220°C. The potential for the high temperature fields for electricity production is shown below. Availability for energy/non electricity uses is large.
Resource behaviour does change with time requiring active engineering/management to maintain output.
Currently there is approximately 440MWe of installed geothermal generators producing about 2,270 GWh/yr. In addition, there is in excess of 7,000TJ/yr of direct heat use.

ESTIMATED ADDITIONAL ENERGY AVAILABLE FROM HIGH TEMPERATURE GEOTHERMAL FIELDS

Area	**Year 2012**				**Year 2025**				**Years 2012/2025**	
	High Confidence		**Medium Confidence**		**High Confidence**		**Medium Confidence**		**Low Confidence**	
	MWe	**GWh/y**	**MWe**	**GWh/y**	**MWe**	**GWh/y**	**MWe**	**GWh/y**	**MWe**	**GWh/y**
Taupo Volcanic Zone	270	2,150	520	4,130	670	5,280	1,065	8,380	2,400	18,890
Northland	20	160	40	320	20	160	65	500	110	860
Total	**290**	**2,310**	**560**	**4,450**	**690**	**5,440**	**1,130**	**8,880**	**2,510**	**19,750**

Table shows cumulative confidence level e.g. low confidence resources are the sum of high+medium+low confidence resources

ENERGY SUPPLY COSTS	Moderate capital, and O&M costs offset by high capacity factor.

Geothermal development generally has lesser capital requirements than hydropower - $2,500/kW-$4,000/kW. There are economies of scale, but these are diminished by modular nature of developments and the existence of Crown wells. Further economies are possible with the use of second hand/refurbished equipment. In the long term, price is expected to stay around this level due to counteracting influences of plant improvement but increased cost of wells. Significant O&M costs are involved due to well replacement to maintain production, and ancillary plant such as waste treatment. These costs are offset by a high capacity factor >90% giving relatively cheap electricity.

Where a geothermal power station is operated as a Combined Heat and Power facility, steam can be profitably sold at prices in excess of $3.30/GJ (compared with a target price of $5/GJ to $8/GJ). For a greenfield process heat development, high load factors and large thermal loads are required to ensure profitable steam supply. This can be over-ruled by presence of existing wells or for highly productive fields.

ESTIMATED SUPPLY COST DATA FOR GEOTHERMAL ELECTRICITY GENERATION

Supply Cost Data	**c/kWh**	**Year 2012**		**Year 2025**	
		GWh/y		**GWh/y**	
		WACC = 5%	**WACC = 10%**	**WACC = 5%**	**WACC = 10%**
High Confidence	2-4	200	200	200	200
	4-6	2,030	-	5,160	-
	6-8	80	1,790	80	4,780
	8-10	-	320	-	460
	10-12	-	-	-	-
Medium Confidence	2-4	200	200	200	200
	4-6	4,100	-	8,530	-
	6-8	150	3,620	150	7,750
	8-10	-	630	-	930
	10-12	-	-	-	-
Low Confidence	2-4	200	200	200	200
	4-6	17,670	-	17,670	-
	6-8	1,880	16,450	1,880	16,450
	8-10	-	3,100	-	3,100
	10-12	-	-	-	-

Cost supply curves have not been estimated for direct heat or non-power uses of geothermal energy.

The cost supply data are indicative of four types of development: a) Poihipi Rd reconsenting, b) new high temperature developments, c) Wairakei binary cycle (using waste heat), d) other binary cycle projects.

FURTHER RESEARCH AND OTHER ISSUES	Records of geothermal use inadequate. Low-grade heat use unknowns.

No comprehensive record of the use of geothermal energy throughout New Zealand, especially at low and moderate temperature end. Similarly, there is no national assessment of low-medium temperature resources.

The availability and cost of low-grade heat is very dependent on wider utilisation of geothermal fluids. It is very locality specific and dependent on whether the low-grade heat is a by-product or primary source of energy.

Research can be directed at:

- Geophysical techniques to identify reservoir boundaries
- Refined reservoir testing and modelling
- Treatment/extraction of dissolved chemicals
- Drilling technique improvement
- Alternative funding arrangements
- Effects of aggressive geothermal environments
- Long distance transmission of geothermal energy
- District heating
- Ground-source heat pump applications (including water heating)
- Minimising and mitigating environmental impacts

WIND POWER

ENERGY RESOURCE	Wind caused by atmospheric temperature/pressure gradients utilised to provide mechanical and electrical power.
Energy potential of wind varies approximately according to the third power of the wind speed. Small increments in wind speed can therefore significantly alter the resource potential. Energy production also depends on the shape (flatter the better) of the annual wind speed distribution.	

SYSTEM ELEMENTS	Wind turbine, drive train and generator, support structure. Predominant form: horizontal axis three blade turbine.
Wind turbine: Two approaches - vertical axis machine (the blades move around a vertical line perpendicular to the wind direction) and more familiar horizontal axis turbine with two or three blades. Horizontal axis three blade configurations predominates. *Support structure:* Tower supports the drive train, generator and mechanical controls. Typical grid connected machine (850 kW) stands around 60-65 metres tall with three 25 metre long blades. *Drive train, generator:* Turbine power is usually converted to electrical energy. Grid connected induction generators dominate. Between rated and maximum (cut out) wind speed a fairly constant power output is obtainable.	

SYSTEMS AND APPLICATIONS	Wind farms - Grid power; hybrid systems; direct mechanical uses.
Turbines of 660 kW-850 kW-1.5 MW supplying grid power are the common application. Usually arrayed into wind farms - multiple wind turbine units forming a single managed unit in contiguous area. Modular nature of units means variable wind farm capacity, generally a wind farm of several MW. Wind power can be combined with diesel generators in remote locations to provide economic hybrid systems. Wind also used to directly power water pumps.	

TECHNICAL STATUS	Technology mature. O&M cost and lifetime reasonably well understood.
Wind power R&D started with both very large and small machines. Design converged to intermediate sizes. Height and power output now increasing to take advantage of better wind conditions at elevation, and economies of scale. Trend helped by better understanding of fatigue and other material stress issues. Experience with wind power at grid scales is limited to 15-20 years - now a lower level of uncertainty over O&M costs. These costs tend to increase through machine lifetime. Lifetime reasonably clear - may be 20 to 25 years with a major overhaul after 10 years.	

APPLICATION LIMITS AND SYNERGIES	Backup power supply. Integration with National Grid. Close to load centres.
Wind power cannot be relied upon solely unless there is an energy storage system or supply can be firmed by other energy sources that can cover any wind shortfall. Wind power penetration may be limited to 20-30% but power control equipment can assist penetration. Cost of significant spinning reserve (thermal turbines ready to instantly provide power) may reduce wind power benefits. Wind sites often remote with need for transmission lines to obtain link to grid. Wind strengths at New Zealand sites fluctuate, but year by year variation in total energy potential is small – about ±10 %.	

CRITICAL FACTORS	Siting issues. Cost of transmission. Community perceptions.
Energy outputs sensitive to average wind speeds. A 10% reduction in wind speed can mean a drop of up to 30% in output. Site selection based on careful measurement is crucial. New Zealand has many good sites but some sites near load centres are also near large communities who may be concerned about visual aspects. Electricity costs in New Zealand means only very good sites will be attractive initially. Sites developed to date are in the 10 m/s category c.f. lower wind speeds overseas generally (6.5-8.5m/s).	

ENVIRONMENTAL ISSUES	Visual impact. Land use issues. Noise and telecommunications interference.

The visual impact of wind farms in the landscape can be partially dealt with by careful siting and design features. Opponents of wind sites often opposed on visual grounds regardless of design.
Wind power plant only occupies 1% of a wind farm site. The balance can be retained in previous land use
Impact of wind power on bird life appears slight.
Standard for wind turbine noise is A/NZS 6808.1998. Usually rural noise limits are set at the notional boundary of a dwelling. Suitable land use buffer zone needed.
Telecommunication interference tends to be localised and can be mitigated in most cases by siting design, various instrument/appliance retrofit means.

NEW ZEALAND RESOURCE	Data for wind farms, not stand alone/hybrids. Very large resource. Optimistic estimate: over 13,000 GWh.

Current wind power use is not significant providing about 150 GWh p.a. of electricity or less than 0.5% of New Zealand's electricity energy.
New Zealand is generally windy with a large wind power resource. The resource that could be developed might be 50 TWh pa or even more. While there is insufficient data to confirm this figure and break it into cost classes, this review goes some way towards that at the higher wind speeds.
There is also insufficient data to provide national resource quantity estimates for stand alone units. These tend to provide expensive power but may be used at remote sites where cost is justified. Total resource uptake not likely to be noteworthy (a thousand 40 kW units = 100 GWh).
A number of potential major wind farm zones have been identified in New Zealand. After consideration of resource management issues 14 "zones" are likely to contain sites suitable for wind farms. Prime sites satisfying environmental requirements may constitute 2.5% to 5% of each zone area.
From a 2001 EECA study on Wind Potential (ref EECA, 2001) using a lower end figure of 3% and wind distribution data for the zones, wind farm potential of over 12,600 GWh/yr is identified for wind speeds of 6 m/s or greater. This estimate is conservative. Sites are in both North and South Islands.
The EECA study provides base case energy levels for a range of wind speeds of 7 m/s and above.

	Energy (GWh p.a.)
Wind Speed (m/s)	(base case)
10	1,440
9	2,480
8	2,800
7	2,650
Total for potential sites 7 m/s and above	**9,370**

Supply Cost Data	**2012**		**2025**	
	MW			
	WACC = 5%	**WACC = 10%**	**WACC = 5%**	**WACC = 10%**
High Confidence	1,840	1,550	1,945	1,695
Medium Confidence	4,315	3,610	4,535	3,955
Low Confidence	6,165	5,150	6,470	5,650

Supply Cost Data	**2012**		**2025**	
	GWh/y			
	WACC = 5%	**WACC = 10%**	**WACC = 5%**	**WACC = 10%**
High Confidence	4,455	4,095	4,545	4,285
Medium Confidence	10,410	9,550	10,610	10,005
Low Confidence	14,875	13,645	15,160	14,300

ENERGY SUPPLY COSTS

Capital costs currently applicable to New Zealand - $1,900/kW to $2,100/kW range. O&M cost could be higher than overseas, possibly 2.5% of capital cost per annum ($40- $50/kW). Unit availability is expected to be lower than overseas units; difficulty with timing, maintenance and low wind speeds. Overall capacity factor could vary between 50% at high wind speed sites down to about 20% at 6 m/s sites.

Lifecycle costs depend critically on average wind speed and distribution. At a very good site (10-11 m/s) costs could be around 5c (5% discount rate) or 7c (10% discount rate) per kWh. Very sensitive to exchange rate fluctuations/forecasts which in effect change the capital cost/MW for wind turbines. Table below gives details of national energy supply cost data.

WIND SPEED - COST RELATIONSHIP at 5% discount rate

Site Wind Range m/s	Average Costs c/kWh 2002	2012	2025
6-7	10.75	8.50	7.25
7-8	7.75	6.25	5.5
8-9	6.25	5.0	4.5
9-10	5.5	4.5	4.0
10-11	5.0	4.0	3.5

WIND SPEED - COST RELATIONSHIP at 10% discount rate

Site Wind Range m/s	Average Costs c/kWh 2002	2012	2025
6-7	15.0	11.5	10.0
7-8	10.75	8.5	7.25
8-9	8.75	6.75	6.0
9-10	7.75	6.0	5.25
10-11	7.0	5. 5	4.75

While the following data is based on a similar MW-windspeed relationship as for the EECA information above, it should be noted that the high and medium confidence levels do not correspond to the “worst case” and “best case” EECA scenarios. The high confidence level figures below are a result of an assessment of a 80% possibility of uptake and the medium confidence level is based on a 50% possibility of uptake, with the significant influences being the ability to gain access to the best wind resources, and resource consenting outcomes.

Supply Cost Data Capital:$1,475/kW in 2012; $1,225/kW in 2025	c/kWh	2012 MW WACC = 5%	2012 MW WACC = 10%	2025 MW WACC = 5%	2025 MW WACC = 10%
High Confidence	2-4	-	-	170	-
	4-6	680	125	750	380
	6-8	475	520	425	510
	8-10	285	380	265	345
	10-12	205	250	175	230
	12-14	130	195	115	165
	14-15	65	80	45	65
Medium Confidence	2-4	-	-	395	-
	4-6	1,590	290	1,755	885
	6-8	1,115	1,210	990	1,190
	8-10	665	885	615	800
	10-12	485	580	405	540
	12-14	305	455	265	390
	14-15	155	190	110	150
Low Confidence	2-4	-	-	565	-
	4-6	2,275	410	2,505	1,265
	6-8	1,590	1,725	1,415	1,700
	8-10	950	1,260	875	1,145
	10-12	690	830	580	775
	12-14	435	650	375	550
	14-15	225	275	155	215

Supply Cost Data Capital:$1,475/kW in 2012; $1,225/kW in 2025	**c/kWh**	**2012**		**2025**	
		GWh/y			
		WACC = 5%	**WACC = 10%**	**WACC = 5%**	**WACC = 10%**
High Confidence	2-4	-	-	675	-
	4-6	2,310	500	2,245	1,405
	6-8	1,120	1,700	860	1,440
	8-10	505	945	400	730
	10-12	295	500	210	395
	12-14	155	330	115	235
	14-15	70	120	40	80
Medium Confidence	2-4	-	-	1,570	-
	4-6	5,395	1,165	5,235	3,280
	6-8	2,615	3,965	2,005	3,355
	8-10	1,180	2,200	935	1,705
	10-12	690	1,170	495	925
	12-14	365	765	270	550
	14-15	165	285	100	190
Low Confidence	2-4	-	-	2,245	-
	4-6	7,705	1,665	7,480	4,685
	6-8	3,740	5,665	2,865	4,790
	8-10	1,690	3,145	1,340	2,440
	10-12	985	1,670	705	1,325
	12-14	520	1,095	385	790
	14-15	235	405	140	270

FURTHER RESEARCH AND OTHER ISSUES	Grid Penetration Limits. Applicability of overseas costs data.

Level of penetration of wind power into New Zealand Grid is an issue that would benefit from further study. Large numbers of induction generators (using grid power to excite generator) might impose dynamic instabilities that should be examined. Wind-hydro storage integration also warrants investigation.
Reviewing the information on the performance of wind farm sized machines under New Zealand conditions would clarify cost data directly, allow correlation with overseas figures, and assist the development of local operating experience.

BIOMASS (WOODY)

ENERGY RESOURCE	Solar energy converted into dry or wood plant material suitable as a fuel for direct combustion or gasification.

Significant New Zealand biofuel categories with least cost energy potential:
1. *Forest Arisings* - slash, tops, etc. from exotic plantation harvest
2. *Wood Residues* - bark, sawdust, etc. from pulp/timber processing
3. *Fuelwood Plantations* - short rotation tree crops
4. *Domestic Firewood* - either from woodlots or scavenged material

SYSTEM ELEMENTS	Resource Production - growth, harvest and transport. Resource Conversion - treatment, storage and use.

Production
Arisings: By-product of exotic forest harvest. These are forest residues from landings and potentially including cutover. Currently an unused resource.
Processing residues: Bark, sawdust, shavings, etc. produced at site of wood processing. May be transported or used on site.
Fuelwood: Wood grown on short rotation, specifically for energy purposes.
Domestic firewood: Fuelwood merchants sourcing scrub, aged shelterbelts, etc. or commercial woodlots, householder scavenging of fallen trees, prunings, driftwood, etc.
Conversion
Biofuels can be directly burnt to provide heat for boilers producing steam/hot water, or for space heating, kiln firing, etc. Efficient mechanical fuel handling equipment is available.
Electricity can be generated via steam at an overall conversion efficiency of 30% for combustion or 40% for gasification (Biomass Integrated Gasification Combined Cycle).

SYSTEMS AND APPLICATIONS	Issues: Conversion plant location and sizing; combined use with other biofuels; integration with waste management.

Biomass conversion to heat can be competitive in the 2-40 MWth range for process residue fuel. Biomass has the advantage that it can be transported to the load.
Electricity generation, through cogeneration plant or combustion, may be possible for excess heat.
Plantation management can be integrated with land disposal of sewage and other liquid wastes. The waste treatment benefits can offset plantation establishment costs. Using wood-processing residues also mitigates waste management costs.

TECHNICAL STATUS	Key technologies for biofuel use are proven and commercial. Gasification is maturing. Emerging technologies (especially pyrolysis) are still at an early stage.

Arisings: Management to maximise fuelwood and pulp/sawlog production values is required. Whole tree harvesting is still new.
Fuelwood: Optimal fuelwood crop management is still being developed. Work on species selection and improvement would be beneficial. Suitable effluent application rates are not clear. Mechanical harvesting systems need to be developed.
Fuel: Significant New Zealand research has been undertaken on a site-specific basis. Confidence that competitive (under $3/GJ) fuels can be produced is now high.
Fuel handling: Fuel handling costs are significant. Technology is mature but costs and designs may be optimised if consistent fuel quality can be achieved.
Conversion Technologies: Combustion plant for heat or power is mature, with design confidence increasing with biomass experience. Some electricity generation via combustion may occur as owners look to maximise use of surplus heat.
Biomass gasification is being trialled internationally and is maturing (moving past the large prototype stage). It is expected to be competitive in the near term and has been used as the basis for projections in this report.
Cofiring with other fuels has been practiced with some environmental benefits possible if plant can be adapted to handle multi-fuels.
Cofiring of other fuels with biomass (if part of the fuel specification) can reduce the capital cost of the plant due to the higher energy content of coal and gas.
There is interest in developing liquid fuels via a range of means including the gasification route. These techniques tend to be experimental.
Cogeneration plant has been successfully installed and operated in New Zealand.

APPLICATION LIMITS AND SYNERGIES	A transportable fuel, still of variable quality.

Fuel quality has been inconsistent as it has been based on a changing waste product, principally wood processing waste, with major users being the wood processing industry.
CHH Biogrid is now offering biomass fuel products which could diversify uptake if quality can be controlled.
There may be competition for land use and competition for the waste products for alternative non-fuel applications, e.g. bark for garden products.
Biomass is widely spread so can be a fuel in most regions, though tends to be distant from major cities.
The fuel is ideally used by the forestry industry for drying or electricity.

CRITICAL FACTORS	Raw fuel costs, moisture content, transport.

The cost of obtaining, growing and harvesting fuelwood or collecting arisings, firewood and processing waste affects whether it is a viable fuel.
Moisture content affects combustion efficiency and net heat yield. Cheap drying means are advantageous.
Variability of fuel quality adds significantly to capital cost of plant.
Due to moisture content and low energy density, biofuels are expensive to transport. Their basic procurement cost is not a sound basis for a comparison with coal. Generally biofuels need to be used close to source. With pelletisation (or other fuel standardisation) and further treatment, this situation could change.

ENVIRONMENTAL ISSUES	Benefits: Greenhouse gas mitigation, waste reduction. Concerns: Sustainability re soils, ecosystem change.

Major benefit is carbon neutrality of biofuels.
Burning residues may mean less are landfilled where they decompose to methane. If tree crops are grown in association with waste disposal, there are water quality benefits and social (e.g. Maori cultural) benefits.
On some sites soil stability may be an issue, with tree harvesting. Long-term fertility effects of harvest are uncertain. Scrub clearance for domestic firewood or to expand exotic plantations raises habitat conservation issues but these can be managed. Biodiversity can be improved through plantation forestry.
Burning firewood in some residential zones may contribute to local air pollution concerns. Wood fuels are virtually sulphur free avoiding SO_2 emissions.
Burning firewood in domestic woodburners can be an efficient resource use compared with power generation with the same biofuel, and can be clean burning if properly designed.

NEW ZEALAND RESOURCE	Arisings/residues: Related to existing forests. Fuelwood/firewood: Need new plantations.

The only biofuels presently used to any degree are processing residues (equivalent to 13 PJ/y with a further 13 PJ/y from black liquor) and domestic firewood (equivalent to 5 PJ/y).
Biofuels have significant potential for growth: arisings and residues, as the harvest of exotic plantations increases, processing residues as timber production and processing increases, fuelwood and domestic firewood from energy plantations and woodlots.
Commercial development of wood fuel market is developing, e.g. CHH Biogrid.
Note that the projections shown below show a strong growth in the availability of process residues. This is highly dependent on the local processing of a significant proportion of wood on-shore rather than simply exporting timber in log-form. Without this processing, the following assumptions and costs become distorted.

Assessed National Resource Uptake

	Year 2012			**Year 2025**		
Source of Increase	**High Confidence**	**Medium Confidence**	**Low Confidence**	**High Confidence**	**Medium Confidence**	**Low Confidence**
	PJ	**PJ**	**PJ**	**PJ**	**PJ**	**PJ**
Firewood and Plantations	-	-	-	-	-	-
Process Residues	6	16	36	12	22	46
Arising (excl. cutover)	-	5	10	-	6	12
Arising (cutover)	-	-	27	-	-	33
Total	**6**	**21**	**73**	**12**	**28**	**91**

ENERGY SUPPLY COSTS	Procurement costs: Transport factor. Conversion costs: Depends on plant

Fuel costs: landing material around $2.7/GJ, landing material including cutover $3.4/GJ, processing residue around $0.25/GJ, fuel wood around $6.5/GJ, firewood $2.6-$26/GJ.
Uptake for heat expected across a range of boiler sizes. A 10 MW_{th} boiler currently has a specific cost of $0.54 M/MW (dropping to $0.48 M/MW after 2006) with O&M at 5% of capital cost per annum.
A 20 MWe power station would have a specific cost of $4.0 M/MW in 2012 and $3.3 M/MW in 2025 with O&M at 4% of capital cost per annum. Generation via gasification is considered to be the most appropriate technology assuming normal commercialisation process. Nevertheless, it is recognised that cogeneration based on combustion is still likely to play a part where advantage is wanted to be taken of surplus heat.
Cost supply data is given below for electricity and heat. Only a small portion has been assigned to heat (largely focussed on the forestry industry) but a major reassignment is possible from electricity to heat when the market for wood as a fuel gains wider acceptance. In practice, because of the cost curves shown below, uptake for electricity should be low, while uptake for heat should be high, as it is currently attractive for that use.

Electricity Generation Potential

Supply Cost Data	**c/kWh**	**Year 2012**		**Year 2025**	
		GWh/y		**GWh/y**	
		WACC=5%	**WACC=10%**	**WACC=5%**	**WACC=10%**
High Confidence	6-8	140	-	285	-
	8-10		-	-	-
	10-12	-	140	-	285
	12-14	-	-	-	-
	14-16	-	-	-	-
Medium Confidence	6-8	425	-	565	-
	8-10	1,130	285	1,345	285
	10-12	-	425	-	565
	12-14	-	705	-	1,060
	14-16	-	-	-	-
Low Confidence	6-8	4,245	-	4,665	-
	8-10	2,120	2,405	2,760	2,405
	10-12	635	2,265	990	2,545
	12-14	-	2,120	-	2,475
	14-16	-	635	-	990

Heat Supply Potential

Supply Cost Data	**$/GJ**	**Year 2012**		**Year 2025**	
		PJ/y		**PJ/y**	
		WACC=5%	**WACC=10%**	**WACC=5%**	**WACC=10%**
High Confidence	2-4	-	-	0.5	-
	4-6	2.8	1.5	5.0	3.3
	6-8	0.4	1.3	0.7	2.2
	8-10	-	0.4	-	0.7
Medium Confidence	2-10	No additional resource			
Low Confidence	2-10	No additional resource			

Note that heat supply costs are competitive with fossil fuels for all options considered.

FURTHER RESEARCH AND OTHER ISSUES	Energy demands versus sources. Better harvesting, drying and conversion costs. Input/benefits for domestic firewood use.

Now need to disseminate the information about the woody biomass resource. There is a need for standardised products to be sold on the open market.
Attention needs to focus on heat as opposed to power generation.
A close watch needs to be kept on gasification technology commercialisation

BIOMASS (LANDFILL GAS)

ENERGY RESOURCE	Methane from anaerobic decomposition of mixed municipal solid waste (MSW) placed in landfills
Typically 60% to 70% of MSW is organic material; mostly paper but also food wastes, etc. Compacted and buried in landfills it decomposes to produce landfill gas; methane and carbon dioxide and trace gases. The gas can be collected and used as a fuel to provide heat and power.	

SYSTEM ELEMENTS	Landfill management, gas extraction, treatment and use
Landfill management: Site selection to get high volume to surface ratios; impermeable boundaries; management of water content; selection and segregation of wastes; progressive installation of gas drainage. *Gas extraction:* Drainage wells vertical (retrofit) or horizontal (integrated with landfilling); passive extraction, or active by applying negative pressure with extractors; above ground piping systems to convey gas. *Gas treatment and use:* Separation of condensate and gas and reinjection of condensate; scrubbing to remove harmful trace gases; carbon dioxide reduction depending on end use; end use in variety of heat or power plant.	

SYSTEMS AND APPLICATIONS	Landfill versus biofills, variable development scale, heat and power and transport fuel applications
Biofills are managed to maximise methane production and collection for energy purposes whereas with landfilling, gas extraction is motivated by concerns over safety and environmental issues. Landfill sizes and gas yield vary enormously. Development can be scaled to match the available resource. Staged development feasible as landfilling progresses. Power plant from 1 MW to 50 MW in use, though is more common at the lowest end of the scale for New Zealand situations. Treated gas can be used to provide heat and power for boilers, gas turbines and reciprocating engines, to fuel kilns and to provide CNG for vehicles.	

TECHNICAL STATUS	Plant technology proven and commercial, resource assessment and landfill management capabilities still on a learning curve
Landfill gas extraction and use practised at a large number of sites including at least four in New Zealand. Ability to predict gas supply from existing landfills and the performance of biofills is still being refined. The effect of manageable factors in methane production and diffusion rates is the subject of R&D.	

APPLICATION LIMITS AND SYNERGIES	Resource size, supply variability. Environmental benefits
Landfill gas yield and reliability of supply has to match end use needs. Power supply may fluctuate. Degree of gas storage can provide a buffer at a cost. Main synergy is with environmental/public safety concerns. Gas drainage may be required to deal with these concerns anyway. Instead of flaring gas, utilisation provides an additional environmental/economic benefit. There are some synergies between landfilling, geothermal energy and woody biomass with some trials being undertaken in the use of geothermal heat and fluid to enhance methane production from wood waste landfills.	

CRITICAL FACTORS	Gas resource relative to landfill volume. Adjacent heat or power need. Safety standards
Gas supply and demand issues are critical. Public safety standards can increase costs for gas drainage. Nearby demand for heat, close proximity to gas or power reticulation network. There is a trend away from landfilling that will limit future opportunities.	

ENVIRONMENTAL ISSUES	Low impact adjunct to landfilling. Mitigates gas emission, migration problems
Landfilling MSW creates a wide range of environmental impacts. Collecting the landfill gas from a site adds a few additional minor impacts, while significantly reducing the problem of gas migration and escape. Utilising landfill gas means noise from plant and occasional flaring, and the visual effect of civil works; comparable to other activities in a light industrial zone. Methane is a potent greenhouse gas having 21 times the impact of CO_2. Its explosive nature can create a public safety hazard if it migrates from the landfill site. Methane can also damage vegetation on and around sites and create odour problems. Landfill gas collection and use mitigates these concerns.	

NEW ZEALAND RESOURCE	No reliable estimate. In 10 years could be around 170 GWh. Sensitive to future waste management strategies

There is no reliable estimate of the utilisable landfill gas resource in New Zealand. Current landfill emissions of methane are estimated to be around 174 x 10^3 m^3 per year with an energy value of 9PJ.

Strategies towards waste management are changing and are likely to reduce the potential landfill gas resource in the medium to long term. Paper recycling, mulching and use of yard wastes, composting, waste incineration will all act to reduce landfill gas supplies.

Landfill gas can be used for power generation via a variety of plant. The average efficiency of a range of plant could be 30%. Current electricity generation is about 74 GWh/year with negligible heat use.

Allowing for utilisation at major population centres only, inefficiencies in collection and the likely reduction in supples with time (against a trend of increasing collection efficiency), a further 100 GWh (equivalent to 13 MWe) of generation is projected. There are firm plans for an additional 1 MW unit at Redvale, and 1.4 MW may be possible at Green Island.

ENERGY SUPPLY COSTS	Increasing New Zealand development experience. Relatively low cost supply - 5 to 6c/kWh

Capital costs are low in comparison with other renewable technologies (about $2,150/kW including gas collection or $1,450/kW excluding collection after 2006). Exclusive costs are thought to be reasonable as a measure of collection and flaring are a general requirement for consents. Given the pressures due to greenhouse gas concerns, gas collection and flaring may be seen as essential in future.

Overall lifecycle costs based on limited New Zealand experience are projected to be 5 to 6 c/kWh. These costs could be taken as around 2 c/kWh lower if an institutional requirement for gas collection and flaring become the norm (environmental control). New Zealand costs correlate well with overseas experience.

LANDFILL GAS SUPPLY SUMMARY

Confidence Levels	c/kWh	Year 2012		Year 2025	
		GWh/y		GWh/y	
		WACC=5%	WACC=10%	WACC=5%	WACC=10%
High Confidence	2-4	18	8	18	8
	4-6	82	18	82	18
	6-8	-	74	-	74
Medium Confidence[1]	2-4	100	8	100	8
	4-6	-	92	-	92
	6-8	-	-	-	-
Low Confidence[1]	2-4	100	8	100	8
	4-6	-	92	-	92
	6-8	-	-	-	-

1. Medium and low confidence level resources are not additional to the high confidence level resources but represent the opportunity if collection costs are netted off the total capital cost

FURTHER RESEARCH AND OTHER ISSUES	Gain operational experience. Improve site survey methods

The main priorities for New Zealand are to develop and improve expertise in the survey of landfill sites for energy potential; and to gain experience with the operation of landfill gas-energy systems. Dissemination of information and increased consideration of landfill gas energy issue in site selection is desirable.

BIOMASS (OTHER)

ENERGY RESOURCE	Anaerobic decomposition of purpose grown crops or organic wastes produces biogas - methane plus carbon dioxide.
Purpose grown crops: Green crops used directly as biogas feedstock, e.g. kale, oats, some grasses, and possibly sugar beets. Generally these are not considered economic. *Organic wastes:* Produced from meat processing plants, wool scours, dairy plant, vegetable processing plants, intensive farming of pig, poultry and livestock, crop residues, sewage and water treatment plant waste.	

ELEMENTS AND SYSTEMS	Resource procurement, bio-gasification, biogas use and sludge disposal.
Procurement: Crops grown by farmers under contract to supply biogas plant. Predetermined rotation established to ensure steady supply. Crops harvested and transported to digestion plant. Wastes are generally used at site of generation. *Bio-gasification:* Feedstock comminuted if necessary (may be done at harvest). Digested in a reactor or gasified and the gas collected and stored in low-pressure bags or gasometers. *Biogas use:* Biogas can be piped from farm digesters to a central processing plant (or feedstock transported to central gas producing plant). Gas is scrubbed if necessary, and used to supply reticulation systems, to provide heat or power or CNG. *Sludge disposal:* Digester sludge is returned to farmland as a fertilizer and soil conditioner. *Organic Waste:* Waste collected and digested anaerobically, gas collected and used.	

TECHNICAL STATUS	Green Crops - crop storage, climatic contingencies. Organic wastes - proven and commercial hardware.
Combustion and anaerobic digestion plants are a proven technology. They are found in almost every major industry in New Zealand. Crop storage to provide a further buffer over rotation conditions or other natural disasters reducing crop production/energy output unclear.	

APPLICATION LIMITS AND SYNERGIES	Synergies with pollution and waste mitigation. Limits are feedstock reliability, infrastructure.
Anaerobic treatment of wastes is cost competitive with aerobic processes. Where resource consent requires waste treatment before discharge, the cost of biogas from waste digestion is effectively nil, apart from collection transport. Waste digestion means less water pollution, especially from nutrients and reduced sludge volumes to dispose of. Returning sludges to agricultural land reduces fertilizer demand. No New Zealand experience with legal and technical infrastructure for the long-term supply of green crops. Lack of a CNG distribution system and natural gas reticulation in the South Island limits the markets for biogas there, and hence possibly the scale of development based on green crops. Crop reliability and hence continuity of energy production is an issue that could affect applications and economics. Some crops such as beets are suitable for storage and could provide a degree of buffer.	

CRITICAL FACTORS	Public policy re pollution and waste disposal, and greenhouse emissions. Type and amount of wastes/feedstock. Competing land use.
If waste generating industries are required to treat effluents before discharge and minimise solid wastes then anaerobic digestion becomes a viable option. Using the gas created to produce heat or power or as CNG may then be a viable next step. Waste and green crop digestion is affected by economies of scale. Obtaining an adequate amount of feedstock is critical. On-site wastes could be augmented with compatible material brought in. Large-scale crop feedstock would have to compete with other crops. The retention time required for digestion depends on wastes characteristics. It can vary from less than 1 day to around 30 days for some wastes. Longer retention times reduce the throughout per unit of reactor size and hence increase the costs. Organic concentration is an issue. Some wastes, such as dairy shed effluent, are too dilute with water to make viable feedstock. Capital and O&M costs of gasifiers need to be significantly reduced to compete with other forms of heat or electricity generation.	

ENVIRONMENTAL ISSUES	Significant benefits from waste digestion. Crop feedstock- fertility and pollution issues.

Digesting wastes reduce the impacts of effluents and solid waste disposal. Methane combustion reduces impact on air.
Growing crops for biogas production will displace other land uses. It also raises a sustainability issue re fertility. However, returning sludges to land mitigates this, while also dealing with the solid waste issue. Residual pollution concerns from effluents or excessive sludge loadings on cropland may remain.

NEW ZEALAND RESOURCE	Crops - Each 10,000 ha = 100 GWh Wastes - Gross potential less than 200 GWh/yr. Waste feedstock too diverse and small to contribute any significant power generation.

Crops for biogas production would have to provide a better return to the grower than those from other crops. In practice, this will require a price which would lead to unit costs for electricity generation in excess of the 15c/kWh cutoff. There is no reliable estimate of the amount of electricity that could be obtained from digestion of purpose-grown crops in New Zealand. While land suitable for large scale cropping is available in several parts of New Zealand, the most extensive area is on the Canterbury Plains. Average crop yield is expected to be around 16 tonnes of dry matter per ha per year. Digestion would yield 132 GJ/ha/yr of gas. For each 10,000 ha of crops, around 100 GWh of power can be generated (conversion efficiency 30%).
Four major types of wastes are available and suitable for digestion: On-farm animal effluents (e.g. piggery wastes), on-farm crop residues not consumed for stock feed, food processing wastes (vegetable, fruit, meat and fish), land components of the mixed municipal waste stream. The latter is dealt with in the landfill gas renewable energy package.
Around 8.5 MJ of gas can be obtained from each oven dry tonne of waste digested. This resource however is spread over the whole country and dispersed across a wide range of conversion unit size and circumstances. In some cases the fuel would be used for heat only, flared or not produced, and aerobic processes used instead.
Meat processing tends to take place on a large scale suitable for economic waste digestion land power production. The power potential from this source is around 40 GWh/yr.
The remaining sources such as poultry and piggery wastes, are estimated to have an electricity generation potential of around 20 GWh/year.

ENERGY SUPPLY COSTS	Crops - $11/GJ plus transport, electricity 16 c/kWh minimum.

The crop feedstock for biogas production can be grown for around $11/GJ. Transport costs could add up to another $1/GJ. The capital cost of reactors to produce biogas, power generation plant are around $3,500/kW for large-scale plant. System O&M costs are relatively high at 2.5 c/kWh. Unit costs of around 16 to 25 c/kWh are expected.
Anaerobic waste digestion the biogas can be considered as a free fuel. Further more, digesting wastes saves the energy that would have been used for aerobic treatment. Capital costs for large scale generating plant are $3,000/kW and O&M costs are moderate. Small-scale digesters will produce more expensive electricity, 15 c/kWh or more.

BIOGAS SUPPLY COST DATA
(Moderate-high capital and O&M costs, offset by high capacity factor)

	c/kWh	Year 2012		Year 2025	
		GWh/y		GWh/y	
		WACC=5%	WACC=10%	WACC=5%	WACC=10%
Medium Confidence	4-15	-	-	-	-

FURTHER RESEARCH AND OTHER ISSUES	

Determine the potential to convert existing waste treatments to anaerobic digestion.

SOLAR HEATING

ENERGY RESOURCE	Sunlight used for water heating.
Heat can be derived from sunlight via active systems for water heating. Low temperature systems used for heating can use not only direct (beam) but also indirect (diffuse) solar radiation. Heat can also be obtained on cloudy days. Note: Solar thermal technology (high heat) and photovoltaic power (electricity generation) are not covered in this section.	

SYSTEM ELEMENTS	Simple technologies for resource collection, storage, transport and end-use.
Collector: An element that absorbs solar energy and transmits it to a medium that can be used to convey the energy to where it is used. *Transport medium:* A fluid or gas that transfers the heat from the collector to the end-use site. *Motivating force:* A means to shift the transport medium between the collector and the end-use site. *Storage:* A means of smoothing out fluctuations in solar supply, such as an insulated water tank.	

SYSTEMS AND APPLICATIONS	Passive and active solar systems. Integrated vs retrofit. Applicable to on-site energy needs.
Active systems have a mechanical motivating force (e.g. pump) to move the transport medium and operate any end-use heat exchange. Passive systems rely on thermal gradients to move energy. Both active and passive hot water heating can be retrofitted. Passive and active solar systems do not lend themselves to large-scale production of energy for transmission to other sites. They are usually sized to meet on-site needs. Applications include water heating for domestic and other buildings, and industrial and agricultural processes (e.g. crop drying).	

TECHNICAL STATUS	Mostly proven and commercial technologies. Established New Zealand design and operational experience.
Passive and active hot water heating: Fully commercial, but would benefit from further promotion and demonstration projects to aid marketing. There are a number of New Zealand manufacturers with quality products.	

APPLICATION LIMITS AND SYNERGIES	Dispersed, robust source. Limited by scale, backup supplies, and replacement of existing cylinders.
Limited to on-site demands. Robust, with little maintenance. The system provides a degree of independence from grid or network supplies of electricity and natural gas. Some system boosting or backup with electrical supply is usually needed for some designs. System efficacy and hence need for power backup reduced by users adjusting energy demands, by amount, time of day, etc. and providing input into system management. The cost of installing in new buildings generally lower than retrofits.	

CRITICAL FACTORS	Avoided cost of conventional hot water cylinder.
Economics determined by ability to avoid cost of conventional hot water cylinder installation or replacement. Lack of knowledge of systems available (builders, plumbers, architects, home owners).	

ENVIRONMENTAL ISSUES	Virtually no impacts.
Use little or no more materials than conventional construction. Collectors can be integrated into architecture.	

NEW ZEALAND RESOURCE	
The average benefit (2,500 kWh/yr) depends on a number of factors, but does not vary significantly with geographic region. Presently approx 16,000 solar water heating (SWH) units are currently thought to be installed. Estimated 1,200 new systems being installed each year. Currently 21,000 dwellings built each year.	

REGIONAL VARIATION - ANNUAL GLOBAL ENERGY PER SQ.M.	
Region	**kWh/m²/yr**
Kaitaia	1,469
Paraparaumu	1,403
Gisborne	1,497
Christchurch	1,367
Invercargill	1,292

ENERGY SUPPLY COSTS

An indicative energy cost per system is 7-10 c/kWh based on a 5% WACC as discount rates are not normally applied to domestic housing.
By 2005 10,000 systems per year could be being installed. By the year 2012 up to 100,000 new homes could have solar systems. The resulting energy savings might be of the order of 25 GWh/yr.
Approximately 60,000 domestic sized electric hot water cylinders are sold each year, about half for new homes and half for replacement. Installation of SWHs in new homes may be 5-10% cheaper than retrofits. Typical costs for minimum investment systems are around $3,000 to $3500 per unit. Annual energy savings per unit could be 2,500 kWh on average.

Possible Energy Production / Cost Data

	c/kWh	By Year 2012			By Year 2025		
		GWh/y			GWh/y		
		WACC = 0%	WACC = 5%	WACC = 10%	WACC = 0%	WACC = 5%	WACC = 10%
High Confidence	4-6	-	-	-	-	-	-
	6-8	100	-	-	200	-	-
	8-10	110	100	-	330	200	-
	10-12	5	110	-	10	330	-
	12-14	-	5	100	-	10	200
	14-15	-	-	110	-	-	330
Medium Confidence	4-6	-	-	-	-	-	-
	6-8	100	-	-	250	-	-
	8-10	160	100	-	290	250	-
	10-12	5	160	-	5	290	-
	12-14	-	5	100	-	5	200
	14-15	-	-	160	-	-	290
Low Confidence	4-6	-	-	-	-	-	-
	6-8	150	-	-	300	-	-
	8-10	150	150	-	360	300	-
	10-12	5	150	-	5	360	-
	12-14	-	5	150	-	5	300
	14-15	-	-	150	-	-	360

FURTHER RESEARCH AND OTHER ISSUES

Barriers to uptake, Market development, Government support mechanisms.

Research on barriers to uptake.
Information made available to builders, plumbers and architects.
Establishment of quality standards for manufacturers and installers.
Establishment of national marketing programme.
Identification of most effective kick-start mechanisms.
Identification of high profile hype promotion opportunities.

SOLAR (PHOTOVOLTAICS)

ENERGY RESOURCE	Sunlight is converted into direct current electrical energy via semiconductor materials
Maximum intensity of solar radiation at sea level is around 1kW/m^2. The amount of solar energy that falls on a square metre ranges from 800 to 2,600 kWh per year depending on location. PV technology produces electricity by converting the energy in sunlight into voltage or current without mechanical means.	

SYSTEM ELEMENTS	Solar cells, modules and arrays, concentrating/ tracking devices. DC conversion or storage.
Solar cells: Semiconductor materials based on either thick or thin technology. Crystalline gallium arsenide cells have highest efficiency (35%) but cost limits application. Most industrial cells are silicon based (15% efficiency). *Modules and arrays*: Typically around 100 cells are joined to form a square metre module. Groups of modules are physically and electrically connected in series to form arrays producing the required output voltage. *Energy concentration*: Flat plat modules can be installed on tracking devices to follow the sun. Concentrating modules use optical devices to focus light onto cells – they can also be made to track. Electricity conversion: DC current can be converted to AC current for wider application, or the DC energy can be stored in batteries.	

SYSTEMS AND APPLICATIONS	Stand alone applications.
Stand-alone: Often remote locations. Usually combined with battery storage. Increasingly being used to power consumer products and appliances, such as outdoor lighting. *Grid energy*: Converted to AC and fed to grid or used to substitute for part of grid supply.`	

TECHNICAL STATUS	Not mature. Significant research overseas
Not a mature technology. Involvement of oil companies has resulted in new large-scale production plant in Australia, Europe and USA which will realise economies of scale. Further technical advances relate to production of large area polycrystalline, microcrystalline and amorphous thin films in both silicon and other semiconducting materials. Significant research being done overseas.	

APPLICATION LIMITS AND SYNERGIES	Time of day limitations. Requires storage batteries.
Output limited to daylight with requirement for storage for night use. Impractical to have storage for large applications. Production occurs on rainy or cloudy days. Peak electricity output does not coincide with peak demand requirements. Backup supply required if no/limited storage. Modularity of PV arrays provides flexibility re matching electricity demand. Hybrid systems such as PV plus diesel, or wind generators with battery storage. Can be easily integrated into new and existing buildings. Unobtrusive.	

CRITICAL FACTORS	High cost for grid power. Ideal for niche opportunities.
Main impediment to uptake is cost relative to grid electricity prices. Initial uptake principally through niche applications. PV suitable at remote sites where cost of alternatives is high.	

ENVIRONMENTAL ISSUES	No major concerns in use.
A freely available resource with no adverse environmental issues. Green energy perception.	

NEW ZEALAND RESOURCE	Significant resource available. Little existing use.
Installed capacity estimated (2001) at between 800kW and 1MW with annual production of ~1,280 MWh. Available energy on flat surface of 1,400-1,500 kwh/m^2. Average 150m^2 house roof intercepts 2.2x 10^8 Wh pa of sunlight. International growth has been exponential with similar trends likely within NZ	

Year	2012			2025		
Capacity	**MW**	**GWh/y**	**Market Share (%)**	**MW**	**GWh/y**	**Market Share (%)**
High Confidence (25%/a growth)	13	19	0.04	230	340	0.6
Medium Confidence (37.5%/a growth)	40	58	0.13	2,500	3,700	6.4
Low Confidence (45%/a growth)	77	110	0.24	9,600	14,000	24.0

ENERGY SUPPLY COSTS	$10,000/kW. Costs reducing. 31 c/kWh in high sunshine areas.

>25 year lifetime. (20 years manufacturers guarantees).
Capital costs starting around NZ$10/Wp but dropping rapidly in price due to maturation and exchange rate effects.
Costs reducing with increased economies of scale.

	Year 2012		Year 2025	
	c/kWh		c/kWh	
	WACC=5%	**WACC=10%**	**WACC=5%**	**WACC=10%**
Insolation Value =1,300kWh/m^2/y	31	48	14	21
Insolation Value =1,500kWh/m^2/y	27	42	12	19

Analysis was based on a 15% increase in insolation value due to favourable panel orientation.

FURTHER RESEARCH AND OTHER ISSUES	

Monitoring developments coming from Australia and adapting to niche opportunities will increase uptake and economies of scale will reduce costs.

APPENDIX B: DATA REPORTS

CHAPTER 1 - HYDRO POWER

1. TECHNOLOGICAL INFORMATION

1.1 ENERGY RESOURCES

Today's environment for hydroelectric development is very different from that which applied during the 1960s to 1980s. Previously dominated by state owned agencies that generally constructed on a "cost-plus" basis, it is now very much "free-market" with recent and future projects commercially driven. Also the expectation of both the government and the public that a state-owned electricity generator would "meet demand" no longer applies. These changes affect the public acceptability of new hydro projects.

Public acceptance of a potential hydroelectric development is also more difficult today due to society's changing environmental and conservation attitudes. The statutory approval requirements through the Resource Management Act are more stringent and have a lower certainty of success. However, this by no means precludes hydroelectric development. There are many opportunities that are considered to be quite consentable, if a robust consenting process is followed.

It is believed that many schemes previously considered to be not viable for economic or environmental reasons can be made viable by the adoption of a different technical and commercial approach, e.g. water extraction rather than river impoundment.

There is a significant level of hydro opportunity that is technically available. However, economical and technical feasibility are dependent on topography (storage and head), meteorological conditions (rainfall and river flow), site location, engineering issues, environmental impacts, and consentability.

This report includes run of river and out of river schemes but does not include pumped storage (but this is briefly discussed on page 46), potential under 3 MW, schemes in National Parks, or those sites covered by Water Conservation Orders, Stewart Island or the Chatham Islands.

The undeveloped potential identified in this assessment is considerably less than previously reported. This is due largely to the elimination of potential schemes which are considered "unlikely to be consentable" due to their perceived adverse environmental or social impact and the view that many of the larger schemes need to be reduced in capacity to make them economically viable. In addition, some of the prospects included in earlier assessments have in the interim been developed.

1.2 SYSTEM ELEMENTS

The development cost of projects includes all civil works, plant and equipment, local transmission line, infrastructure, resource consent, and mitigation costs.

1.3 SYSTEMS AND APPLICATIONS

Hydroelectric generation uses fresh water resources available in New Zealand.

Along with consumptive uses such as irrigation and water supply, New Zealand's fresh water resources are a resource strongly associated with recreational activities ranging from swimming, water skiing, jet skiing and flat water canoeing to white-water rafting, canoeing, and jet boating.

Fishing and fisheries, both recreational and commercial are also very significant users of fresh water as are flora and fauna.

1.4 TECHNICAL STATUS

Hydropower technology is a proven commercial and mature technology. The conceptional use of the technology is however being continually refined, i.e. better techniques for site selection, plant design and construction; innovative civil works, e.g. modular design (particularly for remote sites), improved generating plant and controls, and standardisation of equipment. Improvements in turbines and draft tubes have revitalised old marginal stations and improved power output from others. Embedment benefits are significantly enhanced with schemes that have water storage capacity.

1.5 APPLICATION LIMITS AND SYNERGIES

Hydro investment can be combined with irrigation projects and other water supplies, flood protection schemes, etc. which through shared infrastructure can improve the project economics.

Implementation of any hydro scheme will be constrained more or less by the resource consent requirements under the Resource Management Act.

The ability to acquire the rights (purchase, easement, share issue, etc.) to the land necessary for the scheme is the other significant potential constraint. A fundamental premise of this assessment is that the land can be acquired. The situation relating to land has changed in that, prior to 1987, Government policy was that farmland should not be flooded for the purposes of hydroelectric development, whereas today, that policy no longer applies. However, today the greater difficulty relates to encroachment on native forestland that has been protected by various means.

It is believed that most if not all of the large scale potential has been identified, although variations are continually being developed. Such work has in the main been undertaken by or for government agencies and is well-recorded and public knowledge. However, smaller scale schemes have often been studied by local power companies and in some cases knowledge of them is not widely known.

The "consentability" criterion is the reviewers' judgement-based measure of the likelihood of being able to obtain the necessary resource consents for the project to be implemented. Schemes that are considered "unlikely to be consentable" are excluded from the totals of "Realistic Potential". In other words, regional and national summaries only include those schemes that are considered to have a "reasonable" likelihood of being able to get resource consent. For example, some rivers have had a National Water Conservation Order applied to them subsequent to the last investigation report or fall within a National Park or area of special environmental or recreational importance/protection. Schemes so affected are generally deemed to be "unlikely to be consentable" and therefore are excluded from the summary of "Realistic Potential".

Where schemes impact on another (i.e. they are mutually exclusive), the summary of “Realistic Potential” will include only the likely best scenario.

The reliability of the information for individual schemes varies greatly depending on the level of investigation and reporting.

Recent studies by some potential developers have focused more closely on optimising the unit cost of generation by reducing the installed capacity, applying “value management” principles to reduce costs without reducing functionality, and by undertaking more comprehensive cost estimates involving civil contractor and machinery supplier input. The result generally has been a dramatic reduction in unit cost of generation, more than 50% in some cases.

This analysis demonstrates the significant advances that have been achieved in lowering the cost of generation of the hydro schemes studied during the recent (1990s) phase of investigations. This is attributable to a number of factors such as a move away from a philosophy of maximising resource utilisation (i.e. high installed capacity/low plant factor) to one of optimising unit cost of generation, lower costs of generation equipment, more cost effective design, technological advances in both the permanent works design and construction equipment and productivities, and a more competitive construction industry.

However, it is likely that a number of potential schemes have not been subject to the process outlined above (or if they have, the results are most unlikely to be in the public domain).

Scheme design will generally be based on the level of residual flow that will be required to be maintained in the river during times of water storage or power station operation. In recent years the residual flow requirements have increased with a resultant decrease in potential generation capacity.

Irrigation schemes and hydroelectric generation schemes are complementary uses of a water resource and when combined can increase the overall value of that resource. Provision of irrigation also has the potential to contribute significantly to the local community support for the project and hence to its consentability. The evaluation of the irrigation potential is very dependent on local factors such as soil type, rainfall patterns and the potential to modify the land use.

1.6 CRITICAL FACTORS

The main critical factors are resource location, engineering and environmental issues. Remote locations increase construction costs including transmission lines costs and power losses. Location plus head, flow, geological conditions, etc. affect the cost per installed capacity. Flow, storage and capacity choice affect capacity factor, or degree of utilisation, the other key economic element.

Although obtaining resource consents will be a significant feature of any future hydroelectric development, many of the identified opportunities are considered to be realistically consentable if a sound public consultation programme is undertaken.

There is a growing demand for water for urban supply and irrigation and multi-use water projects are expected to become more prevalent in line with international trends. The value of water generally is showing a rapidly increasing trend. It is expected that the multi-use approach has the potential to improve the economic viability of many hydroelectric generation projects. It has the added benefit of winning local community support and thereby being a major benefit in achieving resource consents.

1.7 ENVIRONMENTAL ISSUES

Hydropower development affects catchment hydrology and habitats.

Internationally, there is some resistance to hydro development as it often involves flooding of large areas of land. In New Zealand, hydro schemes are often located in steep-sided valleys with little storage and minimal effect on nearby land use. Thus international concerns are not transportable to New Zealand.

Hydroelectric generation is mostly seen as a clean and non-polluting means of producing electricity. It is generally a safe power source with only a few significant failures internationally. Land stability and induced seismicity may be issues.

Hydro development does, however, alter the nature of rivers and modify or prevent other uses and values of the river such as scenic values, fish use, wildlife habitats and some recreational uses. Sediment balances can be altered and ecological effects may extend to coastal environments. Increased residence time from impoundment can create water quality problems, especially where inflows carry high nutrient loads.

At the same time hydropower development does create new recreational facilities, different habitats, and form new lakes which may contribute to landscape values. Construction impacts can affect local communities for many years. These can be managed and townships can be left with improved community facilities.

Development is a matter of balancing the losses with the gains. Success often depends on good public consultation and involvement.

2. NEW ZEALAND RESOURCE INFORMATION

2.1 INFORMATION SOURCES

This report draws on a range of unpublished work previously undertaken by the reviewers. That information is based on a full review of previously published reports on hydro schemes and the judgement and the reviewers after having personally been involved in assessing most hydro schemes proposed in New Zealand.

2.2 THE LOCATION OF RESOURCES

Table H1 shows that most of the high/medium confidence remaining hydro resources are located in the South Island with almost 75% being in the West Coast, Canterbury and Otago Regions. This will have associated additional transmission costs, particularly from the West Coast.

Table H1: New Zealand Hydro Resources up to 15 c/kWh at 5% WACC

Region	No. of Potential Schemes	Potential for Development (MW)			Potential Energy Output GWh/y
		High Confidence	Medium Confidence	Low Confidence	
Northland	3	-	5	17	74
Auckland	-	-	-	-	-
Waikato	10	8	24	81	407
Bay of Plenty	14	25	128	278	1,276
Gisborne	4	12	42	42	188
Hawkes Bay	8	51	174	174	869
Taranaki	5	3	25	51	240
Manawatu-Wanganui	8	53	144	144	704
Wellington	8	-	32	41	186
Nelson-Marlborough	8	35	59	119	578
West Coast	27	-	373	968	4,404
Canterbury	21	919	927	1,181	6,455
Otago	16	-	370	985	4,907
Southland	5	-	-	157	650
Total New Zealand	**137**	**1,106**	**2,302**	**4,237**	**20,938**

Table H2: New Zealand Hydro Resources up to 15 c/kWh at 10% WACC

Region	No. of Potential Schemes	Potential for Development (MW)			Potential Energy Output GWh/y
		High Confidence	Medium Confidence	Low Confidence	
Northland	-	-	-	-	-
Auckland	-	-	-	-	-
Waikato	8	8	24	44	252
Bay of Plenty	13	25	108	258	1,196
Gisborne	3	12	37	37	163
Hawkes Bay	7	51	154	154	779
Taranaki	4	-	22	48	230
Manawatu-Wanganui	8	53	144	144	704
Wellington	1	-	6	6	25
Nelson-Marlborough	6	35	48	83	408
West Coast	24	-	373	758	3,414
Canterbury	14	919	919	1,047	5,755
Otago	13	-	364	869	4,335
Southland	2	-	-	85	370
Total New Zealand	**103**	**1,103**	**2,199**	**3,532**	**17,631**

2.3 THE QUANTITY OF THE RESOURCE

In this table confidence levels based largely on consentability have been assigned to the "Potential for Development", noting that schemes where there are likely to be significant geotechnical related risks leading to cost uncertainty, have not been included.

High Confidence	Attractive, with few apparent issues
Medium Confidence	Attractive, but with some significant issues
Low Confidence	Possible, but with many issues

Tables H1 and H2 show that the major resource opportunities are available in the South Island for all three confidence levels.

2.4 VARIABILITY OF SUPPLY

Unlike overseas schemes, most hydro schemes that have been built or may yet be built in New Zealand have little storage and therefore reduced flexibility of operations. This is an area where improvements to existing schemes may be obtainable. It is possible that some pumped storage schemes may become economic and be constructed during the period covered by this report. While not directly increasing the energy supply availability they provide the opportunity for thermal plant to continue generating during low demand periods, thus contributing to a short-term reduction in the variability of supply.

2.5 CURRENT UTILISATION OF RESOURCES

The currently installed capacity of just on 5,000 MW is approximately 50% of the total developable resource. The additional potential resource at an estimated upper limit of 15 c/kWh (10% WACC) is about two-thirds of the developable resource .

Enhancements of existing facilities occur to provide additional energy, e.g. Manapouri second tailrace tunnel.

2.6 INFRASTRUCTURE OBSTACLES

The most significant obstacle is access to land.

In some cases, transmission constraints may have an impact on development, particularly for projects located on the West Coast of the South Island.

Hydro sites have a range of accessibility. While some are readily accessible by the existing roading system, a large number are off the beaten track and significant expenditure on roading upgrades or new roading of sufficient capacity for construction loads would be required.

Accommodation for the construction workforce is a related issue. While some hydro sites are readily accessible from larger population centres where a workforce can be housed, others may require purpose built accommodation.

2.7 VIEW ON UPTAKE

Long lead times, risk in geotechnical areas, cost and time overruns, consenting issues, and uncertainties all contribute to a reluctance to invest in the use of a renewable resource. A significant amount of effort/investment is required to determine the areas of risk and how best to manage them. As a result, the uptake will likely be less than the c/kWh might indicate.

Small out-of-river schemes which may involve less upfront investigations expenditure are likely to be considered viable in the future particularly when linked to irrigation on district water supply requirements.

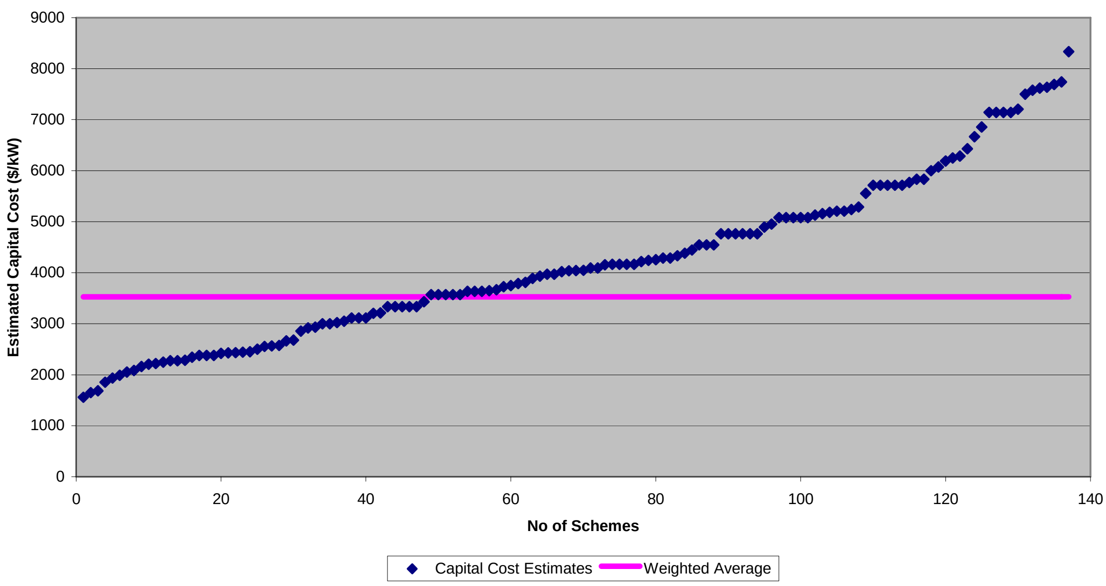
3. ENERGY SUPPLY COSTS

3.1 CAPITAL AND OPERATING COSTS

The assessed costs include not only direct construction costs but also the indirect costs such as establishment, construction infrastructure, engineering and project management costs.

Figure H1 shows the current range of cost/kW for the schemes covered in this report. No clear cost relationship to size is evident.

Figure H1: Current Capital Cost Estimates for Potential Hydro in New Zealand



Note that the costs include all local transmission costs (usually to the nearest Transpower substation) but not additional costs of possible expansion to the existing grid.

For the annual operating and maintenance costs, experience shows that these can generally be adequately represented by a relationship with the capital costs to provide an estimate for the annual O&M costs.

The station economic life is assumed to be 50 years.

The load factor assumed for converting capacity to output varies for each scheme. Overall the average is about 56%. No allowance is made for the line losses in the transmission system.

Major repairs or refurbishments to individual stations cannot be predicted and in the overall system can be considered to be included in the regular O&M costs.

3.2 SENSITIVITY

A check of the sensitivity of the above results to changes in basic parameters provides a confidence factor. The parameters chosen were discount rate, construction costs, and construction period and plant factor. The results are shown in the following four tables:

Table H2: Variation of lifecycle costs (c/kWh) with discount rate

Discount rate (%)	7.5	9	10	11	12.5
Rate variation (%)	-25	-10	-	10	25
Cost variation (%)	-24	-9.8	-	10.1	25.9

Table H3: Variation of lifecycle costs with construction cost

Capital cost variation (%)	-25.0	-	+25.0
Output cost variation (%)	-23.6	-	23.6

TABLE H4: Variation of lifecycle costs with construction period

Construction period to first power variation (yrs)	-1	-	+1	+2
Cost variation (%)	-9.3	-	11	22

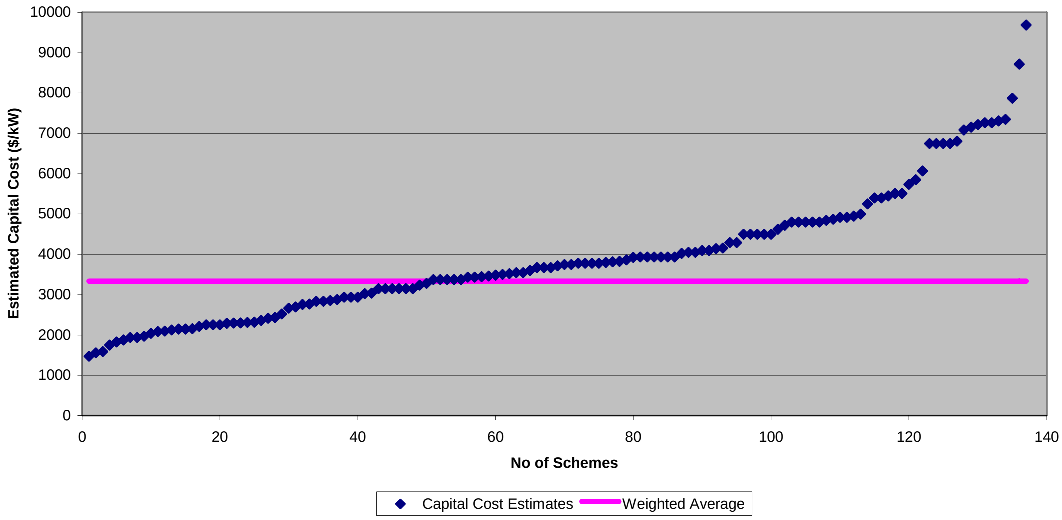
Table H5: Variation of lifecycle costs with plant factor

Plant factor variation (%)	-15	-10	-	10	15
Cost variation (%)	-17.1	-10	-	8.8	12.6

3.3 COST ESTIMATES IN THE FUTURE (2012, 2025)

Considering the maturity of hydroelectric development little variation of cost in real terms is likely in the future. There will be some exchange rate effects but because of the high local content these are not large. The current weighted average price of $3,600/kW will reduce by just over 6% to $3,340/kW in 2012.

Figure H2: 2012 Capital Cost Estimates for Potential Hydro in New Zealand



3.4 ESTIMATED OVERALL COSTS

Because of the variability of the capital costs for each scheme, no clear trend for unit costs are evident. Calculations have been undertaken for a wide range of site-specific projects and the results have been fed into the cost supply curve.

3.5 NATIONAL SUPPLY CURVE DATA

Table H6: Hydro Cost Supply Data

Supply Cost Data	c/kWh	2012/2025 MW WACC = 5%	2012/2025 MW WACC = 10%
High Confidence	2-4	700	-
	4-6	300	570
	6-8	105	130
	8-10	3	200
	10-12	-	100
	12-14	-	40
	14-15	-	65
Medium Confidence	2-4	1,070	-
	4-6	825	570
	6-8	340	500
	8-10	15	670
	10-12	30	155
	12-14	15	140
	14-15	5	205
Low Confidence	2-4	1,590	-
	4-6	1,080	575
	6-8	945	1,015
	8-10	175	875
	10-12	315	200
	12-14	50	370
	14-15	85	575

Supply Cost Data	c/kWh	2012/2025	
		GWh/y	
		WACC = 5%	WACC = 10%
High Confidence	2-4	3,830	-
	4-6	1,595	3,200
	6-8	510	630
	8-10	10	1,095
	10-12	-	500
	12-14	-	185
	14-15	-	325
Medium Confidence	2-4	5,985	-
	4-6	3,750	3,200
	6-8	1,635	2,785
	8-10	70	2,995
	10-12	145	755
	12-14	70	640
	14-15	30	990
Low Confidence	2-4	8,515	-
	4-6	5,005	3,265
	6-8	4,465	5,250
	8-10	845	3,905
	10-12	1,470	1,100
	12-14	240	1,750
	14-15	390	2,715

4. FURTHER RESEARCH AND OTHER ISSUES

Significant refinement of supply data is possible, but at considerable cost.

Cost-energy quantities are derived from engineering judgement and previously published reports. Considerable study effort would be needed to further differentiate cost of supply and energy output estimates. Individual schemes would need closer examination which raises the issue of proprietary nature of information.

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CHAPTER 2 - GEOTHERMAL

1. TECHNOLOGICAL INFORMATION

1.1 ENERGY RESOURCES

New Zealand's geothermal resource base is large, and is currently the second largest renewable energy source contributing to the national energy supply. About 6% of total electricity generation and 38% of primary renewable energy supply is associated with geothermal energy.

Geothermal energy derives from the heat contained in the earth, and therefore can be regarded as unlimited in quantity. About 80% of the heat in geothermal systems comes from radioactive decay of isotopes in minerals in the Earth's crust, and about 20% from heat associated with formation of the Earth. Localised heat sources occur in volcanic regions or tectonic regions (where active fracturing allows deep circulation of ground waters). The normal temperature gradient of about 30^0C per kilometre of depth makes it uneconomic to extract it from just anywhere. The practical aspects of harnessing it confine its development largely to zones where the Earth's crust is thin or fractured, and close to the edges of the continental plates where volcanism and earthquakes are also prevalent.

Use of geothermal energy is helped by the presence of a heat source, permeability within the rock and by the presence of water able to flush out the heat from the rock.

Resource usefulness may be affected by:

- concern over connection to nearby protected resources;
- poor public perception;
- potential effects on the surface environment in sensitive areas;
- concentrations of gas (mainly CO_2, with H_2S to a lesser extent);
- high concentrations of dissolved solids (from water-rock interaction - some of these products can have high commercial value) that may cause scaling problems; and
- presence of corrosive fluids (either from shallow condensates or possibly from magmatic sources).

Field behaviour changes with time, particularly affecting well enthalpy and gas concentrations. Production/reinjection centres may change, requiring active engineering.

There is a further geothermal resource associated with the Earth's thermal inertia. This resource is based on the fact that soil temperatures at a depth of 1m are stable relative to seasonal variations in ambient air conditions. This opens up a nationwide resource for use in conjunction with heat pumps. This resource potential is assessed to be small and is not discussed in detail in this report.

1.2 SYSTEM ELEMENTS

The capture of geothermal energy is done by containing the fluid transporting the heat. In its simplest form, for non-electricity generation purposes, this may be a channel directing the flow of water from a hot spring. For high temperatures, a drilled well with control valves and measuring instruments is required. Wellhead pressures of 80-100 bars have been measured in New Zealand.

Except where the end use is located at the wellhead, a piping system for distributing or collecting the hot water from one or more wells to one or more users must be designed to accommodate pressure, thermal expansion, and heat loss, etc. and also needs instruments and controls.

To fit the fluid to its end use often requires some form of treatment, such as:

- Entrapment of particulate impurities
- Separation of water from the steam, normally done centrifugally
- Heat exchange from the reservoir fluid to a secondary one, such as air for space heating, fresh water to avoid reservoir chemicals, or a refrigerant to improve efficiency through a binary cycle plant
- Separation of dissolved solids by settling or chemical treatment
- Degassing

If the end use is a direct heating application, there is a need for distribution, containment and perhaps storage of the heat in piping, buildings, and tanks.

For conversion into electrical energy, one of two arrangements is possible. The conventional option uses a turbo-generator set up, with all the conventional mechanical and electrical auxiliaries, possibly including condensers, cooling towers and electrical transmission. The alternative is to use binary cycle equipment where the steam or hot water heats a secondary working fluid which is then run in a closed cycle, frequently using air coolers. Hybrid systems can also be used where steam is run through a steam turbine then condensed in the binary plant.

Disposal of the cooled geothermal fluid demands careful attention due to the large flows of relatively low-grade heat typical of geothermal projects. Almost universally, reinjection of the liquid fraction is the preferred option, but this does require careful engineering to avoid cooling of the production reservoir and scaling or corrosion of the reinjection equipment. Often, unproductive wells already drilled can be used. Dispersion of gas effluents with help from cooling towers is normally acceptable.

1.3 SYSTEMS AND APPLICATIONS

Table G1 below lists a number of applications for geothermal energy, many of which are in operation or can be considered for use in New Zealand.

A concept of cascaded use is commonly suggested for maximum efficiency where waste heat from one part of the process is used for a lower temperature application. There are examples in New Zealand of this. The possibility exists for more labour intensive industries such as horticulture or aquaculture - drawing people back to the land (a strong consideration for Maori groups involved in resource development).

In terms of high temperature uses, focus has been on generation of electricity as the main development driver with cascaded process heat use below this. There is increasing realisation of the value of process steam. This could see other applications similar to the Kawerau development where process steam is the value driver and waste heat is used for electricity and other process heat applications. However, this requires an industry to be developed on a field or for geothermal heat to be piped to relatively nearby industry.

Table G1: Potential Applications of Geothermal Energy Based on Temperature

		Temp. (°C)	Main Process	
	Saturated Steam	180	Evaporation of highly concentrated solutions; Refrigeration by ammonia absorption; Digestion in paper pulp, Kraft	Conventional Power Production
	Saturated Steam	170	Heavy water via hydrogen sulphide processes; Drying of diatomaceous earth	Conventional Power Production
	Saturated Steam	160	Drying of fish meal; Drying of timber	Conventional Power Production
	Saturated Steam	150	Alumina via Bayer's process	Conventional Power Production
	Saturated Steam	140	Drying food products at high rates; Food canning	Binary Cycle & Kalina Cycle Power Production
	Saturated Steam	130	Evaporation in sugar refining; Extraction of salts by evaporation and crystallisation	Binary Cycle & Kalina Cycle Power Production
Water	Saturated Steam	120	Fresh water by distillation; Most multiple effect evaporations, concentration of saline solution	Binary Cycle & Kalina Cycle Power Production
Water	Saturated Steam	110	Drying and curing of light aggregate concrete slabs	Binary Cycle & Kalina Cycle Power Production
Water	Saturated Steam	100	Drying of organic materials, seaweeds, grass, vegetables, washing and drying of wool	Binary Cycle & Kalina Cycle Power Production
Water	Saturated Steam	90	Drying of fish stock; Intense de-icing operations	Binary Cycle & Kalina Cycle Power Production
Water		80	Space heating; Domestic hot water heating; Greenhouse space heating	Binary Cycle & Kalina Cycle Power Production
Water		70	Refrigeration (low temperature limit)	Binary Cycle & Kalina Cycle Power Production
Water		60	Animal husbandry; Manure processing; Cheese manufacturing; Greenhouse combined space and hotbed heating	
Water		50	Mushroom growing, poultry hatching; Brooding; Balneological baths	
Water		40	Soil warming	
Water		30	Swimming pools; Biodegradation; Fermentation; Warm water for mining all year round in cold climates; De-icing	
Water		20	Hatching of fish; Fish farming	

While geothermal fluid can be produced intermittently, the expense of extra wells and surface pipework for peak supply tends to cause total energy costs to be significantly higher than the alternative of coupling geothermal with a different source for peak loads only. In the case of a hot water system (such as district heating) the fluctuating demand is best met by installing storage tanks (heat accumulators). Electricity generation from geothermal energy commonly achieves long-term capacity factors exceeding 90%.

Although there are normally cost advantages in large-scale development, geothermal applications are worthwhile in small units, and are suitable for staged expansion. Many fields have exploration wells capable of production as a result of a previous Crown investigation programme. These wells allow confidence and economies in small-scale developments.

1.4 TECHNICAL STATUS

Use of geothermal heat for bathing dates from prehistoric times. The Romans used geothermal fluid for underfloor heating. Maori have used the resource for cooking, bathing and ritual purposes.

Geothermal fluids have been used for mineral extraction for centuries. A boric acid plant preceded the first generation of electricity on the Lardarello geothermal field 100 years ago.

Geothermal electricity generation technology is sometimes referred to as new, although it has been used in Italy since the turn of the century and secondly, in New Zealand since the 1950s.

New Zealand scientists and engineers developed the basic techniques of investigating and utilising hot water resources, and are still regarded amongst the leaders in both hot water and steam dominated reservoir technology around the world. They have had extensive experience in field developments in many countries. The Geothermal Institute at the University of Auckland is a world-leading training organisation.

In general, the energy conversion plants used have well proven specifications and can provide very reliable service as the 44-year-old equipment at Wairakei demonstrates. The more recent binary cycle plant now has a reasonable history with Kawerau plant having operated for more than 10 years.

New Zealand can provide leadership in the area of process heat supply, helped by the juxtaposition of major forestry resources with geothermal resources.

It is in the resource development sector that there remain most opportunities for local efforts to make noteworthy advances in geothermal technology. Aspects warranting continuing attention include:

- Application of advanced geophysical techniques to better identify field boundaries and most productive zones e.g. active seismic and passive microseismic techniques.
- More refined reservoir assessment and modelling during operation. This requires greater attention to input data.
- Economic extraction of dissolved minerals.
- Inhibiting silica or calcite deposition.
- Optimised steamfield and station design.
- Application of better drilling techniques to deal with lost circulation and to maximise production.
- Understanding and mitigating environmental effects.
- Reduction of perception of environmental impacts.
- Reduction of perceived financial risk.

New Zealand has yet to take up ground source heat pumps to any significant extent, though these are used extensively in the United States and Europe.

To date New Zealand has not used gas abatement technology, though its use is common overseas, and it may permit the use of higher-gas resources while achieving an acceptable environmental impact.

Several other methods of extracting geothermal heat are being researched overseas. These include:

(a) The hot dry rock (HDR) technique where a couplet of wells is drilled to great depth in relatively impermeable rock at elevated temperatures. Artificial permeability is created by hydraulic fracturing between the wells then recirculation of fluids between the wells is commenced to flush out heat from the rock matrix.

(b) Drilling directly to the molten magma for access to higher temperatures.

The very high costs involved in these projects prevent any substantial New Zealand uptake. While there are still substantial undeveloped high temperature geothermal fields, these more exotic forms of geothermal exploitation are unlikely to be taken up and are not considered in this review.

1.5 APPLICATION LIMITS AND SYNERGIES

Geothermal fields are treated as being of finite size, with assessment largely based on depth tested by drilling (plus a radius of influence). Energy extraction rates are set to sustainable levels based on the assessed resources. The energy resource beneath drilled depths is extremely large. As development disturbs the geothermal field through pressure drawdown, the field can be renewed by additional recharge of fluid from this deeper resource.

Electricity produced from geothermal energy can be utilised at national, local, and industry levels. Where the resource and disposal aspects have been solved, the direct use of medium and low temperature geothermal fluids in industrial and domestic applications has proved viable.

The scale of projects in New Zealand is usually resource consent limited, rather than limited by the resource itself or technology. Given that there are economies of scale, then restricted consents (well below the perceived field capacity) impose cost disadvantages on geothermal developments. Both consents and funding arrangements can impose a staged development on potential projects. Most of the existing developments can be regarded as the first stage of a larger project.

Suitable fields may be developed for the generation of electricity, but because of potential and existing resource consent constraints there is likely to be greater opportunities for use of the resource in direct heat applications. This may involve both the reject heat from power plants, and high to low temperature fluids extracted as such from the subsurface reservoirs. Potentially greater rewards are possible for process heat supply where industry locates close to available reservoirs. The Kawerau development is a good example.

There are technical limits on the amount of heat that can be extracted from geothermal fluid due to the risk of scaling (deposition). Silica content has been a particular limiter. For example, in a certain field the limitation imposed by silica saturation in the waste fluid may limit the rejection temperature to greater than 90^{o}C. With scale reduction it would otherwise be feasible to extract further energy for a direct heat application. Consequently research is being carried out into methods to reduce this scaling risk, and thus increase the use of energy before disposal.

A cost balance may be necessary to weigh the value of an active ongoing drilling programme (to counter scaling or other causes of well rundown) against the perceived benefits of electricity or heat sale. This may cause developers to limit production below that of plant capacity.

Until recently, it was thought that geothermal heat could not be transported significant distances. It is now recognised that distances can approach 20 km for major process loads enabling a range of fields to be used to supply heat to local centres.

There is a possibility of using geothermal heat in the wood processing industry because of the proximity of major forestry resources to the fields.

Some synergies may exist between geothermal resources and other energy supplies, e.g. wind, biomass, hydro, where fuel shortage risks can be managed by integration.

Synergies may also exist with biomass liquid fuel production. Heat from the Reporoa field could be used to assist production of ethanol from whey at the dairy factory there.

Advanced research is now underway on synergies between geothermal fluids and landfills to enhance methane production (Heveldt 1999).

1.6 CRITICAL FACTORS

Resources are site specific, and so must be developed and used on the field or within a restricted radius. High temperature resources are mainly in the Taupo Volcanic Zone and are generally located south of the electricity transmission constraint in the Whakamaru area, restricting immediate usefulness.

There are many fields that are likely to be attractive sustainable developments. However a prerequisite for development is resource consents. Consenting for geothermal developments tends to be in an unsupportive environment. Regional councils have taken a protective view of these resources, as a default position. Two of the successful resource consent applications for geothermal projects in recent years have been allowed to take 25% of the fluid applied for at Poihipi and Ngawha, and 40% (of a reduced application) at Tauhara (PA Consultants 2001). The councils' focus is on local soil, water, flora/fauna and social aspects while global and national issues associated with greenhouse gas emissions are largely outside their consideration. A National Policy Statement on the geothermal energy is needed to provide a new framework for the councils to work in.

A critical aspect of geothermal development is the relatively high cost of proving the viability of a prospect. The cost will be minimised by sound application of scientific exploration techniques and modelling, leading to better well siting and therefore the need for fewer wells to be drilled before committing (or abandoning) a project. However, the unsupportive consenting environment means few developers will consider expenditure for consents and field investigation, if there is not sufficiently encouraging information on the resource available from past investigation including successful wells.

Also, the perceived risk will be reduced as developers gain confidence in the predictive capability of competent reservoir scientists and engineers. Technologists for their part must work up development packages for financiers that include, from the outset, details of investigation, construction phases, and specification of regular performance check points at which decisions can be made to proceed or abandon a prospect. Phased development has become a standard approach.

For direct use for industrial heat, confidence in assured long term supply must be coupled with the economic siting of the plant near to a suitable field. Economic use of the cascading type, multipurpose heat arrangement, mentioned earlier, may be dependent on favourable fluid transport costs or proximity to markets for each product produced.

For any development type, developers will have to try to select an optimal project taking advantage of economies of scale and niche opportunities presented by existing wells.

1.7 ENVIRONMENTAL ISSUES

A conservative precautionary environmental consent process is applied by Regional Councils to geothermal development. This has removed a high proportion of fields from development consideration and tended to restrict initial developments to a small portion of their potential. This has been partly affected by public perceptions (whether accurate or not) that there could be significant local geomorphological change including subsidence and hydrothermal eruption.

The regulatory process itself leads to long delays and risks which impose a significant up-front cost on the projects, reducing their financial viability. A new geothermal project of 100MW would almost certainly be involved in an appeal to the Environment Court, adding at least two years and considerable cost to the project (PA Consultants 2001).

Several fields have recently received Environment Waikato's "Protected 2" designation in the Proposed Waikato Regional Plan. Policy 3 of the proposed plan requires that limited developments "avoid any adverse effects on volumetric flow rate and temperature of the heat source". As geothermal systems are not closed, any development will impact on flows and temperatures. Thus there is an effective ban on development of fields under this designation. Contact Energy has objected to this designation and associated policies as Environment Waikato has not followed the required process for revision of the Plan, and the changes are not in obvious response to any previous submissions. These fields have previously been "unclassified" and open to development given suitable justification. This position could be restored if Contact Energy's objection is successful.

Reinjection of waste fluids, while adding risk and cost to reservoir management, has eliminated the concerns associated with surface disposal. This is now a standard feature of new geothermal developments.

Another issue is the extent to which natural thermal features (e.g. geysers) may be affected. (It is worth noting that geothermal development can also create features of tourist value.) Part of the problem facing regulators is the poor ability to predict just what might happen to natural thermal features under various development scenarios. The complexity and fluctuations of nature itself mean that improvements in prediction will probably be slow. One consequence is that fields with unique features of scientific, tourist and cultural value have been protected from development. Others, like Rotorua, have conservative restrictions placed on the areas and flow rates permitted for fluid extraction.

A cultural issue is the strong interest by Maori in the resource which is viewed as a taonga. This interest is not necessarily shown as an anti-development stance. Maori Trusts have been active participants in four of the recent geothermal power station developments. An important part of the Trusts' planning involves consideration of downstream uses that may draw people back to the land.

To avoid problems with competing interests on geothermal fields, the Waikato Regional Council (Environment Waikato) has a "single tapper" policy which essentially gives field control to current consent holders or the first serious applicant.

The following table assesses New Zealand field emission rates, averaging 100g of CO_2/kWh. While significant, this is still much less than fossil fuel technologies. In some cases the CO_2 would have been emitted naturally.

Table G2: New Zealand Geothermal Field Emission Rates[1]

	MW	GWh	Steam t/h	Gas %	CO_2 kt/year	CO_2 g/kWh
Ohaaki	40	343	348	2.86	86	249
Wairakei	161	1,384	1,377	0.59	44	32
Poihipi Road	25	212	200	0.43	7	35
Rotokawa	28	210	144	2.00	22	105
Mokai	61	430	308	1.30	28`	66
Kawerau	32 (equiv.)	262	257	2.82	59	226
Ngawha	9	77	428 (total fluid)	1.32	46	597
Average	**51**	**417**	**437**	**1.62**	**42**	**100**
Coal Best Practice						955
Oil Best Practice						818
CCGT						430

1. Source: White 2001

Resources are altered by exploitation but sustainable developments are selected for economic reasons. There is debate over the “renewability” of the resource.

2. NEW ZEALAND RESOURCE INFORMATION

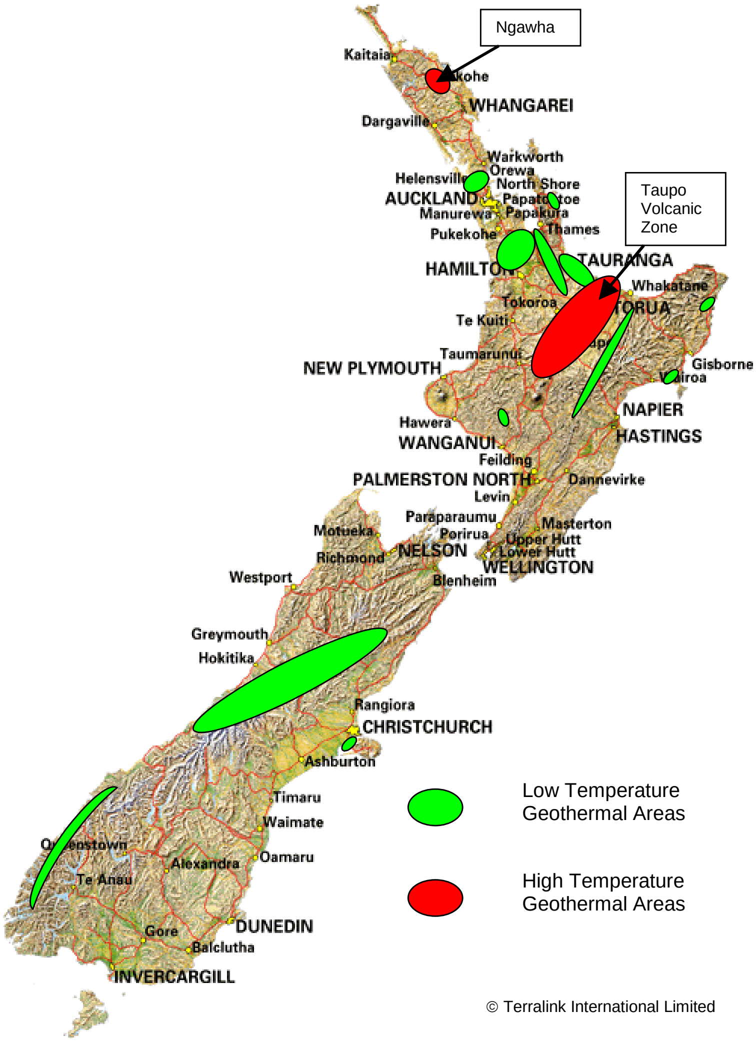
2.1 INFORMATION SOURCES

This report draws on the 1993 Ministry of Commerce report. A range of other references is given at the end of this resource section. Resource assessments are based on a 2001 report by Lawless and Lovelock, representing a good collation of publicly available information. Utilisation for both electricity and heat is based on a 2000 report by Thain and Dunstall published at an international geothermal forum. The view on uptake and development costs is based on the experience of the reviewer.

2.2 THE LOCATION OF RESOURCES

The following Figure G1 shows location of geothermal resources. The map shows broad areas rather than specific resources. The focus of research until recently has been on the high temperature resources.

Figure G1: Location of Geothermal Resources in New Zealand



2.3 THE QUANTITY OF THE RESOURCE

A DSIR report (Mongillo and Clelland, 1984) summarising the known thermal areas in New Zealand leads to the following table:

Table G3: Numbers of Thermal Areas

Region	Range of Maximum Spring/Well Temperatures (^oC)			
	30-69	**70-140**	**140-220**	**>220**
Northern	8	1	0	1
Hauraki	16	1	1	0
Rotorua – Taupo	5	9	6	14
Other North Island	4	1	0	0
South Island	19	2	0	0
New Zealand	**52**	**14**	**7**	**15**

In addition to the above areas, a further 41 were identified as being either below 30°C or unmeasured but warm. Also, there was a mix between spring temperatures and subsurface observations measured in wells.

There are still no comprehensive assessments of low temperature resources, although these are qualitatively discussed in Cave et al 1993. A recent assessment of high temperature fields (Lawless and Lovelock 2001) is summarised in the table below. This is based on simple stored heat calculation modified by a Monte Carlo analysis.

2.4 VARIABILITY OF SUPPLY

Geothermal resources generally require active engineering over the life of the project. The fields at Wairakei, Kawerau and Broadlands/Ohaaki have seen marked changes over their commercial lives. Well characteristics have changed in terms of enthalpy and flow rates under production. This has forced changes in fluid collection and treatment systems, with new wells being brought on line to maximise benefits. In recent years, Ohaaki has been allowed to run down in output partly due to a balance between the cost of makeup wells and the value of the electricity on the national market, rather than insurmountable technical obstacles.

Table G4: Quantity of High Temperature Resources (based on Lawless and Lovelock 2001)

Field	Resource Area km^2			Depth to Reservoir m	Resource Thickness m			Void Space %			MeanTemperature[1] °C			Generating Capacity[2] MWe		
	min	mode	max	m	min	mode	max	min	mode	max	min	mode	max	10th	median	90th
Fields Available for Further Development (High/Medium Confidence Resources)																
Horohoro	1	1.5	5	500	1,800	2,000	2,500	8	10	12	190	200	230	4	9	18
Kawerau	25	35	40	400	1,500	2,100	2,500	6	8	10	260	270	280	350	450	570
Mokai	5	6	18	700	1,250	1,800	2,300	8	10	12	260	280	295	100	155	250
Ngawha	10	18	25	400	1,800	2,100	2,500	3	4	6	220	240	260	50	75	120
Ohaaki	5	11	12	400	1,800	2,100	2,500	6	8	10	260	275	280	100	135	175
Rotokawa	16	18	20	500	1,700	2,000	2,500	6	10	12	260	280	295	250	330	420
Rotoma	4	5	6	500	1,700	2000	2,500	6	8	10	220	240	245	28	35	46
Tauhara	7	15	24	500	1,700	2,000	2,500	10	12	15	250	260	270	190	280	390
Tikitere-Taheke[3]	15	35	40	500	1,000	1,800	2,200	8	10	12	220	240	260	160	240	350
Wairakei	15	25	30	350	2,000	2,150	2,650	10	15	20	250	255	265	450	600	850
Subtotals														**1,680**	**2,310**	**3,190**
Fields with an Interim Protected Status (Low Confidence Resources)[4]																
Mangakino	8	9.5	17	800	1,500	1,700	2,200	8	10	12	220	230	250	65	85	120
Ngatamariki	10	14	16	400	1,800	2,100	2,500	6	10	12	250	260	270	140	190	240
Reporoa	8	10	15	700	1,000	1,500	2,000	8	10	12	220	230	240	50	65	90
Tokaanu	15	20	30	800	1,500	1,700	2,200	4	8	12	250	260	270	150	220	310
Subtotals														**400**	**560**	**760**
Fields with a Protected Status (Unavailable Resources)																
Atiamuri	3	4	5	800	1,500	1,700	2,200	8	10	12	190	220	230	10	18	26
Ketetahi[5]	10	12	20	800	1500	1,700	2,200	4	8	12	230	245	260	70	105	160
Orakei-Korako	8	9.5	12	400	1,800	2,100	2,500	8	10	12	250	260	270	125	150	180
Rotorua[6]	2	4	8	500	1,500	1,800	2,000	8	10	15	220	240	250	25	35	55
Te Kopia[7]	6	10	12	500	1,700	2,000	2,500	8	10	12	230	240	250	70	95	120
Waimangu	9	12	30	400	1,800	2,100	2,500	8	10	15	250	260	270	180	280	420
Waiotapu[8]	25	35	50	500	1,200	2,000	2,500	8	10	12	260	275	280	440	590	800
Subtotals														920	1,275	1,760
Means and Totals:									**9.6**			**250**		**3,000**	**4,100**	**5,700**

Notes:1. Mean temperature through accessible reservoir thickness and area, not maximum, and for developed fields, before exploitation. 2. Three values 10th, 50th (mode) and 90th percentiles. 3. Excludes Lake Rotoiti. 4. These are fields designated "Protected 2" under the Proposed Waikato Regional Plan. This new protected designation has been objected to in a submission by Contact Energy Ltd. 5. Ketetahi has also been given a "Protected 2" designation under the Proposed Waikato Regional Plan. However, because it is surrounded by a National Park, development should not occur. 6. Excludes Lake Rotorua. Limited use of the Rotorua field is permitted and occurs, but preservation of surface features is of prime importance so cannot be considered for large-scale development. 7.Te Kopia is also a "Protected 2" field but is unlikely to be developed because of proximity to fully protected fields. 8. Includes Waikite

2.5 CURRENT UTILISATION OF RESOURCES

The major use of New Zealand geothermal resources is for electricity generation. Several power stations have been built in recent years, largely with private funding.

Current power stations are summarised in the following table (Thain & Dunstall, 2000). Since Ohaaki was constructed, all stations have either used second-hand plant or have been based around an Ormat binary cycle design. There have been no additions to capacity since Mokai was commissioned in 1999.

Table G5: Utilisation of Geothermal Energy for Electric Power Generation as at 31 December 1999

Locality	Power Plant Name	Year Comm-issioned	No. of Units	Status	Type of Unit	Unit Rating MWe	Total Installed Capacity MWe	Annual Energy Produced 1999 GWh/yr	Total Under Constn or Planned MWe
Taupo	Wairakei	1958-63 1996	10 3	OP Planned	2 IP-BP 4 LP - C 3 IP - C 1 LP -BP Binary	2 x 11.2 4 x 11.2 3 x 30 1 x 5 3 x 5	162	1,290	 15
Taupo	Poihipi Rd[1]	1996	1	OP	1 IP C	1 x 55	55	225	
Broadlands/ Reporoa	Ohaaki[2]	1989	4	OP	2 HP -BP 2 IP - C	2 x 11.2 2 x 46	114	350	
Kawerau	Tasman P&P Co.[3]	1966	1	OP	1 BP	1 x 10	10	60	
Kawerau	Kawerau Binary	1990	3	OP	Binary	2 x 1.2 1 x 3.5	6	40	
Taupo	Rotokawa	1997	4	OP	Hybrid BP/binary	1 x 12 3 x 4.5	25	200	
Northland	Ngawha	1998	2	OP	Binary	2 x 4.5	9	73	
Taupo	Mokai	1999	7	OP	Hybrid BP/binary	1 x 25 6 x 5	55	30	
Total			**35**				**436**	**2,268**	**15**

1. Poihipi Rd (formerly McLachlan) station is restricted to about half its installed capacity by resource consent restrictions, currently drawing from the apparent margins of the Wairakei field.
2. Ohaaki was derated to 104 MW due to condenser problems in 1996. Effectively it is down to 1 HP and 2 IP units.
3. Kawerau turbine was derated to 8MW

BP = Back Pressure C = Condensing OP = Operational

The following two tables (Thain and Dunstall, 2000) outline some of the existing direct use applications of geothermal energy. The list is partial. Other developments include many hot springs developed for bathing scattered through both the North and the South Islands. Extensive use is made of geothermal heat in Taupo and Rotorua for domestic heating. This is also true for Parakai and Waiwera (north of Auckland), at Tauranga (potable water between 30 and 45^{o}C), Tokaanu-Waihi (by Turangi) and Hanmer Springs in the South Island.

Table G6: Utilisation of Geothermal Energy for Direct Heat as at 31 December 1999

Locality	Type[1]	Maximum Utilisation					Capacity (MWt)	Annual Utilisation		
		Flow Rate (kg/s)	Temperature (°C)		Enthalpy[2] (kJ/kg)			Avg. Flow (kg/s)	Energy (TJ/yr)	Capacity Factor
			Inlet	Outlet	Inlet	Outlet				
Kawerau	I	89			2,780	420	210	74	5,500	0.8
Kawerau	A	6.8			2,780	420	16	3.4	253	0.5
Kawerau	G				2,780	420	>0.08	0.034	2.5	
Broadlands Reporoa	A	42	142	90			9.1			<0.5
Broadlands Reporoa	A	19	142	90			4.1			<0.5
Wairakei	F	89	130	80			18.6	55	363	0.6
Taupo	G				2,760	420	0.06			
Rotorua	H	110			600	400	>22		694	
Total		**335.8**					**280**	**132**	**6,813**	

Notes:
1. A = Agricultural drying (grain, fruit, vegetables)
   F = Fish and animal farming
   G = Greenhouse and soil heating
   H = Space heating & district heating (other than heat pumps)
   I = Industrial process heat
2. Enthalpy information is given only if there is steam or two-phase flow

Table G7: Summary Table of Geothermal Direct Heat Uses as at 31 December 1999

Use	Installed Capacity[1] (MWt)	Annual Energy Use[2] TJ/y	Capacity Factor[3]
Space heating[1]	>22	>700	-
Fish and Animal Farming	19	363	0.6
Agricultural Drying[2]	29	>253	-
Industrial Process Heat[3]	210	5,500	0.8
Bathing and Swimming[4]	28	265	0.3 (est.)
Subtotal	308	7,081	-
Geothermal Heat Pumps	-	-	-
Total	**308**	**7,081**	**-**

Notes:
1. Includes district heating
2. Includes drying or dehydration of grains, fruits and vegetables
3. Excludes agricultural drying and dehydration
4. Includes balneology

2.6 INFRASTRUCTURE OBSTACLES

All available high temperature fields are readily accessible by road, and in some cases by rail.

The Central North Island fields are generally located south of Whakamaru. There are electricity transmission constraints in this area that must be addressed. However, the comparative lack of renewable energy resources north of Whakamaru, coupled with the large demand centred on Auckland, should force resolution of this constraint issue for economic and political reasons.

2.7 VIEW ON UPTAKE

Geothermal energy is generally constrained by location.

The total field capacity indicated in the following section is based on the estimates in Table G4, with previous and ongoing utilisation netted off.

South Island

South Island resources are all of relatively low temperature. Many of the springs are in remote areas and will have no commercial value. Some resources, such as those at Hanmer have been developed for bathing with further development unlikely.

Higher temperatures (>60^{o}C) are found at Maruia and inland from Hokitika. The Hokitika resource might have very limited tourism value. Additional resource use at Maruia will face a strong environmental lobby.

There are low temperature resources across Banks Peninsula and at Oamaru that could see some use for enhanced geothermally-based heat pump systems. This use near Christchurch will be induced by efforts to reduce emissions in the area.

North Island High Temperature Resources

Fields surrounded by a National Park or with a “protected” category have been excluded from this review. These fields include Ketetahi, Atiamuri, Orakei-Korako, Waimangu, and Waiotapu.

Horohoro has been given a development designation by Environment Waikato. Exploration wells were drilled in the area but the focus of interest has been shifted. The latest published information indicates a limited resource of uncertain characteristics. It is within 20 km of Rotorua so heat could be piped to the city or to forestry and other interests along the way. A small development is possible.

The Kawerau field is under Environment Bay of Plenty jurisdiction. It has been the site of the world’s largest industrial geothermal heat supply dating back to the 1950’s (contemporary with Wairakei’s development), with subsequent development, including binary cycle generation. The field could support an additional 260 to 480 MW of development over and above current/ongoing usage. A potential rationalisation of energy usage at the Kawerau field which could be commissioned by 2006 could provide 500 MWth of heating in addition to 50 MWe of generation (PA Consultants 2001). In the past, there had been some concern about differential settlement in the vicinity of the Kawerau mills. This does not appear to have been a problem. There are wells in the area, which the Crown is viewing as potential compensation for Waitangi claims. Resolution of claims and allocation of wells will allow commercial development to proceed with certainty. Major expansion will require extensive investigation drilling to the South. Staged development is likely (with 50MWe stages possible). Kawerau township is located over the field so that hot water could potentially be piped for domestic and commercial heating.

Mokai can be expanded further by 40 to 190 MW, but some effort will have to be directed to proving additional resource if further stages are wanted. This will include monitoring field performance, modelling future performance and undertaking additional drilling to firm up on the resource size and boundaries. The Tuaropaki

Trust has expressed a strong interest in utilising heat commercially. Some small-scale heat opportunities are likely but there are no known large-scale opportunities.

Ngawha can also be expanded by 40 to 110 MW (although estimates given by Lawless and Lovelock are considerably lower than earlier estimates). There are numerous existing wells to base expansion on, and local energy resource shortages may help drive the consent approval process. A factor counting against Ngawha is the high gas content (a Ngawha station will produce nearly 50% more CO_2 than an equivalent-sized combined cycle power station). The very small size of the initial development may limit its usefulness in making projections of resource response to a much larger development, so that further stages may be required. The present resource consents are based on criteria of causing no measurable effects on the surface thermal features. If this continues to be the case, any further development may be very limited.

Contact Energy manages the Ohaaki field. While Table G4 indicates some additional resource may exist, experience indicates the field is stressed by the existing development. There is a possibility of say 2 MW of binary cycle plant to make greater use of the hot water before reinjection, but that would increase difficulties associated with field and plant management. No additional generation is expected.

Rotokawa can experience major expansion by 220 to 390 MW. As for Ngawha, the small initial stage may limit the usefulness of monitoring data for extrapolation to a large scale development and intermediate stages may be required. The Environment Waikato “single tapper” policy will mean that some form of partnership will be required with the Tauhara North No. 2 Trust at Rotokawa. This will also apply to the owners of adjacent Maori land who have also expressed an interest in development. Mighty River Power has recently obtained a 50% share in the field with Tauhara North No. 2 Trust and wholly owns the existing station. Mighty River has also purchased interests that Fletchers had in the resource both at Rotokawa and Ngatamariki. Rotokawa is of such a high temperature that it could supply major industrial heat loads at Taupo, possibly for timber drying. There are very few landowners between the field and Taupo timber processing industries although pipes would have to cross the Tauhara geothermal field. Temperature and distance may not preclude a competitive steam supply.

A 50 MW proposal existed for the development of Rotoma by Trust Power. Trust Power interest has waned but a limited development may be possible, say 10 MW initially but ultimately with 30 to 50 MW.

Consents for a 15 MW Contact Energy development at Tauhara exist (strictly for a 20kt per day fluid supply). The consents allow for an additional 50 MWth of heat to be provided to local industry. This is due to come on stream in 2004 (PA Consultants 2001). This development is a small fraction of the total resource but was limited by objections from Taupo residents. Successful operation of the 15 MW plant may allow a step up in size by a 50 MW step similar to Contact Energy’s earlier concept for field development. Given that the Wairakei and Tauhara fields are linked then further development is likely to be based on optimum development of the total block. Given the strong objection to development, the ultimate capacity of 190 to 390 MW is not realistic and a 70 MW (15+5+50) limit is assumed.

Trust Power in joint venture with Rauhine-Kuharua proposed a 10 MW joint venture development of Taheke. Despite the large field size (160 to 350 MW), only limited development is expected because of the strong local interest in maintaining the tourism value of the Tikitere (Hells Gate) area. 10 MW is a reasonable assumption, probably with cascade use of waste heat.

Contact Energy owns/manages the existing Wairakei steamfield and stations (Wairakei and Poihipi). It should be emphasised that Contact is cautious about considering any expansion of the Wairakei facilities. The field may be able to support another 40 to 430 MW above current levels, which despite the age of the plant are at close to record generation levels. The field has taken active engineering to bring these levels about. The field itself has experienced cooling at its margins and field wide drawdown. However, these aspects are manageable, particularly now that the resource has a "single tapper". Deeper drilling for makeup wells could prove increased potential and give encouragement for expansion. New plant may be installed to replace existing plant which is now 44 years old. In addition, a 15 MW binary cycle plant has received approval and can progress when the electricity price rises to justify the investment. If steam is supplied from the Te Mihi area of the field, then it may be possible to double the output of the Poihipi Rd station (limited by consents for take from the margins of the field) for little more than the cost of consents and a short pipe. Some of these benefits were recognised in the price paid to the original owners when Contact Energy bought Poihipi. A third Wairakei power station has now been suggested by the original proponent of Poihipi. This proposal will have to address the "single tapper" policy, and may not proceed because of this.

Most fields covered by the Proposed Waikato Regional Plan "Protected 2" designation are regarded as having development potential. However any access to these will require the success of the Contact Energy objection to the changes. These fields had all been unclassified prior to the latest draft plan, with the possibility of development. For this report, these resources are assumed available at the lowest confidence level.

Mangakino has a potential of 65 to 120 MW and has been tested by the drilling of one productive well. The field is largely on Carter Holt Harvey land and is suited to both generation of electricity and transportation of heat to the nearby facility at Kinleith. No firm proposals are known.

Ngatamariki is a field with high temperatures, some good wells and a 140 to 240 MW potential. It is too removed from load centres to be able to supply process heat but would be a good prospect for electricity generation.

An existing dairy factory is located on the Reporoa field, partly located to take advantage of the geothermal resource. If the field is developed there is potential to substitute geothermal energy for natural gas for whey-alcohol distillation, thus potentially assisting with biomass-based liquid fuels production (PA Consultants 2001). Reporoa is otherwise remote from loads so is not expected to have other heat applications. Trust Power at one stage applied for resource consents for exploration, but these were declined on the grounds that there might be a connection to the protected Waiotapu field, despite evidence to the contrary. The field has a 50 to 90 MW potential. New wells would be required.

Tokaanu is a field with good development prospects based on scientific survey, the strong level of interest in geothermal development by the Ngati Tuwharetoa tribe, existing domestic use, and juxtaposition with a maturing forestry resource owned by Tuwharetoa interests. The field has a 150 to 310 MW potential. A field development similar to Mokai would be conceivable. There would be considerable interest in cascade use of heat.

Ketetahi also has a “Protected 2” designation. Surface features are in an area surrounded by, but excluded from a National Park. However, any export of electricity or heat would require facilities to be constructed in the National Park. Consequently no development is assumed.

Te Kopia also has a “Protected 2” designation but is unlikely to be developed. The field lies along the Paeroa Fault between the protected fields of Orakei-Korako (SW) and Waikite (NE). Developers will be obliged to prove separation from the protected fields. No proposals have been suggested and no development is assumed.

Limited development is occurring at Rotorua in terms of heat use. Expansion is not expected.

An uptake scenario is summarised in the following table. This largely draws on Table G4, but nets off past exploitation and existing facilities. Definitions of confidence levels are given in the beginning of this report. Because resource bases are independent of year, the low confidence estimates are identical for the years 2012 and 2025. The high and medium confidence estimates also take into account the consent issues likely to restrict development and reflect the staging likely for some developments. The medium confidence assessment represents a more liberal consenting environment.

Table G8: Additional Utilisation over the Present Level

	Year 2012						Year 2025					
	High		Medium		Low		High		Medium		Low	
	MWe	GWh	MWe	GWh	MWe	GWh	MWe	GWh	MWe	GWh	MWe	GWh
Horohoro	0	0	9	70	18	140	0	0	9	70	18	140
Kawerau	100[1]	790	150	1,180	477	3,760	257	2,020	357	2,810	477	3,760
Mokai	42	330	75	590	192	1,510	42	330	97	770	192	1,510
Ngawha	20	160	40	320	109	860	20	160	64	500	109	860
Ohaaki	0	0	0	0	0	0	0	0	0	0	0	0
Rotokawa	50	390	100	790	393	3,100	223	1,760	303	2,390	393	3,100
Rotoma	10	80	20	160	46	360	28	220	35	280	46	360
Tauhara	20[1]	160	70	550	70	550	70	550	70	550	70	550
Tikitere-Taheke	10	80	10	80	10	80	10	80	10	80	10	80
Wairakei	40	320	90	710	432	3,400	40	320	182	1,430	432	3,400
Mangakino	-	-	-	-	120	950	-	-	-	-	120	950
Ngatamariki	-	-	-	-	240	1,890	-	-	-	-	240	1,890
Reporoa	-	-	-	-	90	710	-	-	-	-	90	710
Tokaanu	-	-	-	-	310	2,440	-	-	-	-	310	2,440
	292	**2,310**	**564**	**4,450**	**2,507**	**19,750**	**690**	**5,440**	**1,127**	**8,880**	**2,507**	**19,750**

1. The assessments for Kawerau and Tauhara include the equivalent electrical capacity of the heat load.

Note that this table indicates up to 300 MW of new generation by 2012. The New Zealand Geothermal Association (NZGA) has made a submission (December 2001) on the National Energy Efficiency and Conservation Strategy where it states that an estimate in the range of 200 to 250 MWe is a more likely figure from the perspective of consenting and staged development (NZGA 2001).

North Island Low Temperature Resources

Numerous springs have been identified through the North Island. As for the South Island, many of these are isolated so have no potential for heating on a significant scale. Large resources such as that at Naike likewise have potential severely restricted by low energy land use in the vicinity.

Commercial exploitation is taking place at Parakai and Waiwera immediately north of Auckland, but these fields are developed to their limit (Cave et al 1993).

A warm water resource exists at Whitford south of Auckland. This is a relatively shallow resource, as yet undeveloped. Water could be used for domestic heating as housing is developed in the area, or may be able to assist biodegradation at a landfill being developed by Waste Management. A previous attempt to obtain resource consents for development for bathing was unsuccessful.

The Tauranga-Maketu Warmwater Field provides a major resource in the vicinity of fast growing Tauranga. Over 200 wells have been drilled in the area between 60 and 900m deep (typically 200-450m) tapping potable water in the 30 to 45% range. There are 194 known users for heating pools, glasshouses, space heating or irrigation. The resource has been observed to respond to climatic events but appears under-utilised, with the Bay of Plenty Regional Council continuing to issue new permits for developments. Use is expected to grow.

Rotorua and Tauhara resources were discussed in the previous section. The Rotorua resource is near its limit but more efficient use can be made of the resource.

Ground Source Heat Pumps

Prorating the uptake of ground source heat pumps based on United States' statistics (Rafferty, 2001) implies installation in 100 to 500 New Zealand homes per year. This is below the significance level of this report.

3. ENERGY SUPPLY COSTS

3.1 CAPITAL AND OPERATING COSTS

The 1993 MOC report focussed on electricity production. Modular power stations of a size around 55 MWe based on condensing sets were viewed as a standard development at the time. Similarly, binary cycle plant was commercially available and had potential to make further use of the separated water, or low temperature resources.

There are economies of scale for geothermal developments. A greenfield 25 MW station/steamfield currently has a specific cost of $3,200/kW while a 50 MW station/steamfield currently has a specific cost of $3,000/kW (PA Consultants 2001). However, a feature of the New Zealand's high temperature fields is that many have been proven by a Crown drilling programme. As such many can be developed with both higher confidence and reduced cost. Through negotiated purchase, these wells can be worth several million dollars to a project.

A binary cycle plant retrofitted to a field already developed by condensing sets (so not having to bear the costs of steamfield development) currently has a specific capital cost of around $3,200/kW. Binary plant does come in modules of limited size so there are no economies of scale for plant greater than 2 MW.

Of the recent New Zealand geothermal developments, two have been hybrid steam turbine-binary cycle developments. These have been utilised on the highest temperature resources. The binary plant substitutes for the condenser in a conventional plant, with one or two supplementary units to handle the water fraction of well discharge. As for condensing plant, existing wells help offset economies of scale. However for greenfield sites, specific capital cost including steamfield are equal with the condensing set costs.

As a broad rule, steamfield costs make up about one third of the total capital costs of a power development. New Zealand steamfield costs have been less than those in the United States, largely because of the relative cost of well drilling.

If lower temperature resources are to be developed for power, eventually the best technology for this is binary cycle plant. Full steamfield costs will have to be borne by the plant. These will be field specific but could currently add between $600 and $2,000/kW to the binary cycle plant cost.

O&M does appear to be a function of plant size, with a similar sized team of people needed for a 10 MW plant as for a 30 MW plant. O&M costs are dominated by the cost of makeup well drilling.

As an approximation:

- for station size >50 MW O&M = $93/kW/year
- for station size <50 MW O&M = $(177-3.66P + 0.04$P^2$)/kW/year
- where P = station size (MW)

The costs for heat plant have not been developed comprehensively and are site specific. Systems for home or neighbourhood heating exist in places like Tokaanu, Taupo, Rotorua, Tauranga and north of Auckland.

Approximate costs for industrial heat supply have been published (White et al, 1995). Options include direct supply of geothermal steam, and the supply of clean steam via a heat exchanger. The clean steam option can add a 15-20% premium to the delivered steam cost. The following table indicates approximate costs.

Table G9: Approximate costs for direct geothermal heat supply from a dedicated field

Steam Flow, F (t/h)	Capital Cost, C ($M)	Operations and Maintenance Cost
0-12.5	C=9.3+0.035F	5.5% of capital cost per year
12.5-37.5	C=7.4+0.19F	
>37.5	C=5.1+0.25F	

3.2 SENSITIVITY

The costs developed are rough, but consistent with past practice. A major unknown is the likely success of wells, with wells in close proximity potentially having markedly different flow rates. Steamfield costs can conceivably vary by ±30% while station costs would demonstrate normal variability.

3.3 COST ESTIMATES IN THE FUTURE (2012, 2025)

As time progresses there will be competing forces. More of the already drilled fields will be taken up for development. In the absence of existing wells, greater investment will be required in new wells. Additional to this, well drilling costs could rise as the international companies that now own and operate the drilling rigs look to international markets and market pricing.

Counteracting this will be minor technology improvements. A real cost decrease has been evident in large condensing plant. Binary cycle plant is now proliferating. There may be a trend for improved binary plant performance through use of mixed boiling point fluids as in the Kalina cycle.

In the absence of better information it will be assumed that the only net change in costs will be due to the effects of exchange rate.

An exchange rate of NZ$1=US$0.50 will mean that a 25 MW station/steamfield will have a specific cost of $2,825/kW while a 50 MW station/steamfield will have a specific cost of $2,650/kW. Similarly, binary plant will reduce to $2,825/kW, with its associated steamfield adding between $525 and $1,750/kW.

As an approximation:

- for station size >50 MW O&M = $83/kW/year
- for station size <50 MW O&M = $(157 - 3.25P + 0.035P^2)$/kW/year
- where P = station size (MW)

For a direct geothermal heat supply, the following table indicates approximate costs.

Table G10: Approximate costs for direct geothermal heat supply from a dedicated field

Steam Flow, F (t/h)	Capital Cost, C ($M)	Operations and Maintenance Cost
0-12.5	C=8.3+0.031F	5.5% of capital cost per year
12.5-37.5	C=6.6+0.17F	
>37.5	C=4.5+0.22F	

3.4 ESTIMATED OVERALL COSTS

Overall station costs are summarised in Table G11.

In addition to the preceding analysis, geothermal energy can be a process heat source. Where heat users are simply tapping into a waste line (e.g. a plant drawing hot water from a reinjection line) then the costs of supply could be limited to the cost of connecting pipes and valves.

An alternative development scenario might be on the basis of a Geothermal Combined Heat and Power Station. If a steam supply is directly competing with a power station on a field controlled by an electricity generator then steam sold would be expected to earn similar rewards to electricity generation. A steam supply to a station (normally requiring around 7t/h of steam per MWe generated) will earn around 6c/kWh. This is equivalent to an energy income of $3.30/GJ of steam heat delivered.

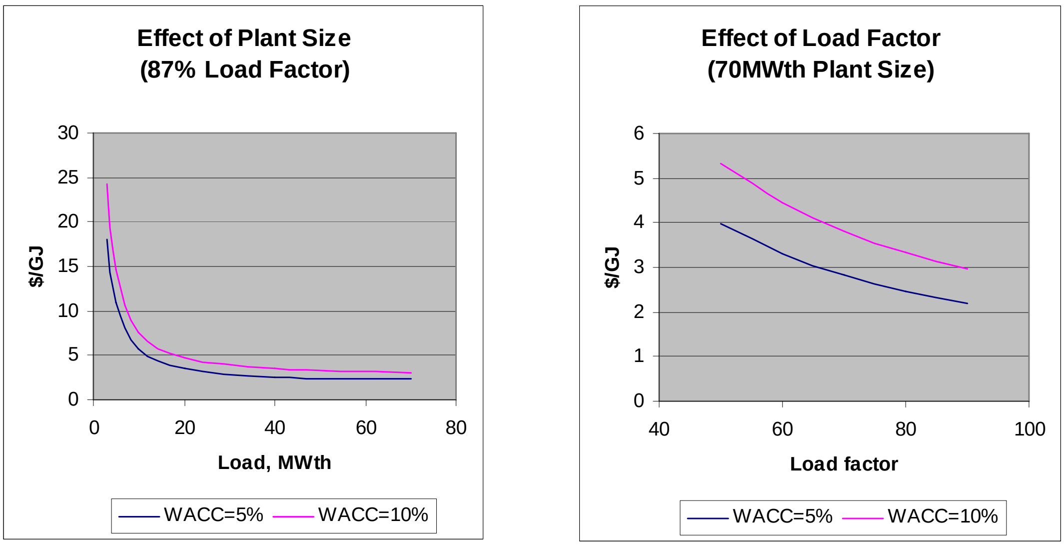
A heat load established beside a geothermal power station could expect to be charged a margin over this price depending on the overall business of the field developer and his contractual obligations. For instance, if the developer is also an electricity retailer then the electricity not generated increases exposure to risks of purchase on the spot market. Reduction in generation from these stations could allow the market price to be set by other generators bidding into the market at a premium, as happened in the 2001 winter. Non-retailing generators such as Tuaropaki Trust may still face some of these risks through other contractual arrangements.

The price of heat could be indexed to the spot price. However, following the 2001 winter price excursions, few energy users would risk a business fully exposed to the spot market.

In conclusion, a range of factors could influence the price offered and paid for steam for heating on a field with a power station.

Where a process heat plant is established on a dedicated geothermal field, the price of steam will be a strong function of load factor and demand. Current indicative values are shown in the following figures

Figure G2: Assessment of Energy Cost for a Geothermal Supply



In total, for a dedicated field, a heat development will need to be of large size and high load factor to offer steam at competitive prices to coal or gas. The target range is $5/GJ to $8/GJ.

3.5 NATIONAL SUPPLY CURVE DATA

The costs and uptake assumptions have been modelled and are given in the following table.

Table G11: Geothermal Cost Supply Curve

Supply Cost Data	c/kWh	Year 2012		Year 2025	
		GWh/y		GWh/y	
		WACC = 5%	WACC = 10%	WACC = 5%	WACC = 10%
High Confidence	2-4	200	200	200	200
	4-6	2,030	-	5,160	-
	6-8	80	1,790	80	4,780
	8-10	-	320		460
	10-12	-	-	-	-
Medium Confidence	2-4	200	200	200	200
	4-6	4,100	-	8,530	-
	6-8	150	3,620	150	7,750
	8-10	-	630	-	930
	10-12	-	-	-	-
Low Confidence	2-4	200	200	200	200
	4-6	17,670	-	17,670	-
	6-8	1,880	16,450	1,880	16,450
	8-10	-	3,100	-	3,100
	10-12	-	-	-	-

Cost supply curves have not been estimated for direct heat or non-power uses of geothermal energy.
The cost supply data are indicative of four types of development: a) Poihipi Rd reconsenting, b) new high temperature developments, c) Wairakei binary cycle (using waste heat), d) other binary cycle projects.

4. FURTHER RESEARCH AND OTHER ISSUES

4.1 NEW ZEALAND INFORMATION STATUS

There appears to be no comprehensive record of the use made of geothermal energy throughout the country, although most of the information must exist in various official documents, especially those of the Regional Councils. The collation of such information would be a valuable basis for encouraging better utilisation of the resources available. This data is especially lacking for low temperature resource utilisation as exists in places like Tauranga and areas north of Auckland.

There is no national assessment of low-medium temperature geothermal resources other than a record of springs.

Information on actual usage of low temperature resources is minimal and inaccurate.

4.2 TECHNICAL ADVANCES

Further technical research on the following topics should help to improve the range, efficiency and economics of geothermal energy utilisation:

- Geophysical techniques to better identify reservoir boundaries and the most productive zones within them.
- Refined reservoir testing, modelling and prediction of behaviour during production and reinjection.
- The treatment of dissolved chemicals for sale or their extraction for fluid use improvement.
- Drilling techniques directed at problems of lost circulation, casing and cementing integrity, and maximum fluid production per well.
- Technologists and financiers need to find ways of funding and developing geothermal developments that reduce overall costs and thus overcome the slow rate of development of geothermal resources.
- Research into effects of using aggressive geothermal resources.
- Watching brief on low-grade heat research and use that could be applied in New Zealand.
- Research and case studies on long distance transmission of geothermal fluids.
- Research on district heating options.
- Research on ground source heat pump applications with a water-heating element.

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CHAPTER 3 - WIND POWER

1. TECHNOLOGICAL INFORMATION

1.1 ENERGY RESOURCES

Wind is caused by atmospheric temperature and pressure gradients. It can be used in a variety of ways to provide electrical and mechanical power. The power available in the wind varies in proportion to the cube (i.e. the third power) of the wind speed. Small increments in wind speed can therefore significantly alter the energy available from the wind resource. Energy produced depends on the shape of the annual wind speed distribution curve, combined with the control and power generating characteristics of the wind turbine generator.

Wind turbine generators (wind turbines) can produce alternating current (AC) or direct current (DC) electricity as required by the application, e.g. DC for small remote power systems or AC for grid connections.

Wind turbines can be located on land, or at sea with towers fixed to the seabed or on pontoons. Normally at sea the wind is stronger, more consistent, and less turbulent. However, capital costs are greater, even more so in New Zealand as the seabed near the coast is likely to be more rugged and deep than for some European countries.

1.2 SYSTEM ELEMENTS

The main elements of a wind turbine generator are the turbine rotor system, the drive train and generator, support structure, and ancillary works.

Wind Turbine Rotor System

This consists of blades attached to a hub with blade control mechanisms, if any. Two configurations are common:

(1) The horizontal axis wind turbine (HAWT) with one, two or three blades, with the horizontal axis in line with the wind. This is the predominant commercially available turbine.
(2) The vertical axis wind turbine (VAWT), where the blades move around a vertical line, perpendicular to the wind direction. Machines of this type are no longer produced in significant quantities worldwide.

In the past decade, the configuration of wind turbines has almost exclusively standardised on three bladed horizontal axis machines with upwind rotors.

However, it is not possible to rule out advances in technologies that could see some alternatives, such as vertical axis or 2-bladed wind turbines, being installed in the future.

Support Structure

A typical grid connected machine stands 40-70 metres tall with rotor diameter of 40-70m. The tower normally supports a nacelle, which houses the drive train, generator and mechanical controls. Towers are normally tubular steel or concrete, or steel lattice. The bottom of steel tubular towers can accommodate electrical control and switchgear equipment.

Drive Train and Generator

The rotor hub is connected to an electrical generator through a drive train. Most drive trains include a gearbox. However, direct drive generators are becoming more common.

Ancillary Works

These normally include control cubicles and buildings, power distribution lines, transformers, substations, maintenance facilities and access roads.

Current Design Status

Commercially available wind turbines installed today are durable, efficient and proven. These turbines are the building blocks for wind farms.

About 95% of the turbines installed today are of the three-bladed design. The blades are rigidly mounted to a horizontal main shaft. The rotor is coupled to a generator either through a speed-up gearbox (e.g. Wellington Wind Turbine and Tararua Wind Farm), or directly for some variable speed turbines (e.g. Hau Nui). The average sized wind turbine installed has increased over time. Last year in Northern Europe it was approximately 1,100 kW (1.1 MW).

The most common turbine size range is in the 600 kW (0.6 MW) to 1.8 MW size range, with 2 MW and larger machines either under development or just entering production. The Tararua Wind Farm has 660 kW turbines. Table W1 gives an indication of dimensions related to generation capacity.

Table W1: Size/Generation Relationships of Modern Turbines

Rated Power (kW)	Rotor Diameter (m)		Hub Height (m)	
	General	Typical for NZ	General	Typical for NZ
600-750	40-50	45	40-50	45
800-1,500	50-65	55	50-65	55
1,500-2,000	65-80	70	65-80	70

Often, in low wind speed situations such as parts of Europe, larger rotors and/or taller towers are used to increase the energy yield of the turbines[2]. A 65 metre high tower might be used on a 600 kW turbine or a 1.8 MW turbine might have a 100 metre tower.

The wind turbine converts the available energy in the wind into useable utility grade electricity. It is designed to extract as much energy as possible out of the wind, up to the so-called rated wind speed. At the rated wind speed (for most turbines around 12-16 m/s) it produces its nominal or rated power. Between the rated wind speed and the cutout wind speed (for most turbines between 25-35 m/s), the wind turbine control system limits the output power to (on average) the rated power. In this operating window, the wind turbine “spills” excess energy.

[2] Wind speed generally increases with height above land.

1.3 SYSTEMS AND APPLICATIONS

Wind turbines are usually arranged in wind farms - multiple wind turbines forming a single managed unit in a generally contiguous area. The modular nature of wind turbines means wind farm capacities can be variable to suit land availability, load demand and other factors. Generally wind farms have a capacity of up to several MW. While not precluding the use of larger sized turbines, the medium size wind turbines (600 kW to 1 MW) are probably best suited to New Zealand conditions, due to cranage and transportation constraints.

1.4 TECHNICAL STATUS

Wind power technology is a mature technology and many commercial plants are available. However, there has not been enough experience with modern plant to fully prove energy output, O&M costs and plant lifetime and some other life cycle issues, particularly when the average site wind speed is as high as 10 m/s as is common in New Zealand. While a lot can be learned from the US and Europe, there is no high wind speed site in Europe or the US where a long record is available regarding the above issues. The wind turbines installed over the last few years in high wind speed sites in New Zealand have begun to build experience in this area.

As with most mechanical plant, O&M costs tend to increase through the life of a wind turbine. Overall life is unclear. It may be 15 to 25 years with possibly a major overhaul after 10 years. Height and power output (longer blades) are now increasing to take advantage of better wind conditions at higher elevation, and better economics with larger scale, particularly for offshore use. A better understanding of fatigue and other material stress issues helps this trend with fatigue now constituting a large amount of wind turbine R&D effort.

Unlike hydro power plants, the inflow of energy in a wind turbine is turbulent and chaotic, unsteady, varies with elevation (wind shear) and changes direction continuously. Modern wind turbines have to deal with this time and space variable energy inflow which together with the 100 million plus rotor revolutions, makes the fatigue life of a wind turbine an important issue.

New advanced wind turbines are likely to use one or more of the following technologies:

- Variable speed rotors to extract more energy with less power output variation
- Variable speed rotors to reduce fatigue loads in the rotor and drive train
- Direct drive (no gearbox)
- Advanced aerofoils
- Advanced materials
- Power electronics
- Flexible components
- Teetering rotors

The majority of wind turbine manufacturers are investigating or producing variable speed machines, using power electronics to supply a constant alternating voltage and frequency to the grid. The rotor speed of these machines varies over a wide range (e.g. 18-42 rpm). A number of these companies are investigating the possibility of eliminating the gearbox from the drive train by using advanced low speed electrical generators.

Advanced technologies, such as flexbeam rotors and teetering hubs, will reduce the stress amplitude cycles. However, the cost effectiveness of these methods has not yet been proven.

1.5 APPLICATION LIMITS AND SYNERGIES

Weak Grid

The adaptability of wind turbines to weak grid situations (which might exist in some areas of New Zealand where wind farms could be built) is being improved by the increased use of power electronics, particularly in variable speed machines. Variable speed turbines are generally able to control the import and export of reactive power, as well as supplying active power. Both reactive and active power is limited by the wind conditions at the time. The wind turbines at Hau Nui, Wairarapa are an example of this type of turbine. The grid characteristics of other turbines are also improving, with emphasis on soft start technologies, power factor correction, and flicker control. These features are somewhat counterbalanced by the increasing trend to larger turbines which, despite having improved power quality features, may not be able to be easily accommodated at grid points where the installation of a smaller turbine may have been possible.

High Wind Speed

Not all wind turbines available on the world market are suitable for New Zealand conditions. The low price of electricity in New Zealand means that only high wind speed sites (with hub height wind speeds of approximately 9-10 m/s) will initially be economically viable. Wind turbine designs are often optimised for lower wind speed European conditions (typically 6 to 8 m/s at hub height), and are therefore not always suited to New Zealand conditions. Nevertheless, it is possible to find a range of turbine designs suitable for most New Zealand sites and thus ensure that wind turbine supply contracts are competitive. Site-specific certification for some turbine models (taking into account wind speed, wind shear, turbulence, and terrain effects) may be required as the site conditions may not comply with the general certification for the turbine in some aspects.

Based on the above assumptions, it is highly likely that wind turbines installed in New Zealand in the coming few years will have rotor diameters of no less than 40 metres and tower heights no less than 40 metres[3].

Smaller Wind Turbines for Remote Applications

As well as the large grid connected wind turbine market, there is a market for wind turbines to supply electricity in remote locations. Examples include the supply of electricity to remote development such as houses, farms, lighthouses and telecommunications facilities. Unlike the larger grid connected wind turbines that generate electricity controlled with respect to voltage and frequency, small wind turbines for remote applications are usually optimised for battery charging. Inverters to generate grid quality electricity can in turn use this battery power.

[3] The 48 wind turbines installed at the Tararua Wind Farm have a 45 m hub height and 47 m rotor diameter.

Wind turbines for remote applications vary in capacity from a few hundred watts to about 10 kW. The consequent rotor diameters vary from less than a metre to about seven metres. Tower heights for these wind turbines typically range in height from 10 to 30 metres.

A turbine used to supply a single remote household would typically be rated at about 1 kW. Such a wind turbine may often not be placed in a resource-optimised location as proximity to the user is the most important factor. Also some of the energy from the wind turbine will not be able to be accepted by the system, e.g. if the batteries are already full. These two factors mean that the maximum effective capacity factor for such a turbine is likely to be approximately 30% or less. This compares with capacity factors of up to 50 percent for wind farm installations in optimum sites. In order to generate the same amount of electricity as the 32 MW Tararua Wind Farm, it is estimated that the installation of 50,000 small turbines would be required.

Hence the installation of small remote area wind turbines is unlikely to make a significant contribution to New Zealand's energy supply. Despite this, they are likely to be of increasing importance in providing energy services to areas where alternative energy supplies are uneconomic.

Any adverse environmental effects from remote wind turbines are likely to be from distributed generators and confined to the users themselves. Emission offsets from the generation of a unit of electricity generated by a remote wind turbine are likely to be higher than from a grid connected wind farm on a per kWh basis. This is because the energy generated displaces electricity that would have been generated by small relatively inefficient petrol or diesel engines.

Limitations

Despite earlier concerns that the characteristics of New Zealand's wind resource (such as extreme gusts) may have meant that there were limitations on the use of internationally developed wind generation technology in New Zealand, that has not proved to be the case for the majority of designs available. The operations and maintenance costs are related to the amount of energy generated, and so are higher in absolute terms than for typical European wind farms, but similar on a cost per kWh produced.

In practice, the limitations on the use of wind energy generating technology in the New Zealand context are more likely to be related to aspects not connected to the technology or the resource itself. Aspects include access to areas or lines, construction capacity (including availability of lifting equipment), grid characteristics, turbine and construction costs, and the ability to obtain resource consents.

The key issues include the need for backup electricity supplies and satisfactory integration with the national grid. These issues are similar for all electricity generating stations.

Wind power is not continuous so it cannot be relied upon solely unless there is an associated energy storage system (e.g. hydrogen production - fuel cell generation or hydro storage lakes). It is well suited to work with other sources of electricity generation that can cover any wind shortfall, and can be integrated up to a limit with a national grid system.

Grid systems dominated by thermal power generation will limit wind power penetration. The cost of significant spinning reserve (thermal turbines ready to instantly provide power) erodes wind power benefits. However recent research is showing that integration may be less of a problem than previously thought. For example, in Denmark, the installed wind capacity is approximately 20 percent of the total system capacity, which is dominated by relatively inflexible combined heat and power plants. Despite this, there have not been significant problems with the integration of wind into the system and Denmark is targeting an increasing share of wind power for its future electricity requirements.

The hydro domination of New Zealand's grid means the integration of wind power is even less of an issue than with thermal dominated systems. In fact, up to a point, there is a synergy between wind and hydropower. The lakes behind hydro dams could be seen as providing storage for wind energy (when wind energy is available hydro storage is increased). Wind energy has some potential to increase New Zealand’s reliability of supply (through a diversity of energy sources).

It is estimated that more than 30% of our present day electrical energy needs could be met by wind power before reaching the integration limit. In today's terms this would mean that about 2,500 MW can be installed. It is unlikely that such a large amount of installed capacity will be developed in the near future. These integration limits apply because, of all the wind turbines presently installed, the majority use induction generators to produce electricity. The utilisation of synchronous generators and power electronics will increase the possible grid penetration.

Sub-second, second and minute-by-minute power fluctuations of a single wind turbine are a function of the variability of the wind speed as well as the technical characteristics of the wind turbine. The nature of wind power is such that, while single wind turbines have fluctuating power output, this variation decreases dramatically as increasing numbers of units are installed. Fluctuations in power output have also been reduced by technologies that introduce drive train compliance, such as variable speed.

1.6 CRITICAL FACTORS

Scheduling the power generation of other generating plants and forecasting of the wind resource easily accommodates the hourly and daily variations in wind speed. The same smoothing effect on the variable energy contribution but on a longer timeframe occurs if wind farms are installed at different geographical locations throughout New Zealand.

The forecasting of wind speeds at particular wind farm sites for a time period of 15 minutes in the future can be achieved with a reliability of +/- 10 percent. The forecasting of tomorrow's weather can still be fairly accurate although the forecasting wind speed bands will be described only as "strong winds" or "moderate winds". These can be translated to expected amounts of wind energy and thus the expected alternative generation can be adjusted accordingly. Numerical weather forecasting models are improving in accuracy (due to advances in modelling software and hardware) and hence more reliable wind forecasts are also becoming available.

It is expected that the majority of future New Zealand wind farms will be smaller than 50 MW, and that these wind farms will be spread around the country. This spread will ensure that the existing electrical network can take timely action to ramp up (or down) additional capacity as the wind farm outputs change.

In addition, a network/wind farm operator will be able to forecast a possible high wind speed shutdown probability, and forewarn network operators. Shutting down parts of the wind farm, in a controlled manner to facilitate the smooth transition from wind power to conventional power generation, is thus possible. High wind speed shutdown situations may occur only a few times per year (depending on the site characteristics), but are the most problematic in regards to the power output variability because of the fast transition between full load to no load. It is noted that several manufacturers are addressing this issue and it is expected that this potential problem will be solved before it can become a significant problem in New Zealand. In a wind farm situation, not all the turbines in one wind farm will shut down simultaneously due to high wind speeds, as different parts of the wind farm may experience different wind characteristics.

The movement of weather systems influences daily wind speeds, however it is known that deterministic diurnal effects also play a role. On low lying or coastal land, it is observed that the wind speeds are sometimes significantly higher in the afternoon than at other times of day (this diurnal pattern phenomena is more marked at lower than higher altitudes). Diurnal wind patterns can be variable, but nonetheless system power planners can often use it to advantage.

1.7 ENVIRONMENTAL ISSUES

Environmental issues for wind turbines and associated wind farms give rise to uncertainties in the resource consent process

The ability to obtain acceptable resource consents for wind farms is regarded by some as a significant barrier to future development. At present one consented wind farm has not yet been built, with another where the first stage of about 50 percent of the consented capacity has been built. While it may seem that consents have not limited overall development of wind generating capacity the perception nevertheless exists, and may itself be beginning to be a barrier. Resource consents can take some time to obtain, with a reasonable lead time of two years or more, if there are appeals. If resource consent applications are being delayed now because of a perception of resource consent related difficulties within the industry, this may delay uptake should other barriers be reduced or removed in future.

There is a risk of not achieving acceptable resource consents, as most wind farm projects are discretionary activities (or sometimes non-complying) and must be evaluated in terms of national, regional and local policies. They are also evaluated on the basis of effects (as defined in the RMA), as well as under the more general "sustainability" criteria in Part II of the RMA. In practice, the process of consultation and participation under the RMA involves a significant level of risk as to whether consents may be able to be obtained or not.

One of the costs is that of public consultation and the provision of good documentary evidence of the potential visual and noise effects to surrounding landowners.

Sections 2.6 and 2.7 of this Chapter also provide further information on resource related environmental issues.

2. NEW ZEALAND RESOURCE INFORMATION

2.1 INFORMATION SOURCES

The information on the wind resource available and the possible uptake of this resource for electricity generation is taken from the recent EECA publication "Review of New Zealand Wind Energy Potential to 2015" (EECA, 2001).

Cost information has been sourced from recent published information on the cost of wind farms in localities such as Europe, United States, and Australia, as well as information from turbine manufacturers.

2.2 THE LOCATION OF RESOURCES

New Zealand is well suited to wind energy development since it lies across the prevailing north-westerly winds. It also has a long coastline, where sea breezes and lack of topographic interference result in consistent and relatively strong winds throughout much of the year. Most regions of New Zealand have a wind resource that could be practically developed.

In Europe there is increasing focus on the development of offshore wind power projects. The main incentive driving these offshore wind power developments is a lack of space for additional onshore developments, particularly in densely populated areas of Western Europe. While generally the wind resource is greater offshore, there are significantly higher construction and maintenance costs associated with such developments. In New Zealand these higher costs would not be fully offset by the assessed increased energy yields of offshore projects, and the delivered energy cost of offshore projects would be higher than land-based projects.

Such developments are unlikely in the short term and so this resource assessment does not include the offshore resource.

The EECA Report identified 13 general areas for land based wind farm developments throughout New Zealand, on the basis of available wind resource.

Another category "Distributed Generation" referring to the possibility of installing single wind turbines in locally windy places in areas that have not been specifically identified as having good wind resource, has also been considered.

Figure W1 shows the 13 areas considered suitable for wind farms.

The possibility of installing wind farms close to load centres, and thus reducing electrical losses incurred in the transportation of the energy through the national grid, is an important consideration in the uptake of wind energy development.

Other areas may have significant industrial load. These have not been specifically identified for the purpose of this report.

The large majority of load centres are near the coast. Since coastal winds are generally of higher speed and more consistent throughout the year than inland winds, wind farm sites most likely to be developed in the foreseeable future are likely to be in the coastal environment. The main exception is the area around the Manawatu Gorge, close to Palmerston North.

Figure W1: Location Most Suitable For Wind Energy Development

2.3 THE QUANTITY OF THE RESOURCE

Located in the "roaring forties" New Zealand has a very significant wind power resource. While in theory wind turbines could be installed that would be technically capable of meeting all future growth in electricity demand in the foreseeable future, cost and resource access would limit the uptake. The total long term potential has been assessed to be in the order of 100,000 GWh/year, three times our present level of national electricity generation. This assumes that 1% of the land area in New Zealand would be suitable for wind farming. However, because accurate site-specific resource information is unavailable or inadequate to confirm the supply cost-quantity relationships for most of this potential, neither the number of wind turbines needed to achieve this level of production, nor the cost of electricity generated from such a scenario has been calculated. This study provides an estimate based on the broad assessments of wind resource that have been made, rather than being compiled from site-specific data.

On the assumption that resource consents would be granted for specific proposals, and applying engineering judgement to the data that does exist, New Zealand could obtain during the next 15 years electrical energy equivalent to around 23% of present day consumption at costs, based on discount rate and exchange rate assumptions, of up to approximately 10 c/kWh.

Table W2 gives the calculated average annual energy production levels from the areas identified in Figure W1. The potential energy output is significant.

Table W2: Assessed Energy Potential from New Zealand Wind Resources

Region	Estimate Resource	Base Case	Base Case	Base Case
	(typical wind speed in m/s at 50 mAGL)	Area (km^2)	MW	GWh/y
1. Far North	8	35	350	1,070
2. West Coast Auckland	8	8	80	250
3. Coromandel/Kaimai Ranges	9	4	40	140
4. Cape Egmont/Taranaki Coast	7	30	300	710
5. Manawatu Gorge	10	10	100	410
6. NI East Coast Hills and Coast	8	30	300	920
7. Wellington Hills and Coast	10	25	250	1,030
8. Wairarapa Hills and Coast	9	30	300	1,080
9. Marlborough Sounds Hills	8	8	80	250
10. Banks Peninsula	8	10	100	310
11. Canterbury River Gorges	7	12	120	280
12. Inland Otago	7	30	300	710
13. Foveaux Strait and SE Hills	9	35	350	1,260
14. Distributed	7	40	400	950
Approximate Total		**300**	**3,000**	**9,500**

The base case (effectively a theoretical level of resource use) energy calculations used in this study incorporate the following assumptions:

- Thirteen areas with high wind resource were considered, plus a general "distributed generation" category covering any locally windy places throughout the remainder on the country. Offshore and island resources have been excluded.

- The technically viable resource estimated to cost up to about 10 c/kWh has been identified, i.e. mostly areas with good wind resource and existing infrastructure (transmission lines, roads, etc.).

- Some areas have been excluded due to significant resource consent issues, such as National Parks, areas of outstanding landscape or natural character values.

- Some areas have been excluded because of physical inaccessibility for construction and transmission.

- A conservative estimate of 10 MW per square km is used, which is based on a nominal three by seven rotor diameter spacing between wind turbines. An allowance has been made for local terrain, and buffer areas around roads and residential development within the wind farm.

- The energy generation is calculated from the approximate wind resource figure for the area, using an overall loss factor of 92%, which includes availability, wake, electrical, and other losses (e.g. hysteresis , air density, etc.).

Also built into the above estimates is general information on the resource itself.

Significant relatively flat areas, such as the Manawatu plains between Foxton and Palmerston North, lie near a strong wind locality listed in Table W2. While these are perceived as also having high winds, a very preliminary view is that the long-term average windspeed in such areas are likely to be significantly below (in energy yielding terms) the 7 metres per second identified in Table W2.

2.4 VARIABILITY OF SUPPLY

On an hour-by-hours basis the supply is extremely variable and can only constitute a non-firm energy source. Forecasting techniques are being developed to reduce the uncertainty associated with short-term fluctuations.

However, on a long-term basis the supply of energy from wind is a lot more certain. The annual wind pattern variation in New Zealand is typically around 10%, rainfall variation is typically around 20%. The wind resource variation can be to some extent forecast, calculated, and allowed for. Seasonal variation patterns are generally predictable. The annual resource for particular sites can be accurately predicted following a period of site-specific wind data collection and can be used to develop better forecasts regarding energy generation in New Zealand as a whole.

2.5 CURRENT UTILISATION OF RESOURCES

The utilisation of New Zealand's wind resource has begun in a limited way. Significant grid connected installations to date include:

[1] Hysteresis losses are associated with automatic shutdowns.

- Wellington Wind Turbine comprising one 225 kW unit
- Hau Nui, a 3.5 MW wind farm in the Wairarapa consisting of seven 500 kW wind turbines
- Tararua Wind Farm, a 32 MW wind farm on the Tararua Ranges near Palmerston North consisting of 48 x 660 kW wind turbines

All these projects are located in the lower North Island, where high wind speeds and reasonable proximity to electricity load centres make wind energy developments favourable.

These projects together are about 0.44% of the total installed generation capacity in New Zealand, and generate approximately 150GWh per year (just under 0.5% of the national electricity consumption). A number of smaller wind turbines are used to generate electricity for stand-alone .

2.6 INFRASTRUCTURE OBSTACLES

Proximity to transmission lines and subsequent cost of installing lines of adequate capacity is a very significant infrastructure impediment for future uptake.

Visual impact and acoustic noise effects of wind turbines are also significant issues for wind farms in New Zealand.

2.7 VIEW ON UPTAKE

While EECA 2001 identifies a “Base Case” and describes “Best Case” and “Worst Case” scenarios, the high and medium confidence levels used in this report do not correspond to the “worst case” and “best case” EECA scenarios. The high confidence level figures are a result of an assessment of an 80% possibility of uptake and the medium confidence level is based on a 50% possibility of uptake, with the significant influences being the ability to gain access to the best wind resources and resource consenting outcomes.

This change is because the EECA “worst case” scenarios represent basically minimum development of some low-intensity small-scale wind farms in less prominent areas, with distributed generation having little role. The high confidence level for this study is based on an uptake greater than a minimum. The EECA “best case” scenario assumes that areas that appear to have a favourable policy framework, few impediments for development under relevant plans and experience almost no impediment through the resource consent process, begin to be developed. The medium confidence level of this study provides for a 50% probability of investment occurring.

The results are given in Table W4.

[2] Examples include urban and remote households, a restaurant/restroom at the Rimutaka Hill summit, and widespread use on small boats.

3. ENERGY SUPPLY COSTS

3.1 CAPITAL AND OPERATING COSTS

The capital cost of wind farms has been assessed as $2,000/kW (2002) for the 25-50 MW range in New Zealand. The cost is relatively insensitive to size within this range, with access (roading) and transmission the major uncertainties.

Operating and maintenance costs are assessed as having two factors, one is MW related, the other kWh related. For a 50 MW wind farm the MW component is $1.4m pa, with an additional 0.6 c/kWh, giving a total of 1.3 c/kWh at a high wind speed site, and 1.6 c/kWh at a lower wind speed site.

3.2 SENSITIVITY (all confidence bands)

Table W3: Capital Cost Sensitivity

CAPITAL COST SENSITIVITIES								
Wind Potential (MW)								
	Estimated Lifecycle Cost Ranges c/kWh at 5% WACC							
Capex $/kW	2-4	4-6	6-8	8-10	10-12	12-14	14-15	Total
1,800	-	1,370	1,700	1,100	780	555	215	5,720
2,000	-	855	1,755	1,195	810	540	280	5,435
2,200	-	435	1,750	1,215	895	585	275	5,155
	Estimated Lifecycle Cost Ranges c/kWh at 10% WACC							
Capex $/kW	2-4	4-6	6-8	8-10	10-12	12-14	14-15	Total
1,800	-	-	1,165	1,300	995	715	315	4,490
2,000	-	-	640	1,325	1,055	730	360	4,110
2,200	-	-	230	1,250	1,080	785	345	3,690
Wind Potential (GWh)								
	Estimated Lifecycle Cost Ranges c/kWh at 5% WACC							
Capex $/kW	2-4	4-6	6-8	8-10	10-12	12-14	14-15	Total
1,800	-	5,025	4,700	2,300	1,310	780	270	14,385
2,000	-	3,285	5,305	2,735	1,485	830	385	14,025
2,200	-	1,740	5,715	3,020	1,785	980	405	13,645
	Estimated Lifecycle Cost Ranges c/kWh at 10% WACC							
Capex $/kW	2-4	4-6	6-8	8-10	10-12	12-14	14-15	Total
1,800	-	-	4,350	3,865	2,385	1,430	565	12,595
2,000	-	-	2,515	4,315	2,770	1,605	710	11,915
2,200	-	-	955	4,425	3,085	1,885	735	11,085

3.4 COST ESTIMATES IN THE FUTURE (2012, 2025)

The significant influences on capital cost of electricity generation from wind energy are:

- Cost/price of wind turbine generators (WTG) ex manufacturer
- Ease of access to sites/site terrain

- Exchange rate variations for imported equipment

Since, for a given wind speed, the energy generated by a wind turbine at a particular site is approximately proportional to the kW rating of the WTG, the capital cost estimate can be determined using the particular $/kW installed cost.

The cost index of WTGs ex manufacturer has been trending down as unit size has increased. This downward trend is lessening as the technology moves from well developed to a mature phase.

Allowance has been made for exchange rate variations from the base of 0.42 NZD/USD, and 0.48 NZD/Euro. Based on 2002 dollar values the unit costs for the period up to 2012 are related to a present capital cost of $2,000/kW reducing to $1,475/kW by 2012; those for 2025 are based on a capital cost of $1,225/kW, a reduction of 1.5% per annum. These reflect real reductions in capital cost arising from economies of scale and uptake.

3.4 ESTIMATED OVERALL COSTS

WIND SPEED - COST RELATIONSHIP at 5% discount rate					**WIND SPEED - COST RELATIONSHIP at 10% discount rate**			
Site Wind Range m/s	**Average Costs c/kWh**				**Site Wind Range m/s**	**Average Costs c/kWh**		
	2002	**2012**	**2025**			**2002**	**2012**	**2025**
6-7	10.75	8.50	7.25		6-7	15.0	11.5	10.0
7-8	7.75	6.25	5.5		7-8	10.75	8.5	7.25
8-9	6.25	5.0	4.5		8-9	8.75	6.75	6.0
9-10	5.50	4.5	4.0		9-10	7.75	6.0	5.25
10-11	5.0	4.0	3.5		10-11	7.0	5. 5	4.75

3.5 National Supply Curve Data

Table W4: National Supply Curve Data for Wind Resource

Supply Cost Data Capital:$1475/kW in 2012; $1225/kW in 2025	c/kWh	2012		2025	
		MW			
		WACC = 5%	WACC = 10%	WACC = 5%	WACC = 10%
High Confidence	2-4	-	-	170	-
	4-6	680	125	750	380
	6-8	475	520	425	510
	8-10	285	380	265	345
	10-12	205	250	175	230
	12-14	130	195	115	165
	14-15	65	80	45	65
Medium Confidence	2-4	-	-	395	-
	4-6	1,590	290	1,755	885
	6-8	1,115	1,210	990	1,190
	8-10	665	885	615	800
	10-12	485	580	405	540
	12-14	305	455	265	390
	14-15	155	190	110	150
Low Confidence	2-4	-	-	565	-
	4-6	2,275	410	2,505	1,265
	6-8	1,590	1,725	1,415	1,700
	8-10	950	1,260	875	1,145
	10-12	690	830	580	775
	12-14	435	650	375	550
	14-15	225	275	155	215

Supply Cost Data Capital:$1475/kW in 2012; $1225/kW in 2025	c/kWh	2012		2025	
		GWh/y			
		WACC = 5%	WACC = 10%	WACC = 5%	WACC = 10%
High Confidence	2-4	-	-	675	-
	4-6	2,310	500	2,245	1,405
	6-8	1,120	1,700	860	1,440
	8-10	505	945	400	730
	10-12	295	500	210	395
	12-14	155	330	115	235
	14-15	70	120	40	80
Medium Confidence	2-4	-	-	1,570	-
	4-6	5,395	1,165	5,235	3,280
	6-8	2,615	3,965	2,005	3,355
	8-10	1,180	2,200	935	1,705
	10-12	690	1,170	495	925
	12-14	365	765	270	550
	14-15	165	285	100	190
Low Confidence	2-4	-	-	2,245	-
	4-6	7,705	1,665	7,480	4,685
	6-8	3,740	5,665	2,865	4,790
	8-10	1,690	3,145	1,340	2,440
	10-12	985	1,670	705	1,325
	12-14	520	1,095	385	790
	14-15	235	405	140	270

4. Further Research and Other Issues

To gain a better understanding of the resource that is available at the lower wind speeds/higher unit costs, more definitive data on wind resource in selected (sample) localities should be acquired and analysed. Such work would be significant to gain an understanding of costs if there was a focus on introducing targets for the uptake of new renewables for energy supply.

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CHAPTER 4 – BIOMASS (WOODY)

1. TECHNOLOGICAL INFORMATION

1.1 ENERGY RESOURCES

Biomass can be considered as solar energy stored in the chemical bonds between the carbon, hydrogen and oxygen that make up plant material (cellulose, hemicellulose and lignin). Biomass can take many forms. While agricultural products are used as biomass fuels overseas, their potential within NZ is limited and they have been excluded from this chapter. Rather, this chapter focuses on the abundant woody biomass stock and its use.

New Zealand's climate and soils are ideal for biomass production. The categories of biomass with most potential for direct use as a low cost biofuel are:

- **Forestry arisings** - slash, tops and unmerchantable stemwood from trees harvested for saw or pulp logs. Arising may include the cutover depending on location of harvest.

- **Wood processing residues** – bark, sawdust, shavings, offcuts, etc. from processed wood for pulp, panel board, construction timber, furniture, etc.

- **Woody crop plantations** grown specifically for energy purposes, possibly in associated with land disposal of sewage and industrial effluent.

- **Scavenged firewood** from dead trees, prunings, tree removal and a range of other sources used as firewood.

There are numerous routes for conversion of biomass resources into useful forms of energy including liquid fuels. In this report direct combustion and gasification for process heat, electricity generation and co-generation of heat and electricity will be discussed.

When considering woody biomass energy some useful values to consider are (EECA 2001):

- Typical pine wood green density = 1,065 kg/m^3
- Calorific value of biomass from processing facilities = approx. 13 MJ/kg
- Calorific value of biomass from forest residues = approx. 9 MJ/kg

1.2 SYSTEM ELEMENTS

There are two stages in the utilisation of dry biomass resources: i.e. crop production and biomass harvest or recovery; and subsequent transport, storage, treatment (e.g. additional drying), and end use. Forest arisings and residues are produced as by-products of conventional forestry and wood processing.

Cutover remains on the forest floor where cut or trimmed. Forest arisings are produced at the landing with whole tree harvesting and can then be prepared and loaded for transport. A range of preparation and transport arrangements are possible.

Various management regimes are possible for short rotation tree crops. Short rotation woody crops grown intensively under a coppice regime are a means of sustaining biomass supply. Tree crops can also be grown in association with land-based wastewater treatment, the trees taking up nutrients in the course of treating the effluent. There has been some research into species selection and breeding programmes, and into hydraulic loading rates of effluent on to various energy crops and soil types.

Wood residues and woodchips (or wood comminuted into smaller chunks) can be mechanically fed into suitable heating plant. The resultant heat can be used directly or to raise steam for process needs or for electricity production via a steam turbine. The mechanical handling and burning of wood is a proven technology.

The conversion process to provide heat and electricity is commercially viable, there being many examples in the New Zealand wood processing industry. In the future it should be commercially feasible to directly turn the biomass fuel into a gaseous form prior to combustion (this is not the same as biogas from digestion). This approach would expand the use that can be made of dry fuel biomass, making it suitable for internal combustion engines, gas turbines, or a range of new and emerging technologies. This gasification avenue promises increased conversion efficiency, reduced emissions and better cost effectiveness.

1.3 SYSTEMS AND APPLICATIONS

Direct combustion of wood processing residues in 2-20 MWt boilers or furnace systems is a common form of conversion in the forest products industry producing steam, hot water, hot gases or hot air. Where surplus heat is available, electricity production may be feasible for use on site or for export to the grid.

Independent heat and power generating utility companies could produce electricity and/or process heat for sale, based on wood-fired technology. Installations ranging from 10 MW to 30 MW electric output appear to provide adequate economies of scale. The fuel source could be cutover, arisings, residues, tree crops or mixtures of all four.

On a smaller scale, biomass in the form of “firewood” is a significant domestic fuel used for space heating, water heating and cooking, particularly in areas where natural gas is not reticulated.

Considerable interest is developing in the potential for land disposal of effluent/sludge on to tree crops as a form of treatment. Further research is required but it is possible large areas of land will in future be used for energy crop production in association with effluent/sludge disposal.

1.4 TECHNICAL STATUS

ForestResearch in Rotorua has a world ranking research programme covering the full system from tree planting, fuel collection and energy conversion. Similarly, research lead by Massey University’s Centre for Energy Research is well respected domestically and internationally. Funding has been obtained for a range of applied studies in parallel with accelerating international research and development.

Harvesting systems, particularly for short rotation plantations have been developed overseas and some plant is in operation within New Zealand.

Techniques for drying, handling and storage of the material have been developed for a number of local applications. Wider development will occur once the relative economics improve.

A diverse range of technologies exists to convert woody biomass to useful energy, including combustion, gasification, pyrolysis and hydrolysis/fermentation systems.

- Combustion processes for heat applications consume most of the biomass for energy in New Zealand. Almost 80 percent is used within the industrial sector, particularly by pulp and paper plants and sawmills. Although combustion is a mature technology, refinements continue relating to emissions control and efficiency. Biomass combustion systems are available for a wide range of applications and systems with improved efficiencies and able to handle fuel with higher moisture contents are being further developed overseas. Fluidised bed combustion plants are in common use in Europe.

- Gasification technologies have reached the commercial evaluation phase with several plants overseas undergoing detailed evaluation and monitoring. Gasification, as a technology has been proven for coal applications (though is still not widespread) and is currently being adapted for biomass. Several biomass integrated gasification combined cycle (BIGCC) plant could have high replication opportunities. The gas produced (“syngas”) is a mixture of carbon monoxide and hydrogen, with a low to medium heating value. Gas cleaning issues (particularly related to silica content) are now being addressed in MW-scale demonstration plant. The technology is progressing rapidly to full large-scale commercial uptake, and is expected to take a dominant position as the means of large-scale energy conversion over the period covered by this report.

- Interest is currently growing in the use of biomass gasification products to produce Fischer-Tropsch liquids (FTLs). These liquids may eventually be produced at similar prices to petroleum-based diesel. FTL formulations tend to be cleaner burning than petroleum-based diesel (Suppes and Burkhart, 1999).

- Pyrolysis processes provide greater flexibility and higher conversion efficiencies compared to combustion, but capital costs are also currently excessive and technology is in the early stages of development. The product, pyrolysis oil, can be easily transported and thus separates the resource location from the site of use.

- Advances in the hydrolysis/fermentation of ligno-cellulose to produce ethanol/methanol and lignin are promising with future cost reductions claimed. The alcohol fuels can be used in present designs of internal combustion engines, new micro-turbines, or as a source of hydrogen for fuel cells.

Cogeneration of heat and power is particularly efficient where there is a demand for the heat. New Zealand has several successful examples. However development of future plants will be limited by the current price and structure of the energy market, unless investment costs improve for embedded or distributed generation opportunities.

Co-firing of biomass with coal presents an effective means of displacing a portion of fossil fuels at minimal cost for heat generation. Opportunities for co-firing in the electricity sector are limited. The co-firing of coal or gas in a biomass plant is likely to be more attractive as it can be used to overcome short-term shortages of biofuel or, if part of the fuel specification, can allow significant capital cost reductions.

1.5 APPLICATION LIMITS AND SYNERGIES

A difficulty with woody biomass has been the inconsistency of fuel quality. As a waste stream it can have a range of particle size, moisture content and other characteristics. This variability adds significantly to the costs of handling. The development of a business focussed on supply of a woody biomass fuel (CHH Biogrid) could lead to standard fuel products being offered on the market for use outside the forestry industry. A wide uptake is needed in this new energy market.

One issue that may become more important in the future is the potential use of forest arisings and other wood wastes as material input to further manufacture. Competition for the resource between production and energy end uses could become one of the many potential factors limiting the use of wood waste as an energy source. Already bark is being used as a raw material for garden products. It is believed that as sawdust is generally a homogenous product it will soon be a feedstock for manufacture. Wood waste remaining for use as an energy fuel is likely to be limited to the scrap from harvesting and processing.

Fuelwood crops could be grown close to heat and electricity demand centres, reducing transport cost and transmission losses. Where wood drying at source is viable this may reduce transport costs or increase the fuel catchment area. Generally crops could be harvested all year round, although wet ground conditions may be a restriction at some times. In any event the wood can be stored until needed.

The bulk of forest arisings and residues would be generated in the Central North Island, but most regions would have access to a significant resource of this type. Arisings and residues, as well as being suitable for storage, are generated all year round. Nevertheless, there is some risk of fire associated with large stockpiles of fuel.

Consequently heat and power could be obtained from dry fuel biomass in most regions all year round. The major issue with dry fuel biomass is finding a suitable heat or power load close to the biomass source, as transport costs are a limiting factor.

1.6 CRITICAL FACTORS

The biomass cost ($/GJ of useful energy output) is particularly sensitive to:

- fuel feedstock production costs
- harvesting costs
- moisture content
- fuel quality (including contamination issues)
- transport distance
- capital cost of equipment (especially fuel handling equipment)
- labour requirements
- conversion efficiencies, and
- load characteristics.

Input feedstock costs range from a negative cost for disposal of wastes, through $20-30/tonne for residues used on site, to $40/tonne for processed biomass transported some distance to the point of use. Green biomass has a relatively low energy content (7-10 MJ/kg), which gives problems of transport, storage and handling and hence increased costs/GJ. Often biomass is difficult to recover, is poorly distributed, and is produced some distance from the markets. The exceptions are wood processing residues used on site and energy plantations grown near to areas of demand.

1.7 ENVIRONMENTAL ISSUES

In carbon accounting, biomass is assessed as being fully converted to CO_2 at the time of harvesting for Kyoto (post 1990) forests. Where biomass developments are sustainable (as they would be for any managed plantation forest), any combustion of waste biomass is counted as making a zero contribution to CO_2 emission, qualified by the small amount of fuel used in harvesting, comminution and transport.

Uptake of wood waste products has not been high, with almost no use of cutover and arisings, and only partial use of wood processing residues. In most cases wood is left on the ground to decay. In the case of wood processing residues, there can be a cost associated with simple combustion or landfilling (with subsequent methane emissions).

There has been significant new planting in recent years. This will both increase the availability of a potential fuel, and increase the need for disposal of the waste product.

Burning firewood in domestic burners can be an efficient resource use compared with power generation from the same biofuel, and can be clean burning if properly designed.

2. NEW ZEALAND RESOURCE INFORMATION

2.1 INFORMATION SOURCES

A range of reports has been published on woody biomass. The 1993 Ministry of Commerce report has formed the basis for this section, modified by the findings of the 1996 EECA/CAE report, and the more recent 2001 EECA Biomass report. In addition, valuable summaries are available on a range of conversion technologies in a recent Massey report (Gigler et al 2001). Electric Power Research Institute (EPRI) have published useful technology reports in the intervening years (EPRI 1997, EPRI 1998), while a European technology assessment has been published recently (Dornburg and Faaij 2001). Together, these last reports have lead to a reassessment of gasification in this report. This work has been qualified by advice from practitioners and calibrated against advanced development proposals.

2.2 THE LOCATION OF RESOURCES

New Zealand forestry production is almost entirely from forest plantations as opposed to native forests (0.4%). The dominant species is radiata pine (90%). The following table indicates forestry concentrations. In addition there will be concentrations of waste wooden construction and demolition materials at all major population centres. The following table shows projected wood supply while figure BMW1 shows the physical location of collections of forests, processing centres and boundaries between wood supply regions.

Figure BMW1: Map of New Zealand Woody Biomass Resource

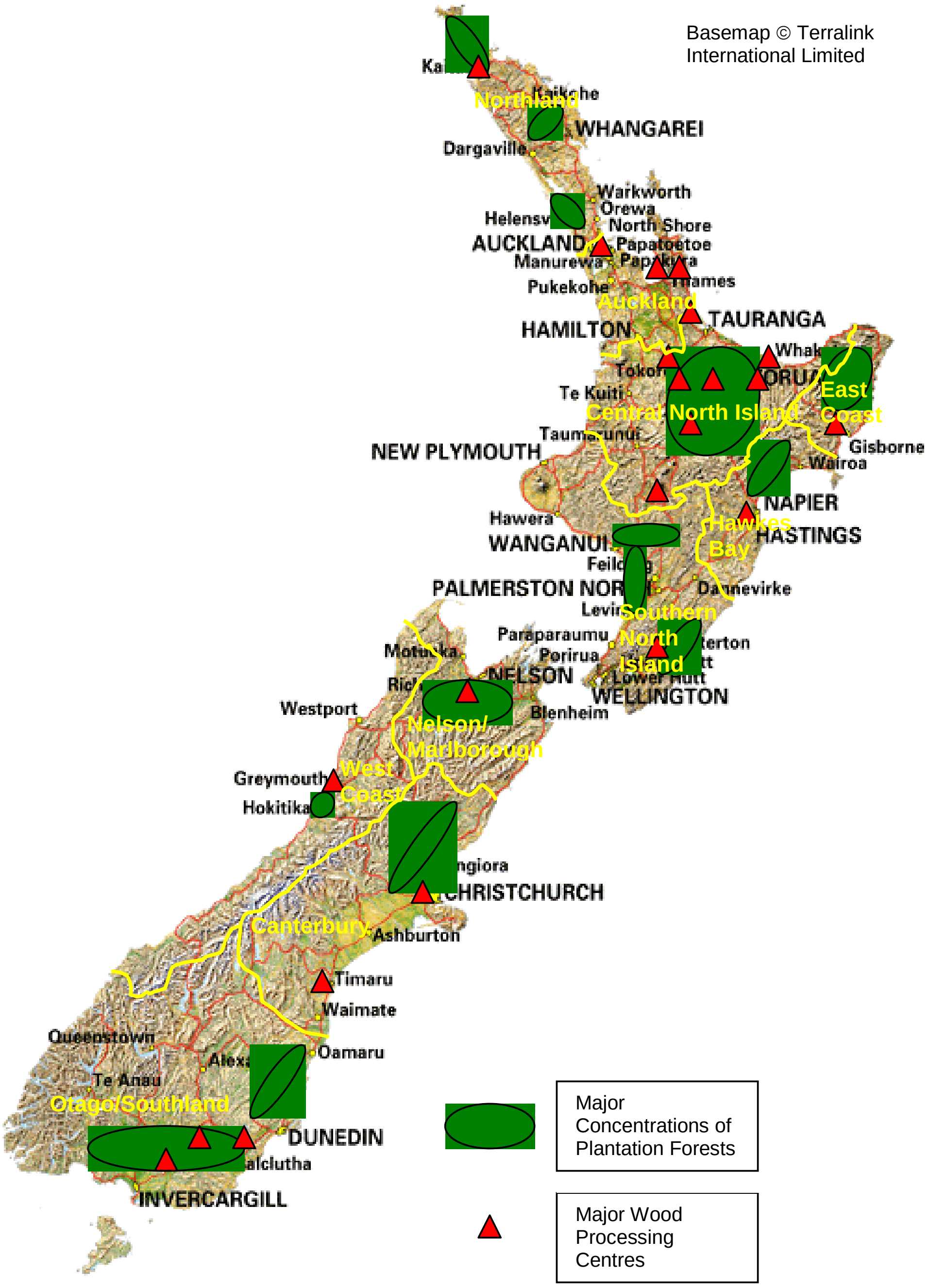


Table BMW1: Projected Wood Supply by Region (000m^3 per annum) (from NZFPI Map 2001)

	2000[1]	2011-2015	2021-2025
Northland	1,238	4,206	4,200
Auckland	657	948	1,073
Central North Island	10,317	11,586	12,398
East Coast	656	2,805	4,249
Hawkes Bay	800	2,365	3,267
Southern North Island	648	2,394	4,695
Nelson/Marlborough	1,402	2,874	3,362
West Coast	240	387	385
Canterbury	604	1,254	1,688
Otago/Southland	1,800	2,461	3,578
New Zealand Total	**18,362**	**31,281**	**38,894**

1. New Zealand Forest Products Facts and Figures 2000/2001

As can be seen, there have been major expansions of forestry operations with considerable growth outside the traditional plantation area in the Central North Island. These new plantings are largely by small operators. A processing industry should grow to handle the new product.

2.3 THE QUANTITY OF THE RESOURCE

Forest Arisings

This resource was discussed in some detail in the latest EECA publication on woody biomass. There is debate over whether cutover should be included in the resource, as it is more expensive to harvest. Assessments on a cutover inclusive and exclusive basis by region have been made (EECA 2001).

On a percentage basis, residues including cutover are forecast to decrease from around 16% by weight currently to less than 14% of the harvested volume by 2025 due to a trend toward whole tree processing. This assessment still excludes cutover on land that is too steep to harvest.

Excluding cutover and only considering material collected at landings and centralised extraction points, published assessments indicate a rapid increase in the quantity of residues from around 2% by weight now to 3.7% of the harvested volume by 2012 and beyond, largely due to whole tree processing using log haulers (EECA 2001). Estimates are summarised in Table BMW2 below.

Note that while some trials have been undertaken on use of forest arisings at Kinleith, and some scavenging may occur, this resource is essentially unused as a fuel. There may be competing demand for this resource for chipping if prices for pulp and paper, and particle and fibreboard products grow.

Wood Processing Residues

Wood processing residues arise from sawmilling, pulp and paper manufacturing and panel production processes. Typical residue streams consist of sawdust, shavings, off-cuts, chip fines, bark, chip and log-ends. In 1999 there were 3 fibre board plants, 2 particle board plants, 3 plywood plants, 7 pulp and paper plants, 7 veneer plants, 2 paperboard plants and 100 substantial sawmills. Since then three LVL plant have been built and there have been other substantial increases in the size and performance of processing plant.

In recent years as forest harvest volumes have increased, the percentage of wood locally processed has dropped from 95% to 70%. The projection for wood processing residues given in the EECA Woody Biomass Report (2001) suggests that processing residues will stay fixed at 23% of total log volume harvested despite trends of decreasing wastage, implying an increasing percentage of local processing. This is clearly assuming that there will be strong incentives to process the timber onshore rather than simply exporting as logs. Of this residue, slabwood and chips from sawmilling can be reused in other processing activities. About half is available for energy production, with half of this currently consumed by the forestry industry. Projections are given in the Table BMW2.

Note that there are competing non-energy uses for this residue, and that some residue may have unfavourable combustion characteristics, e.g. propensity for slagging.

Table BMW2: Assessed Biomass Resources

	Plantation Forest Harvest		Resource Available				Energy Value		
Year	Harvested Volume (Mm^3)	Processed Volume (Mm^3)	Forest Residues Including Cutover (Mm^3)	Forest Residues Excluding Cutover (Mm^3)	Total Wood Processing Residues (Mm^3)	Residue After Forestry Industry Use[1] (Mm^3)	Forest Residues Including Cutover (PJ)	Forest Residues Excluding Cutover (PJ)	Process Residues (PJ)
1965	4.3	3.9	0.8	0.1	1.0	0.7	6.9	0.8	8.0
1971	7.1	5.2	1.4	0.2	1.6	1.1	11.5	1.3	13.4
1974	7.6	6.1	1.5	0.2	1.8	1.2	12.3	1.4	14.3
1976	7.3	6.7	1.4	0.2	1.7	1.1	11.7	1.3	13.6
1977	8.6	7.6	1.6	0.2	2.0	1.3	13.9	1.5	16.1
1984	8.5	8.1	1.6	0.2	2.0	1.3	13.7	1.5	16.0
1988	9.0	8.5	1.7	0.2	2.1	1.4	14.4	1.6	16.8
1994	14.8	10.3	2.8	0.3	3.4	2.3	23.5	2.6	27.6
1995	16.0	11.2	3.0	0.3	3.7	2.4	25.2	2.8	29.8
1996	16.6	10.8	3.1	0.3	3.8	2.5	26.1	3.0	31.0
1997	15.9	10.4	2.9	0.3	3.7	2.4	24.9	2.8	29.7
1998	16.6	10.8	3.1	0.4	3.8	2.6	25.9	3.0	31.2
1999	15.7	10.8	2.7	0.3	3.6	2.3	23.0	2.8	28.4
2000	18.0	12.5	2.9	0.4	4.1	2.6	24.8	3.2	31.5
2003	26.3	18.4	4.0	0.6	6.0	3.6	33.8	4.7	44.2
2008	30.8	21.6	4.4	1.1	7.1	4.0	36.8	9.1	48.3
2013	31.3	21.9	4.4	1.2	7.2	4.0	37.1	10.0	48.8
2018	33.6	23.6	4.6	1.2	7.7	4.2	38.8	10.5	51.4
2023	38.9	27.2	5.3	1.4	8.9	4.9	44.9	12.2	59.4

1. This residue is Wood Processing Residue after Forestry Industry Use, and does not include Forest Residues
2. Projections include estimates from Forest Industry Engineering Association with other assumptions based on the text above.

Plantation Fuelwood

Current estimates of short rotation forestry (SRF) in New Zealand are around 1,000-2,000 ha grown mostly for domestic firewood. There may in future be a small energy market associated with forest residues for Eucalypts grown for pulp forests (EECA 2001).

The resource may become plentiful if energy costs rise significantly to justify land conversion. Forests based on nutrient removal from wastewater have a 3 to 7 year rotation (EECA 2001). Others have rotations of 7 to 12 years to yield a greater proportion of stemwood.

Generally there is an expected yield of around 20-30 oven dry tonnes per hectare per year (EECA/CAE 1996).

Land availability is difficult to determine due to competing uses. The EECA/CAE 1996 report assumed that 5,000 ha of land would eventually be dedicated to plantation fuelwoods, and would remain constant into the future. On this basis there could be a supply of around 2 PJ/year spread over several sites.

Equivalent fuel cost is discussed in section 3.1. The forecast cost for plantation firewood is not expected to be attractive for either commercial heat supply or electricity generation. This resource, if developed is most likely to displace other domestic firewood sources.

Firewood

Current firewood estimates are crude. As outlined above, about 1,000-2,000 ha of SRF has been developed for domestic firewood. Applying the rule of 20 oven dry tonnes/ha/year implies 20,000-40,000 t/year. In 1992, the Department of Statistics showed that about 300,000 t of wood was consumed annually (equivalent to about 5.4 PJ/year). This is sourced from land clearing, forest arisings, small sawmills, wind thrown trees, and general scavenging. This wood source can be contaminated with soil and other vegetation (EECA/CAE 1996).

Another major potential source of wood is from construction and demolition material sent to landfills. About l7% of landfill waste is wood (MfE pers comms 2001). With 3.85 million people producing 2.46 kg/person/day, this implies 240,000 t of wood is delivered to landfills annually (equivalent to 4.3 PJ/year).

Domestic use of firewood is expected to be static given possible uptake in some areas, while Christchurch in particular will see a reduction.

2.4 VARIABILITY OF SUPPLY

As has been discussed, there can be considerable competition for residues and for land for SRF crops. This can lead to problems with variability in both quality and quantity of supply. In the case of biofuels, quality can have considerable impact on success of fuel handling as well as on energy derived.

The composition and mix of process residues will change significantly over time as waste is recognised as feedstock for further processing. The variability of biomass as fuel supply can have significant problems for the design of energy handling and conversion plant.

2.5 CURRENT UTILISATION OF RESOURCES

Forest Arisings

There is no significant use of forest arisings for fuel.

Wood Processing Residues

Currently about 1.3Mm^3 per year of wood processing residues are used by the forestry sector for energy production, i.e. about 13 PJ/year. A further 13 PJ/year is based on the burning of black liquor at pulp and paper mills giving a total figure of 26 PJ/year (EECA 2001).

The largest users of wood processing residues are the major pulp and paper mills at Kinleith and Kawerau. These include black liquor recovery facilities. A notable plant is the 40MW cogeneration plant commissioned at Kinleith in 1997. The pass-out steam turbine receives steam from two existing recovery boilers and a new boiler capable of being fired by wood waste or natural gas.

Table BMW3 is a partial list of wood waste-fired plant that was extracted from the New Zealand Cogeneration Association website. Table BM4 is a partial list of major heat plant (PA Consultants 2001). It excludes the large number of smaller boilers linked to many kiln-drying operations. In 1998 approximately 45% of all timber that was kiln-dried used wood or bark as the fuel source (EECA 2001).

The Bioenergy Association of New Zealand has advised that over the last three years approximately 40 MWth of new heat plant using biomass have been installed annually.

Table BMW3: Wood Waste-Fired Cogeneration Plant

Plant	Location	Year Commissioned	Turbine Size (MW)	Typical Output (GWh/year)
Blue Mountain Lumber Co	Conical Hill	2000	1.6	2.5
Carter Holt Harvey Pulp and Paper	Kinleith	1997/8	40	?
Findlater Sawmills Tussock Creek	Winton	1997	0.315	?
Fletcher Challenge Forests	Waipa	1985	3.5	30
Tasman Pulp and Paper Co (now Norske Skog)	Kawerau	1954,1973	12.5, 23.0	?, 114

Table BMW4: Principal Wood Waste-Fired Boilers at Timber Processing Facilities[1]

Company	Plant Type	Location	Boiler Capacity (MWth)	Grate Type
Tasman P&P	Pulp & Paper	Kawerau	100	Travelling, recovery
Nelson Pine	MDF	Nelson	90	Kablitz, reciprocating
CHH	Pulp & Paper	Kinleith	70	Kablitz, recovery, reciprocating
CHH	MDF	Ashley	40	Travelling
JNL	Triboard	Kaitaia	38	
Rayonier	MDF	Mataura	35	
JNL	Veneer/LVL	Gisborne	34	Tipping
JNL	Veneer/LVL	Masterton	28	Tipping
CHH	Board	Whakatane	25	
FC Forests	Sawn Timber	Waipa	25	Kablitz, reciprocating
Pan Pacific	Pulp/Sawn	Whirinaki	25	Pinhole
FWP	Particle-board	Kumeu	20	
FWP	MDF	Taupo	17	
Blue Mountain	Sawn Timber	Tapanui	10	
Tachikawa	Sawn Timber	Rotorua	8	Hydrograte
Total			**620**	

1. Source: PA Consulting Group (2001). *Transition to Renewable Sources of Energy.* Report prepared by PA Consulting Group for Ministry for the Environment and Energy Efficiency and Conservation Authority, August 2001.

Plantation Fuelwood

The current assessed use, outside of firewood is zero (EECA 2001).

Firewood

Based on data from Department of Statistics about 5.4 PJ/year (based on 300,000 t of wood) was consumed in 1992 and is believed to represent an ongoing value (EECA/CAE 1996).

2.6 INFRASTRUCTURE OBSTACLES

Building a business around commercial development of waste wood products has proved a hurdle.

The resource has a lower energy content than coal or natural gas so cost of transportation is a significant obstacle. The following table (EECA 2001) gives indicative transport costs.

Table BMW5: Indicative Cost of Transport for Varying Distance ($/green tonne)

	5 km	25 km	50 km	75 km	100 km
Processed in forest, on highway cartage	1.6	5.5	8.0	10.5	12
Processed at plant, off highway cartage	1.4	4.0	6.0	NA	NA

Note: processing refers to chipping or tub grinding the forest residue material
NA = not applicable

Fuel handling can be a costly problem. The best system is a function of input fuel quality. Reliable input fuel quality has not generally been achieved because of variations in fuel composition.

The capital cost of plant burning gas and coal is less than the cost of plant burning biomass - lowered by both fuel handling costs and the costs of boilers to combust higher energy fuels. Fossil fuels are more convenient, and of reliable quality, but this advantage is offset by the lower cost of biomass fuels.

A review of figure BMW1 in section 2.2 will show that the forests tend to be remote from some major population centres so that transport cost could discourage use of the arisings fuel. In contrast, large wood processing centres can be nearer major towns and cities reducing transport costs for the low cost process residue fuel.

2.7 VIEW ON UPTAKE

View on Resource

Woody biomass resource will have competing non-fuel uses within the forestry industry. This may see increased demand for uniform products such as sawdust. As a fuel for power or heat, woody biomass will continue to compete with coal and gas. Any move to pass through carbon credits to renewable energy uses could enhance uptake. However, major changes in demand characteristics are not foreseen.

A conservative view on uptake is given in the EECA 2001 report. This could see a net increase in primary energy use from wood process residues of 6 PJ by 2012 and 12 PJ by 2025.

Section 2.3 gave a view that firewood use will remain static, though plantation fuelwood could supply up to 2 PJ of this energy.

The above estimates are high confidence positions.

At a more optimistic level (medium confidence) greater use would be made of processing residues, say an extra 10 PJ, and extensive use would be made of forest arisings at landings. Assuming half of the landing material is collected implies further fuel value of 5 PJ by 2012 and 6 PJ by 2025.

The extreme position would be that a large portion of the forest residue would be taken up. The estimate below is based on values in Table BMW2 less current usage of 13PJ.

Table BMW6: Assessed National Resource Uptake above Current Levels

	Year 2012			Year 2025		
Source of Increase	**High Confidence**	**Medium Confidence**	**Low Confidence**	**High Confidence**	**Medium Confidence**	**Low Confidence**
	PJ	**PJ**	**PJ**	**PJ**	**PJ**	**PJ**
Firewood and Plantations	-	-	-	-	-	-
Process Residues	6	16	36	12	22	46
Arising (excl. cutover)	-	5	10	-	6	12
Arising (cutover)	-	-	27	-	-	33
Total	**6**	**21**	**73**	**12**	**28**	**91**

View on Use

In future, to ensure control on quality of processed wood, there will be high demand for wood drying. There is no clear view on how the forest processing industry will develop. Much of the new growth is by small private forestry operations, but processing is likely to be contracted to major processors. In some cases this will require new facilities in certain regions, with some of that new plant being installed now.

As a crude approximation, from the Energy Data File (MED 2001) about 20% of primary energy from wood processing residues is currently used for electricity (cogeneration).

From recent studies, a saw mill will require a boiler capacity of approximately 40 MW/Mm^3 of log input, which will consume about 1.1 PJ/Mm^3 of log input to the mill (as opposed to 2.0 PJ/Mm^3 of timber to be dried). From the EECA 2001 report approximately 45% of timber drying uses wood waste as a fuel. Drawing from the table in section 2.2, assuming that new mills will handle new processing, and that 70% of the log harvest is locally processed implies the following need for new heating.

Table BMW7: Projected Additional Heating Demand Using Wood Over Present Demand

2012		2025	
Boiler Capacity (MWth)	**Energy (PJ)**	**Boiler Capacity (MWth)**	**Energy (PJ)**
163	4.5	259	7.1

These estimates are consistent with the forecast energy resource uptake and would allow a continuation of past practice of 20% resource energy from process residue to electricity generation with the remainder largely for process industry use, and a small amount of other use.

Additional resources would largely be available for electricity generation (or could be directed to heat supply if a market outside forestry develops).

Reviewing forest processing heating demands on a regional basis, there is unlikely to be a requirement for boilers significantly over 30 MW.

An approximate split of sizes is needed for a cost supply curve. Reviewing the size of previous mills, and assuming there will be a trend towards larger processing facilities then the following boiler size estimates may apply: 10% of capacity may be 2MWth, 35% of capacity may be 5MWth, 45% of capacity may be 10MWth and 10% of capacity may be 30MWth.

At the medium confidence level, a large portion of energy is available at low price in excess of forest processing demands. All this additional energy is assumed to be directed to electricity generation (but could be used for heat if a market developed). In section 3, a case is made that future electricity generation is likely to be via gasification, as opposed to simple combustion. On this basis there should be sufficient resource for 10MWe power stations in most regions with 20 MWe and 40 MWe stations possible in the Central North Island. *ForestResearch* suggests that if the wood process industry expands to process the increased wood flow than electrical demand for this plant alone could amount to 250 to 300 MWe.

The extreme low confidence position could see four to five times the medium confidence resource developed for electricity generation. On this basis 60MWe stations could easily be supported in the Central North Island.

This discussion has focussed on the forestry sector, but the scenario could be readily changed if marketing of a reliable woody biomass fuel product outside the forestry industry is successful. There are some existing markets e.g. Feltex in Christchurch. Large dairy factories are another potential (though reluctant) market.

Summary of Uptake Scenarios for Modelling Purposes

The following options will be used for modelling purposes. These are potential options and represent a limit on uptake. Actual uptake will be driven by price considerations.

Year 2012 High Confidence

Power Station - 1 x 20 MWe fed by process residues
Heat Plant - (total of 4.7 PJ from process residues equivalent to 171 MWth)
- 8 x 10 MWth plants with process residue fuel
- 14 x 5 MWth plants with process residue fuel
- 10 x 2 MWth plants with process residue fuel

Year 2012 Medium Confidence Increment

Power Stations - (total of 15 PJ from 67% process residue/33% arisings equivalent to 180 MWe)
- 1 x 40 MWe - 67% process residue/33% arisings
- 2 x 20 MWe - 67% process residue/33% arisings
- 10 x 10 MWe - 67% process residue/33% arisings

Year 2012 Low Confidence Increment

Power Stations - (total of 52 PJ from 38% process residue/10% arisings/52% cutover equivalent to 770 MWe)
- 5 x 60 MWe - 38% process residue/10% arisings/52% cutover
- 6 x 40 MWe - 38% process residue/10% arisings/52% cutover
- 7 x 20 MWe - 38% process residue/10%arisings/52% cutover
- 9 x 10 MWe - 38% process residue/10% arisings/52% cutover

Year 2025 High Confidence

Power Stations - 2 x 20 MWe fed by process residues
Heat Plant - (total of 9.3 PJ from process residues equivalent to 338 MWth)
- 1 x 30 MWth plants - 100% process residue
- 15 x 10 MWth plants - 100% process residue
- 24 x 5 MWth plants - 100% process residue
- 19 x 2 MWth plants - 100% process residue

Year 2025 Medium Confidence Increment

Power Stations - (total of 16 PJ from 63% process residue/37% arisings equivalent to 230 MWe)
- 1 x 40 MWe - 63% process residue/37% arisings
- 2 x 20 MWe - 63% process residue/37% arisings
- 15 x 10 MWe - 63% process residue/37% arisings

Year 2025 Low Confidence Increment

Power Stations - (total of 63 PJ from 38% process residue/10% arisings/52% cutover equivalent to 920 MWe)
- 5 x 60 MWe - 38% process residue/10% arisings/52% cutover
- 7 x 40 MWe - 38% process residue/10% arisings/52% cutover
- 10 x 20 MWe - 38% process residue/10% arisings/52% cutover
- 14 x 10 MWe - 38% process residue/10% arisings/52% cutover

3. ENERGY SUPPLY COSTS

3.1 CAPITAL AND OPERATING COSTS

A range of technologies exists for converting biomass to energy. Current practice uses simple combustion methods. Cofiring with coal may be possible with retrofits for some existing thermal plant. This report compares expected gasification plant unit costs with combustion plant unit costs and shows that this is about to be cost competitive. The analysis through this report assumes gasification will become the dominant technology over the period of this report.

Cogeneration would normally be used in preference to dedicated heat or power plant. The following report models electricity plant from which steam can be redirected for process purposes.

Fuel Cost

The range of biofuels can be adapted to any technology.

Forest Arisings
The EECA/CAE 1996 report gave fuel estimates in the range $3/GJ to $8.70/GJ and allowed for collection from cutover as well as landings with haul distances up to 80 km. The EECA 2001 report emphasised site-specific aspects including transport and in-forest processes. An example given for Nelson shows landing only residues in the $2.30/GJ to $3.00/GJ range. Residues including cutover would normally be in the range $2.70/GJ to $4.00/GJ. For the purposes of assessment, calculations in this report will be based on $2.7/GJ for landing material and $3.4/GJ inclusive of cutover.

Forest Processing Residue
The EECA 2001 report pointed out the potentially high cost of waste disposal where the residue would have a negative cost if used as a fuel. For assessment purposes the EECA 2001 report assumed a value of $0.25/GJ assuming most residue is used on-site or nearby. This assumes that current landfill costs prevail. An increase in landfill cost will lower the cost of the process residue.

Plantation Fuelwood
The EECA 2001 report gave the value of SRF products as $34-$54/tonne (fresh weight) at the farm gate. With a heat value of 8 MJ/kg this equates to a price of $4.3/GJ to $6.8/GJ. Allowing for transport, this could be $5.3/GJ to $7.8/GJ. (The EECA/CAE 1996 report worked on a fuel cost of $2.5/GJ to $5.0/GJ.) A value of $6.50/GJ has been used for assessment in this report.

Firewood
The EECA/CAE 1996 report assessed firewood as costing $2.6/GJ to $25.5/GJ.

Process Heat

One of the greatest woody biomass opportunities is as a heat source in the forest processing industry. An analogy can be drawn with the use of bagasse in the sugar industry. There is already high utilisation of waste wood products in the pulp and paper industry.

For New Zealand wood processing operations, most boilers are in the 2 to 20 MWt size range. Conversion costs given in the MOC 1993 report have been reviewed. Materials handling is now thought to be a greater proportion of costs. Capital costs for 2 to 20 MW boiler and systems are expected to lie in the range \$1.6m to \$9.2m installed with a midsize 10 MW unit at around \$5.4M. The specific cost is given by the following equation:

$$\text{Cost (Current)(\$/kW)} = 969 \times MW^{-0.25}.$$
$$\text{Cost (2012/2025) (\$/kW)} = 733 \times MW^{-0.25}.$$

Operations and maintenance costs are also thought to be higher than previous estimates. Whereas these had been estimated at around 2% of capital cost (MOC 1993), these are now thought to be closer to 5% of capital cost.

Fuel preparation by wood fuel companies such as CHH Biogrid could allow savings in fuel handling costs at the plant, but would come at a price while giving increased confidence for uptake.

Electricity Generation

As outlined above, electricity generation would frequently be by cogeneration. Dedicated plant would yield a higher cost.

Costs for electricity generation were assessed in the EECA 2001 report, based on simple combustion technology. The input values have been reviewed and compared with other estimates.

The new capital estimate has been influenced by detailed review of a range of budget prices and by the strong agreement between EPRI (1997) estimates and European estimates (Dornburg and Faaij 2001).

Table BMW8: Comparison of Efficiency and Specific Capital Costs for Combustion (Grate Firing) (\$/kWgr)[1]

Size (MWe)	Efficiency[2]	MOC 1993	EECA 2001	Current Report[3]
1	0.212	-	-	11,300
5	0.251	-	3,800	6,900
10	0.270	3,000	3,300	5,600
20	0.291	-	2,900	4,600
30	0.303	-	2,700	4,000
50	0.320	-	-	3,500

1. All values have been corrected to September 2001 New Zealand dollars and expressed in gross terms.
2. Energy conversion efficiency is based on figures by Dornburg and Faaij (2001). Efficiency can be approximated by the equation:

$$\text{Efficiency} = 0.2119 \times MW^{0.1055}$$

3. Costs can be approximated by the equation:

$$\text{Cost (Current) (\$/kW)} = 10{,}960 \times MW^{-0.2433}$$
$$\text{Cost (2012/2025) (\$/kW)} = 8{,}290 \times MW^{-0.2433}$$

The following table makes a comparison between the emerging gasification processes. Gasification's advantage comes from higher efficiencies, and will come from capital cost advantage as the technology matures. The forecast price reduction is based on projections by EPRI for the pressurised gasification process. Similar projections have been found elsewhere that implies an annual price reduction of 1.5%. This reduction has been applied to both gasification technology types.

Table BMW9: Comparison of Efficiency and Specific Capital Costs for Emerging Gasification Types ($/kWgr)[1]

	Pressurised BIGCC				Atmospheric BIGCC			
Size (MWe)	Efficiency[2]	Current[3]	2012	2025	Efficiency[4]	Current[5]	2012	2025
5	0.436	11,200	9,100	7,400	0.337	7,700	5,600	4,600
10	0.440	8,500	7,000	5,800	0.359	6,400	4,700	3,900
20	0.445	6,400	5,500	4,500	0.383	5,300	4,000	3,300
40	0.450	4,800	4,300	3,500	0.408	4,400	3,400	2,800
60	0.453	4,100	3,700	3,000	0.424	4,000	3,100	2,500
80	0.455	3,700	3,300	2,700	0.435	3,700	2,900	2,300

1. All values have been corrected to September 2001 New Zealand dollars and expressed in gross terms.
2. Efficiency of Pressurised Biomass Integrated Gasification Combined Cycle (BIGCC) technology is based on figures by Dornburg and Faaij (2001). Efficiency can be approximated by the equation:
   $$\text{Efficiency} = 0.4245 \times MW^{0.016}$$
3. Costs can be approximated by the equation:
   $$\text{Cost (Current) (\$/kW)} = 21{,}500 \times MW^{-0.3635}$$
4. Cost (2012/2025) ($/kW) =16,270 x MW $^{-0.3635}$ Efficiency of Atmospheric BIGCC technology is also based on Dornburg and Faaij (2001).
   $$\text{Efficiency} = 0.2905 \times MW^{0.0922}$$
5. Costs can be approximated by the equation:
   $$\text{Cost (Current) (\$/kW)} = 11{,}835 \times MW^{-0.2673}$$
   $$\text{Cost (2012/2025) (\$/kW)} = 10{,}175 \times MW^{-0.2673}$$

A comparison between O&M estimates for combustion plant based on American (EPRI 1997), Australian (SEDA 1999) and European (Dornburg and Faaij 2001) calculation schemes converted to current New Zealand conditions indicates O&M costs can be approximated by an annual allowance of 4% of capital cost for all technologies.

3.2 SENSITIVITY

Costs are highly sensitive to resource cost, the commercial sale of which is largely conjecture. There is a degree of uncertainty in capital costs and plant efficiencies with wide ranges in the literature.

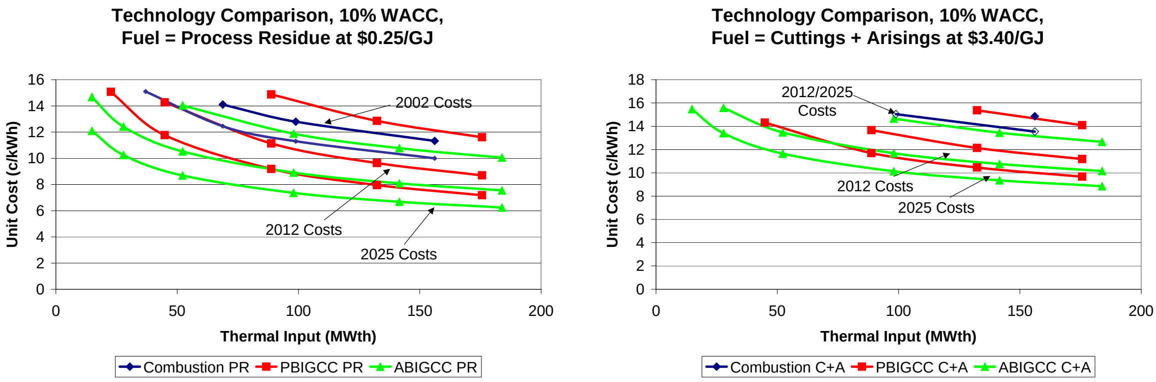
3.3 COST ESTIMATES IN THE FUTURE (2012, 2025)

These have been discussed in sections 3.1. Note that gasification costs are forecast to drop by about 1.5% per annum. The cost forecasts also take account of the forecast exchange rate change.

3.4 ESTIMATED OVERALL COSTS

Unit costs are shown in the figures below. Comparing the two biomass IGCC options, it can be seen that for thermal input less than 100 MWth, atmospheric pressure options are preferable to pressurised gasification plant. With the possible exception of the Central North Island, there is unlikely to be adequate resource in any region to feed units much larger than 100 MWth. Consequently, New Zealand applications of generation via gasification is likely to be limited to atmospheric BIGCC technology.

Figure BMW2: Comparison of Combustion with Gasification



When the cost of combustion plant is compared with gasification plant on a thermal input basis, it appears that gasification is on the verge of being economic, particularly for higher cost fuel applications. With a 35% decrease in unit cost over the next 24 years, gasification may become the dominant means of generation, assuming commercialisation takes its expected course.

Note that the discussion above assumes that the biomass resource will be developed for electricity. Actual uptake will be price dependent (a strong function of the integrated cost supply curves for all resources and technologies). For the prices indicated here, strong uptake is not expected until late in the period covered by the report.

3.5 NATIONAL SUPPLY CURVE DATA

The results of modelling the scenario given in section 2.7 is summarised below. Electricity and heat have been treated separately. Conceivably energy directed to heat could be redirected to electricity and vice versa.

Table BMW10: Electricity Generation Potential

Supply Cost Data	c/kWh	Year 2012		Year 2025	
		GWh/y		GWh/y	
		WACC=5%	WACC=10%	WACC=5%	WACC=10%
High Confidence	6-8	140	-	285	-
	8-10	-	-	-	-
	10-12	-	140	-	285
	12-14	-	-	-	-
	14-16	-	-	-	-
Medium Confidence	6-8	425	-	565	-
	8-10	1,130	285	1,345	285
	10-12	-	425	-	565
	12-14	-	705	-	1,060
	14-16	-	-	-	-
Low Confidence	6-8	4,245	-	4,665	-
	8-10	2,120	2,405	2,760	2,405
	10-12	635	2,265	990	2,545
	12-14	-	2,120	-	2,475
	14-16	-	635	-	990

Table BMW11: Heat Supply Potential

Supply Cost Data	$/GJ	Year 2012		Year 2025	
		PJ/y		PJ/y	
		WACC=5%	WACC=10%	WACC=5%	WACC=10%
High Confidence	2-4	-	-	0.5	-
	4-6	3.2	1.5	5.7	3.3
	6-8	-	1.7	-	2.9
	8-10	-	-	-	-
Medium Confidence	2-4	-	-	0.5	-
	4-6	3.2	1.5	5.7	3.3
	6-8	-	1.7	-	2.9
	8-10	-	-	-	-
Low Confidence	2-4	-	-	0.5	-
	4-6	3.2	1.5	5.7	3.3
	6-8	-	1.7	-	2.9
	8-10	-	-	-	-

4. FURTHER RESEARCH AND OTHER ISSUES

One of the greatest needs now is for dissemination of information. The research being lead by *ForestResearch* and by Massey University needs to be put in the hands of potential developers. These parties will continue to monitor and promote the industry. In particular, there will have to be a watching brief kept on the commercialisation of gasification on a large scale. A key vehicle for these actions is through the newly established Bioenergy Association of New Zealand.

Fuel quality issues must be researched with efforts directed at a reliable high quality fuel to sell into the new markets.

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CHAPTER 5 – BIOMASS (LANDFILL GAS)

1. TECHNOLOGICAL INFORMATION

1.1 ENERGY RESOURCES

Mixed municipal solid waste (MSW) consists of refuse from households and commercial premises, processing and industrial wastes, and material from demolition and construction. Typically around 60% to 70% of this material is organic in nature; mostly paper but also wood, garden wastes and food scraps. In New Zealand, landfilling is the dominant method of MSW disposal, with about 2.46 kg/person/day being generated (MfE:2001).

A typical landfill gas mix will range from 40:60 to 60:40 methane to carbon dioxide. In theory yields of 150-200m^3 of gas/tonne of wastes collected should be achievable, the gas mixture having a heat value of 19-22 MJ/m^3 (Baines 1993). In practice, over the lifetime of the site, the yields are a lot less than this.

Rate of decomposition can be accelerated by high temperature and moisture and presence of bacteria (say from inclusion of sewage sludge).

1.2 SYSTEMS ELEMENTS

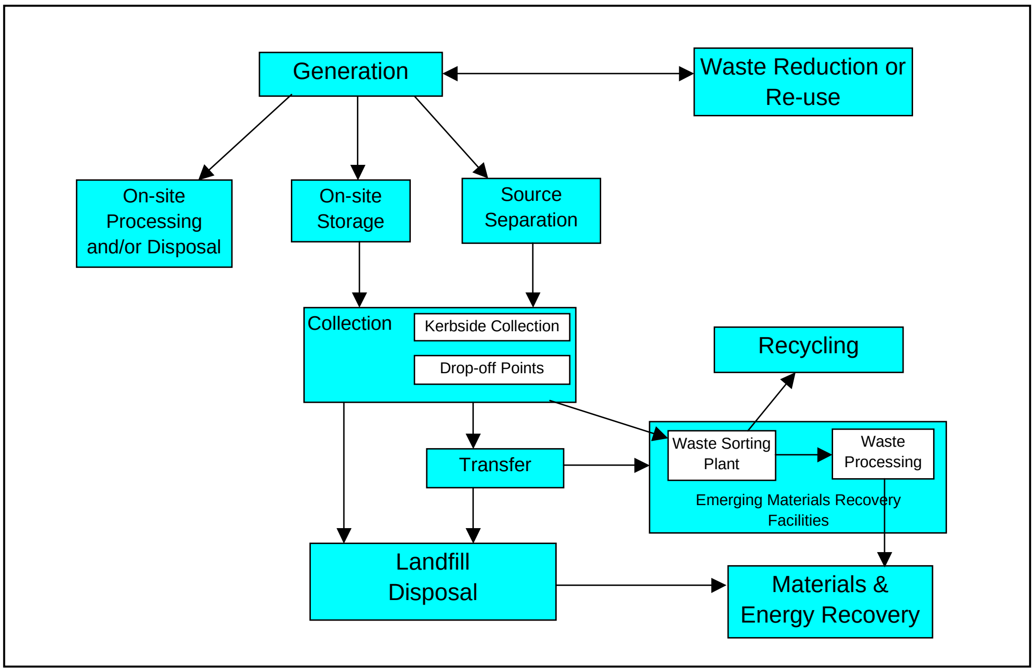
Landfill Management

Availability of large areas of land near major cities means that land filling will remain a part of New Zealand's waste disposal scene.

Landfill gas is an adventitious fuel that is a by-product of current landfilling practices. It is an extremely low efficiency way of recovering energy from MSW. In the long run, as the use of landfills necessarily dwindle, landfill gas will also decline as a resource (EECA/CAE 1996).

The current status of the MSW collection and processing industrial chains in the main urban centres in New Zealand is presented in Figure BML1. These chains are in a state of transition from the left of the diagram, and towards the right. At present, over most of the country there is only marginal on-site processing and source separation, limited recycling, and even less materials recovery, with no energy recovery prior to landfilling. In Auckland, and to a lesser extent Wellington and Christchurch, there is a commercial recycling and materials recovery industry that is emerging from the collection and sorting of traditional paper, glass, metals, and more recently plastics. This budding industry, however, encompasses only a small fraction of the overall MSW stream (EECA/CAE 1996). Several local government groups are considering "zero waste" implementation. Efforts towards recovery/recycling are being promoted and facilitated by groups such as BusinessCare National Trust.

Figure BML1: The Changing Waste Collection and Processing Chain (EECA/CAE 1996)



Overseas, although the situation varies enormously, there is a general and accelerating trend away from landfilling and simple recycling, towards fractionation, and materials and energy recovery through what is increasingly called materials recovery facilities (MRFs).

In recent years, there has been a trend to close smaller landfills, to establish transfer stations and to focus landfill management at a limited number of larger sites. Landfill gas collection is now a standard feature of large centralised landfill management. Steps can be taken to enhance both the production and interception of methane, and the resulting modified landfill is often referred to as a biofill.

Going further, the feedstock can be carefully selected and the decomposition be managed in a sealed structure or digester. All of the methane produced is captured. Certain types of wastes may be incinerated to aid the digestion process. MSW can be burnt as a fuel in its own right. The fuel value can be increased by sorting the waste or selecting certain types (such as wastepaper) for combustion.

In a conventional landfill, the bottom surface is sealed with an impermeable clay layer and leachate drainage is installed. Toxic wastes, if buried at the site at all are usually placed in a specially constructed zone. Otherwise there is little attempt to segregate the incoming MSW. The landfill is usually built up in layers covered with clean fill, or demolition material. When completed the landfill surface is usually sealed. Leachate is diverted into sewers for treatment. In some cases it is reinjected into the landfill.

The main changes with a biofill approach are site selection aiming for a high volume to surface area ratio and impermeable boundaries, steps to manage the in-situ moisture content so as to optimise methane production, the reinjection of leachate and possibly waste fertilisation (e.g. co-disposal of sewage sludge to enhance anaerobic microbial activity), segregation of organic rich wastes into high production zones, and the laying of gas drainage as the landfill progresses (MOC 1993).

Gas Extraction Systems

Landfill gas can be actively or passively extracted. Active extraction is used where odour prevention is an issue, and where commercial utilisation is desired.

Extraction systems are also characterised by the type of drainage wells used. In a conventional landfill, drainage wells are usually retrofitted and consist of vertical boreholes. In some cases a series of horizontal wells may be placed on top of the landfill between impermeable layers.

When high collection efficiencies are desired, an impermeable membrane can be placed over the landfill surface. While this can lead to savings in terms of pipe laying costs, there are new complications in terms of slip planes, surfaces above and below the layer, tree planting and surface drainage (Stewart 1996).

Collection efficiency of vertical wells can be 65%, while horizontal wells can achieve 75% but risk drawing in a large proportion of air. Extraction rates must be adjusted to minimise air entrainment.

Gas Treatment and Utilisation

Landfill gas usually contains significant amounts of moisture which must be drained and possibly reinjected prior to gas utilisation.

Landfill gas contains significant amounts of carbon dioxide and varying amounts of other gases that may have implications for its end use; hydrogen, acidic compounds like hydrogen sulphide, and trace components that may be toxic, carcinogenic and flammable, such as vinyl chloride and benzene. Various forms of treatment are available to make the gas suitable for its end use at a cost.

The carbon dioxide content of the gas can be accommodated by some uses, such as boiler fuel, because combustion conditions can be tuned accordingly. For some purposes, such as CNG for vehicles, the carbon dioxide content will need to be reduced. Acidic compounds, like hydrogen sulphide, may also need to be removed to prevent corrosion of piping and storage vessels. Carbon dioxide and hydrogen sulphide can be removed in a combined scrubbing operation. The residual moisture content of the gas may need to be managed within a set limit.

Treated landfill gas is used as input fuel for a wide variety of plant. For electricity production alone the options include boilers and steam turbine sets, reciprocating engines, gas turbines and combined cycle arrangements. While plant may be tuned for landfill gas it will be similar in design and operation to normal natural gas equipment.

1.3 SYSTEMS AND APPLICATIONS

Conventional landfills, retrofitted with extraction wells, and biofills managed to enhance gas production and extraction, are the two main systems for dealing with relatively unsegregated MSW.

International experience indicates that landfill gas is also used to augment reticulated gas supplies, to provide CNG for vehicles, to treat effluents, and to provide a fuel for cement manufacture and metal refining. The main factor affecting its end-use is the proximity of a heat demand to the landfill site and the relative cost of producing and transmitting electricity from the site. Gas has been transmitted several kilometres from some sites but the need for pipelines eats into the economics of supply.

Landfill sizes and their total gas yields vary enormously and this is reflected in the installed capacity of electrical plant, boilers or kilns based on this energy resource. Electrical power outputs typically range from 1 MW to 50 MW. In New Zealand they are at the lowest end of the range. Individual generators are typically about 1 MW in size (MOC 1993).

1.4 TECHNICAL STATUS

The technology required to extract landfill gas, treat and utilise it to produce heat or power has been commercially applied since the 1970s. Ability to accurately predict the rate of gas supply, its variability and duration from existing landfills is still being developed. Similarly models to predict the performance of biofills are still being refined. The state of knowledge in both these cases is not mature. Improved understanding requires further empirical information gained through experience and a cross match with theoretic models (MOC 1993).

1.5 APPLICATION LIMITS AND SYNERGIES

Landfills need to be of a certain size to hold the promise of enough gas resource to make the costs of investigation and investment worthwhile. Gas supply can show short-term variation due to changes in production and infiltration from different zones, temporary pipe blockages, etc. Coverage can be an important issue to avoid excessive air infiltration. This variability in gas yield can limit the type of uses adopted.

On very large landfill sites being developed in stages, continuity of supply may extend over many decades as different areas are brought into production. On the other hand the gas supply lifetime of an existing landfill could be limited to only a few years, depending on the age of the site, the amount of gas that has already escaped, etc. This latter situation will generally require any investment to have a short payback period.

New Zealand is undertaking some research on the ability of geothermal fluids/conditions to accelerate biodegradation (Heveldt 1999). While research has focused on use of high temperature resources, a real opportunity may exist at Whitford south of Auckland.

The main synergy is between landfill gas utilisation and environmental controls. Concern over the odour control, public safety and especially methane emissions means that increasingly gas drainage systems would be needed anyway. Making use of the gas, instead of flaring, is often a cost effective next step.

1.6 CRITICAL FACTORS

The critical factors affecting the viability of a landfill gas project relate to gas supply and demand. A secondary factor is the ability to manage the supply by reducing losses and enhancing production.

A nearby demand for heat (typically less than 1 km) or the ability to attract an industry to the site, close proximity to a gas or electricity reticulation network, and a relative cost advantage over other fuels and electricity sources will make investment in gas extraction and treatment attractive.

Another key issue for landfill gas is future strategies for waste management. Trends towards paper recycling, composting other organic material (or mulching yard wastes), may mean that future landfills will not be high producers of methane gas. This would affect their viability as potential renewable energy sources (MOC 1993).

1.7 ENVIRONMENTAL ISSUES

Decomposition of refuse in landfills produces landfill gas which typically contains about 55% methane and 45% carbon dioxide. Landfills in New Zealand are estimated to generate about 240 million m^3 of landfill gas each year. Because methane has a Global Warming Potential 21 times that of carbon dioxide, the landfill gas has a greenhouse gas equivalent of 5.65 million tonnes of carbon dioxide (Stewart 1996).

Managing a landfill to minimise methane production, while collecting and using the landfill gas that is produced, can produce a greenhouse benefit. Net storage of about 140 kg of carbon equivalent per tonne of wet refuse can result. On the other hand, optimising methane production, using a biofill approach, can lead to net emissions of around 130 kg of carbon equivalent. While with a biofill more gas is produced and utilised, more may also escape to the atmosphere where it adds to global warming risk. Furthermore, with biofills there is less long-term carbon storage in the ground. This difference may affect the future economics.

Other environmental issues include odour, risk of asphyxiation, vegetation damage, fire risk, and concerns related to flaring (including noise).

Possibly the best place to try to enhance anaerobic production of methane is in digesters where 100% of the methane can be collected.

2. NEW ZEALAND RESOURCE INFORMATION

2.1 INFORMATION SOURCES

References are given at the back of this section. Advice was obtained from the Ministry for the Environment. EECA have assisted through their articles on successful projects such as Redvale.

2.2 THE LOCATION OF RESOURCES

Landfills are located throughout New Zealand and are naturally focussed on population centres.

2.3 THE QUANTITY OF THE RESOURCE

There are no reliable estimates of the utilisable landfill gas resource in New Zealand. Previous estimates have been low.

Approximate estimates have been developed by Ministry for the Environment using S.G.S. Wetherill to assess methane emissions from landfills. Based on a population of 3.8 million people, about 3.5×10^6 tonnes of waste is expected to be landfilled annually. Assuming about 16% of waste is organic, 50% of waste degrades and 50% of the carbon is released as methane implies gross methane production of 174×10^3 tonnes (MfE pers. comms). Pure methane has a net calorific value of 50 MJ/kg (Baines 1993), so total resource is approximately 9 PJ.

The potential total gas volume of 9 PJ/year is mostly difficult to recover as many landfills are too small to warrant landfill gas extraction. The gas volumes are also reduced on poorly designed sites where leachate loss occurs. Where feasible, collection of landfill gas should be encouraged and conversion to heat and electricity undertaken as the resulting conversion of CH_4 to CO_2 will lower the climate change impact.

2.4 VARIABILITY OF SUPPLY

There are large uncertainties in the quality and quantity of landfill gas. With a likelihood of further sorting, reuse, composting, etc. in future the resource may be expected to diminish. At the same time, use made of large well-managed landfills could increase the utilisable gas available.

2.5 CURRENT UTILISATION OF RESOURCES

Wetherill assessed that 44 x 10^6 tonnes (2 PJ) of methane from landfills is currently recovered, but most of this is flared (MfE pers. comms).

Several sites have been producing gas in Auckland (three), Hutt Valley, Porirua, and Green Island, Dunedin. Gas collection efficiencies are in the range of 50% to 60% for most of these landfills, and the conversion efficiency of the gas engines gives an overall efficiency around 18% (van der Voorn, 1996). Future sites could use membrane collection systems to increase the collection efficiency to 90% and cogeneration systems of 80% to give an overall output efficiency of 72% if a use for the heat can be found nearby (EECA/CAE 1996).

The purification level for the gas depends on its utilisation. At Green Island it was scrubbed (washed with water under pressure to remove CO_2) and the 97% CH_4 was then blended with air to given the optimum gas blend for pipeline reticulation. Unfortunately this project had difficulties in managing air entrainment. More recently, the scheme has been largely superseded through reticulation of gas from shipped LPG supplies.

Gas was also reticulated from the Porirua site but this has also shut down in recent months.

Management of a site to maximise gas yield is only possible when starting a new landfill site rather than if drilling into established landfills. Recycling of the leachate effluent is important to maximise gas output and avoid groundwater pollution.

Auckland has three successful electricity generation projects. Older projects at Rosedale and Greenmount use landfill gas in reciprocating engines. (The Silverstream Landfill gas project in the Hutt Valley is similar.) The latest award-winning project is the Redvale Landfill gas project. This, like Rosedale, is located in the electricity constrained North Shore area at Dairy Flat and is operated by Waste Management New Zealand Limited. It produces 8.4 GWh/year from a 1 MW generator. More than 90% of this is sold and distributed locally. Some methane gas is burnt to evaporate the landfill leachate rather than trucking it to disposal sites elsewhere. There are plans to commission a further 1 MW generator in December.

The Redvale plant is the first in the world to automatically disconnect and reconnect to the local grid. The generator plant cost $1.4m to construct and reduces CO_2 emissions by 77,000 tonnes each year. The leachate evaporator (also costing $1.4m) has operated since August 1999. It vaporises the leachate, then incinerates this at high temperature to minimise air pollution. It is the first in the Southern

Hemisphere to use landfill gas rather than natural gas to achieve this and has an 80,000 litre/day capacity. By using landfill gas it saves purchasing around 200 TJ of natural gas a year. Expected lifespan is 20 years.

The waste pile produces 2,500m^3 of gas/h (at an NCV of around 19 MJ/m^3). 600m^3/h is required to keep a stable flame for the flare.

The engine is specifically designed to run on gas and can burn gas with a methane content down to 28%. This allows aggressive capture of gas with a capture efficiency approaching 90%.

Current generation:	Rosedale	21 GWh/year
	Greenmount	31 GWh/year
	Redvale	8 GWh/year
	Silverstream	14 GWh/year
		74 GWh/year

(Further units were installed at the Whitford landfill (also in Auckland) at the time this report was being finalised).

2.6 INFRASTRUCTURE OBSTACLES

There are no known obstacles other than remoteness of sites from loads and the subsequent need for installation of transmission lines. Thus, although there is a potential to use landfill gas for heating, there is a trend away from this.

2.7 VIEW ON UPTAKE

Utilisation is possible from large, well-managed landfills. These will be possible in the vicinity of major cities. The New Zealand Official Yearbook 2000 indicates in 1999, 2.15 million people out of a national population of 3.8 million live in the major cities. Given that the smallest of these cities (including Upper Hutt and Porirua) already have successful utilisation projects, and there is continuing urban drift, then 50-60% of the population will have access to major landfills.

Allowing for some inefficiency in collection (10-40%) and flaring (2 PJ based on 20 sites requiring an average 600 m^3/hr of 18.8 MJ/m^3 gas for flaring) implies a utilisable resource of 1.2-2.7 PJ. A small portion of this may be used for heating but most could be converted to electricity with an efficiency approaching 36%. Therefore, maximum generation is likely to be 0.42-0.97 PJ (110-270 GWh/year) per year. A previous forecast was for a 150 GWh/year potential resource (MOC 1993).

Subtracting off current generation at 74 GWh/y implies a potential for new generation of around 40 to 200 GWh/y. The highest estimate will apply when landfills have high collection efficiencies. In the near future the raw materials for landfills will decrease. The net effect is that the total capacity is unlikely to exceed a further 100 GWh/y.

Given that collection is already taking place at Porirua and Green Island, generation from these sites would appear feasible in the short term. A preliminary assessment for Porirua indicates little potential beyond requirements for flaring (based on a population of 50,000). Green Island could generate around 1.4 MW/10 GWh (based on a population of 120,000). There are stated plans to generate a further 1MW/8GWh from Redvale.

In total, this forecasts a total landfill gas generation of 174GWh from our current 3.8 million population base. This is about half of the pro-rated projection for Australia by 2010 (Redding 1999), but is partly a reflection of the limited number of very large landfills.

3. ENERGY SUPPLY COSTS

3.1 CAPITAL AND OPERATING COSTS

Gas collected from landfills can be used to generate electricity in a variety of ways such as gas turbines, boiler and steam turbines, and gas engines. Because of the size of New Zealand landfills gas engines have lead to the least cost power production.

There is growing experience with developing landfill gas energy resources in New Zealand. The cost and performance data for some New Zealand projects are shown in Table BML1 below.

Table BML1: Cost and Performance - Data Three New Zealand Landfill Sites

Performance Parameter		Rosedale		Greenmount		Redvale		Typical	
Capital Cost Generation $m		(5.40)[1]		(9.60)[1]		1.4		1.5	
Capital Cost Collection $m		(2.20)[1]		(4.75)[1]		0.7[2]		0.75	
O&M Cost c/kWh[3]		1		1		1?		1	
Power Output MW		3.5		5.2		1		1	
Capacity Factor %		85		85		95		90	
Power Output GWh/yr		26.1		38.7		8.4		7.9	
Net Output GWh/yr[4]		21.0		31.0		7.6		7.1	
Project Life yrs		15		15		15		15	
Lifecycle Power Cost c/kWh	WACC	5%	10%	5%	10%	5%	10%	5%	10%
	Incl. Collection	5.1	6.9	6.2	8.5	4.2	5.6	4.6	6.2
	Excl. Collection	3.9	5.2	4.5	6.0	3.1	4.0	3.4	4.4

1. Costs have been converted to 2002 costs.
2. Cost excludes additional cost of leachate treatment ($1.4m). Cost has been halved as collection system has been designed for a second generator.
3. O&M costs are effectively fixed. This could be re-expressed as $70/kW/year.
4. Power exported net of own use.

The total capital costs work out at around $2,250/kW. Assuming that gas collection and flaring become a compulsory feature of landfills because of the major environmental impact of methane emission, then the capital cost of generating plant only is around $1,500/kW.

There are landfill sites like Porirua and Green Island where gas collection is currently in place allowing generating plant to be installed for the minimum cost.

3.2 SENSITIVITY

The greatest uncertainty lies in the cost and effectiveness of the gas collection facility (but even this shows remarkable similarity across the physical projects above in terms of proportion of capital costs). Where this cost is netted off there can be high confidence in the capital cost. Plant availability may be in doubt due to long-term resource availability.

3.3 COST ESTIMATES IN THE FUTURE (2012, 2025)

No major technological breakthroughs are expected in the hardware used to collect and generate power from landfill gas. Other forecasts suggest steady costs into the future. Two critical factors affecting the economics of landfill gas based power schemes are the gas yield per tonne of waste and the total available gas resource. Both of these can be affected by future waste management strategies and affect collection costs. Trends towards paper recycling, composting, the mulching and reuse of yard wastes, etc. may reduce landfill gas production and increase the costs of electricity generation, if the cost of collection is included in the power generation costs.

On the other hand, a variety of landfill management options are available to enhance production or collection of gas. Adopting these could counter trends that might reduce the supply of organic material to landfills. It is impossible to sort out whether the net result is an increase, decrease or no change in future costs and resources. The Redvale project, for instance, has a collection cost equal to generation cost.

Taking the view that collection cost will be an essential feature of any landfill and should be written off as an environmental control feature, then steady costs are expected for the generation equipment.

The exchange rate change from US$0.42=NZ$1 to US$0.5=NZ$1 will reduce the capital cost by 12.5%.

3.4 ESTIMATED OVERALL COSTS

Table BML1 above gives the overall costs. Where it is recognised that collection is a landfill cost, as opposed to a generation cost then landfill generation costs are attractive now. Where advantage may be taken of embedding, then full collection costs may be able to be accommodated also.

3.5 NATIONAL SUPPLY CURVE DATA

Working out how much power could be generated from landfill gas at various costs would require an integration of information on resource availability at various sized landfill sites with appropriate development costs. The former data is not available.

There is immediate opportunity for 10 GWh from Green Island and a further 8 GWh at Redvale, at the cost of generation plant only.

Beyond this a further 82 GWh is possible by 2012. No further capacity is expected beyond then.

Table BML2: Landfill Cost Supply Curve

Confidence Levels	c/kWh	Year 2012 GWh/y		Year 2025 GWh/y	
		WACC=5%	WACC=10%	WACC=5%	WACC=10%
High Confidence	2-4	18	8	18	8
	4-6	82	18	82	18
	6-8	-	74	-	74
Medium Confidence[1]	2-4	100	-	100	-
	4-6	-	100	-	100
	6-8	-	-	-	-
Low Confidence[1]	2-4	100	-	100	-
	4-6	-	100	-	100
	6-8	-	-	-	-

1. Medium and low confidence level resources are not additional to the high confidence level resources but represent the opportunity if collection costs are netted off the total capital cost.

4. FURTHER RESEARCH AND OTHER ISSUES

Research related to methane generation in landfills fall into three broad classes:

1. Landfill Surveys and Site Assessment of Landfill Gas Quantities
2. Methods to Reduce or Control Methane Production and Migration
3. Methods to Enhance Methane Production in Landfills

The first type of research can be broken into two categories. The first is national surveys aimed at providing landfill inventories and rough estimates of the economic energy development potential. This work is supply curve related. In the New Zealand context landfill gas has only a small potential as a renewable resource, albeit a cost effective one in some cases. Work could be done to obtain more reliable estimates of the energy potential of landfill gas in this country, but the nature of the resource will limit the level of confidence that can be achieved.

This leads to the second type of resource survey, the site-specific landfill gas resource estimation. To obtain reliable national supply curve data specific site surveys would need to be conducted at a similar level of detail to that needed to prove the resource for development.

New Zealand technologists should continue to monitor international research. The most immediate need in this country though is to gain experience with landfill gas resource survey, energy development and gas collection and use system management. Developing more cost effective and reliable site testing and monitoring procedures may facilitate a greater level of resource development.

There is benefit in publishing case studies to provide customer and developer confidence in the resource.

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CHAPTER 6 – BIOMASS (OTHER)

1. TECHNOLOGICAL INFORMATION

1.1 ENERGY RESOURCES

Previous sections have covered woody biomass and landfill gas resources. Other potential energy sources include:

- Agricultural residues or dedicated crops (e.g. corn, oats, kale, and possibly sugar beet)
- Alternative treatment of Municipal Solid Waste
- Sewage and waste water treatment schemes
- Animal effluents
- Other waste product streams.

These can be burnt, gasified or treated to produce biogas.

Biogas is commonly produced by anaerobic digestion as part of the treatment of wet waste and utilisation of a resource. This occurs in municipal wastewater and sewage treatment plants, industrial operations that have liquid wastes containing organic material and on types of farms where animals are kept or held in a small area, such as pig or poultry farms.

In many cases treatment of the waste to produce biogas is not economical but is carried out for other reasons such as waste management or reduction in greenhouse gas emission initiatives.

On the smaller scale generation of biogas is rarely economic because of the high labour requirements and dilute nature of the effluent being treated.

1.2 SYSTEM ELEMENTS

The energy resources can be handled by two broad types of systems: combustion/gasification systems, and anaerobic digestors.

Combustion/Gasification

Combustion and gasification have been discussed in detail in the chapter on woody biomass.

Anaerobic Digestion

Landfilling is a special case of anaerobic digestion. Anaerobic digestion is the decomposition of organic matter in the absence of air to produce biogas. The biogas is a mixture of mainly methane and carbon dioxide with very small amounts of hydrogen sulphide and other impurities.

The methane content can range from 50% to 80% (on a volumetric basis).

Biogas from the digestion of crop materials is typically 55% methane and from animal manures typically 65% methane.

Biogas from meat and poultry processing effluents and sewage plants tend to have higher levels of hydrogen sulphide (H_2S), up to 5%. Biogas with these amounts of H_2S may require further treatment before use.

The high amounts of carbon dioxide in biogas typically reduce the heating value to between 18 and 26 MJ/m^3 (GCV) compared with natural gas typically around 40 MJ/m^3 (GCV).

Unless biogas demand meets biogas production, storage may be needed or the biogas flared or vented.

Low pressure storage can be in gasometers or butyl rubber bags.

1.3 SYSTEMS AND APPLICATIONS

Combustion and gasification have been discussed in the chapter on woody biomass.

Gasification products (syngas) can be used in a number of different types of plant such as reciprocating gas engines, gas turbines (combined cycle) and fuel cells. Gasification can be used where crops are not readily suitable for direct combustion.

Biogas from anaerobic digestion can be used to produce heat for the digestion process itself, or process heat and electricity in other parts of the plant. It can also be upgraded to “natural gas” quality and fed into a local utility network.

1.4 TECHNICAL STATUS

Combustion

This is a mature technology.

Gasification

There are a number of gasifying technologies available and several plants have been built to demonstrate some of these.

Integrated gasification combined cycle (IGCC) plants have the potential ability to convert biomass to electricity more efficiently than combustion technologies using the steam cycle. Several biomass plants have been built but none are in commercial operation. (Most gasification plants have coal and petroleum [mainly heavy residues] as the predominant feedstocks for gasification projects.)

At present wood, charcoal, rice husks and coconut shells are generally considered suitable feedstocks for biomass gasification.

The most successful biomass gasification plant appears to have been at Varnamo in Sweden. This started up in 1996 and was mothballed in 2000 having achieved about 3500 hours of integrated operation.[1]

It appears that biomass fuelled IGCC will not be economically viable in the shorter term in plants smaller than 20 MWe.

[1] http.//exergy.se/goran/hig/ses/01/biomass

Anaerobic Digestion

Anaerobic digestion is a mature technology and is used worldwide, particularly for municipal waste water treatment. Here the scale of treatment can justify the costs of installing and operating the equipment needed.

1.5 APPLICATION LIMITS AND SYNERGIES

In some cases, on site combustion or open stockpiling would be environmentally unacceptable, in which case transportation to a centralised processing facility is required.

Stockpiling of feed material, except for short term buffering, is not normally practical. This is because the feedstock will degrade through natural processes and in some cases give rise to the conditions the process is trying to prevent, e.g. excessive odours from waste material.

Biogas from anaerobic digestion is essentially a continuous process so it requires a reliable continuous feed of material.

Waste effluent is generally very dilute so processing this is difficult and expensive.

The main synergy is between waste management and environmental controls.

1.6 CRITICAL FACTORS

Production of energy crops overseas has been assisted by the presence of “set aside” land and government subsidies of renewables. These have not been New Zealand practices.

Biogas generation is sensitive to the similar critical factors to those outlined in the biomass section.

Excess moisture may cause handling problems for gasification processes.

If the organic content of wet waste stream is too dilute, recovery of the energy content will be made more expensive.

1.7 ENVIRONMENTAL ISSUES

Some of the environmental issues have been discussed in the previous chapters on woody biomass and landfills.

There are significant environmental benefits from waste digestion. These include reduced impacts of the effluents and solid waste disposal. Sludge from the digesters can be returned to the soil as fertiliser.

Production, collection and use of biogas reduce methane emissions to the atmosphere. Methane as a greenhouse gas has 21 more times greater effect than carbon dioxide. Hence, using biogas from a sustainable source is nearly carbon neutral. The energy from biogas will replace energy from other sources which may have come from non-renewable fossil based sources.

Processing solid waste through a gasifier reduces the bulk of material going to landfill sites, controls use of carbon based material in the waste, and reduces hazardous materials going to waste sites.

2. NEW ZEALAND RESOURCE INFORMATION

2.1 INFORMATION SOURCES

The 1993 Ministry of Commerce Report and the 1996 EECA/CAE Report formed the basis for this section.

2.2 THE LOCATION OF RESOURCES

Agricultural Residues and Crops

There is no “set aside” land in New Zealand, as there is in Europe due to excess production. As energy crops would need to yield an attractive return for the farmer, a delivered fuel cost in excess of $11/GJ will be required. This is immediately too expensive for heat applications and can be calculated to be too expensive for electricity generation. New Zealand land will be directed to other uses. Thus crops are not considered further in this report. However for a detailed discussion of crop options refer to the EECA/CAE Renewables Report (EECA/CAE 1996).

Agricultural residues will exist throughout New Zealand. They will be concentrated at centralised processing areas such as the Hawkes Bay. Comprehensive surveys of this resource are unknown. The resource can be attractive, with New Zealand’s oldest cogeneration plant fired by waste cereal husks being located in Gore (closed 2001 after successful operation for more than 60 years).

Municipal Solid Waste/Sewage Treatment/Waste Water Treatment

These facilities are located in all major centres in New Zealand.

Animal Effluents

New Zealand’s economy is dominated by farming. The majority of livestock are fenced as opposed to housed so effluent collection opportunities are limited. Intensive livestock industries include piggeries and poultry. There are secondary collection opportunities in the dairy industry during the time that cows occupy the milking sheds. Similarly, there are opportunities for collection from meat processing facilities.

Piggeries
There are nearly 370,000 pigs in New Zealand, 177,000 in the North Island v 192,000 in the South Island, spread over 4200 farms.

In the North Island about 55% of the pigs are on 48 farms, each with herds of 1,000 or more. These are mainly in the Waikato, Taranaki, and Manawatu-Wanganui regions. In the South Island herds with 1,000 or more pigs represent 52% of the pig population spread over 45 farms. Canterbury has the largest number of pigs, over 148,000 or 40% of New Zealand’s total.

Poultry
In the year ending 2000 just over 111,000 tonnes of poultry meat was produced of which 96% was broiler chickens. Three companies produce more than 90% of the broiler chickens in six processing plants. 80% of the waste is processed so the potential is around GWh/year of electricity. Large processing plants are situated in the Auckland, Waikato, Taranaki, Wellington, and Canterbury regions. There are 15 small processors serving local markets throughout New Zealand.

Dairy
Dairy farms are located nationwide. The Waikato and Taranaki account for half of the nations dairy stock, followed by Northland, Bay of Plenty, Manawatu-Wanganui, Canterbury and Southland.

Meat Industry
Effluent from the meat industry processing plants is treated and can be a source of biogas. Plants are located nationwide.

Other

Pulp and Paper mills have effluent streams with biodegradable material. Major mills are located in the Bay of Plenty, with other plants located at major centres shown in the woody biomass chapter.

The large dairy factories offer the opportunity for production of ethanol as a liquid fuel from whey. Factories are nationwide, though have been rationalised into fewer centralised sites.

The nationwide meat processing industry provides an opportunity for production of tallow as a potential biodiesel.

2.3 THE QUANTITY OF THE RESOURCE

Dairy Processing

The following biogas amounts may be collected from milking sheds, based on published herd sizes.

Table BMO1: Energy Potential from New Zealand Milking Shed Effluent.

Region	**Region Total**		
	cu m methane/day	**GJ/day**	**Annual GWh**
Northland	20,330	730	19.5
Auckland	6,990	250	6.7
Waikato	82,630	2,960	79.1
Bay of Plenty	18,910	680	18.1
Gisborne	270	10	0.3
Hawkes Bay	2,400	90	2.3
Taranaki	34,910	1,250	33.4
Manawatu-Wanganui	17,630	630	16.9
Wellington	5,430	200	5.2
Total North Island	**189,500**	**6,790**	**181.4**
Tasman	4,200	150	4.0
Marlborough	1,690	60	1.6
West Coast	6,700	240	6.4
Canterbury	15,420	550	14.8
Otago	6,810	240	6.5
Southland	12,460	450	11.9
Total South Island	**43,080**	**1,540**	**45.3**
TOTAL NEW ZEALAND	**232,580**	**8,330**	**226.8**

Whey is currently used in New Zealand as a source of ethanol. It is estimated that 40-50 million litres of ethanol could be produced in New Zealand from this source. Current production is about 12 million litres (PA Consultants 2001). This equates to 0.25 PJ/year.

Meat Industry

Effluent from all meat processing plants is treated. The potential for electricity from biogas is small, amounting to an estimated 40 GWh/year. Leather and skin processing plants would have the potential of a further 20 GWh/year.

Tallow production by the New Zealand meat industry is around 100,000t/y. After conversion to esters this equates to approximately 10% of the national transport diesel demand.

Piggeries

Methane generated from anaerobic digestion of the waste from the piggeries is estimated at 221 m^3/day or 211 MWh annually for a North Island piggery and 383 m^3/day, or for a South Island piggery equivalent to 367 MWh.

Potential methane resource generated from piggeries with more than 1000 pigs per farm is listed below.

Table BMO2: Energy Potential from New Zealand Piggery Effluent

Region	Cu m methane/day	Energy GJ/day	Electricity Potential GWh
Northland	130	4.6	0.12
Auckland	440	15.8	0.42
Waikato	3,900	139.8	3.74
Taranaki	960	34.5	0.92
Manawatu/Wanganui	1,040	37.4	1.00
Wellington	390	14.0	0.37
Marlborough	260	9.1	0.24
Canterbury	6,070	217.8	5.82
Otago	610	21.9	0.59
Total	**13,800**	**495.0**	**13.22**

Pulp and Paper

The potential for electricity generation from biogas is small, less than 40 GWh/year.

Commercial Wastewater and Sludge

The estimated annual biogas potential for New Zealand from commercial wastewater and sludge is about 160 TJ or 17 GWh of electricity.

Sewage

A recent study of wet waste resources in New South Wales concluded that methane generation is more appropriate for larger sewage treatment plants (STP) located in metropolitan coastal areas.

In small STP the cost of installing gas collection and energy recovery equipment cannot be justified economically.

For an equivalent population of 14,000 the annual electricity potential from methane generated by sludge digestion is just 0.27 GWh.

2.4 CURRENT UTILISATION OF RESOURCES

In the 1970's ethanol production from a range of crops, including wood was investigated and trialled. Although pilot plants were built no commercial activity resulted due to the drop in the crude oil price.

Ethanol from dairy feedstocks is a mature technology. Three plants exist representing both batch and continuous fermentation technology. The ethanol is used as a solvent or as a beverage additive. As an energy source, ethanol via dairy products is a very efficient energy conversion route. Other than using the limited quantity of waste product whey, it would not be a practical proposition to produce dairy products as an energy source (EECA/CAE 1996). Current production of ethanol from whey is 12 million litres per year (equivalent to 0.25 PJ/year).

Sewage treatment plants have been methane generators for decades, the gas being used on site to produce electricity for local consumption or export from the site in rare cases. Plants at Christchurch and Auckland are good examples. There has been a recent trend to use both methane and natural gas supplies in generators. Auckland has both energy sources on site while Hamilton premixes gas before being fed into a second hand reciprocating engine.

On-farm digesters producing biogas have been installed on a number of farms to use animal wastes and green crops as feedstocks. At a small scale considerable dedication is required to meet the high labour demand. Many small scale plants have closed down in recent years, but large scale plants continue to operate successfully. A Wairarapa piggery has a facility including solids separation, some irrigation to pasture, hot water production, manure to land, a digester, butanol storage bag for the gas and 190 kVA engine/generator for electricity generation (about half the farms requirements). The economics are dubious unless the benefits of offsetting the costs of waste disposal are taken into account. The New Zealand Standards Association produced a code of practice which remains a useful set of guidelines (EECA/CAE 1996).

On a larger scale several food processing plants, such as Cedenco Ltd in Gisborne, have installed an anaerobic digester to deal with the waste product. At this scale, as for city sewage plants, it is feasible to employ specialists to operate and maintain the plant. Recent developments and experience in treating a wide range of waste products including MSW, toxic wastes, high protein wastes, high lipids wastes and cellulosic wastes have led to reductions in plant capital and operating costs.

An extensive research and development programme funded largely by the Liquid Fuels Trust Board and concentrating on tallow esters and rapeseed oil, was successfully completed in 1987, but not taken forward. It included fleet trials of a wide range of vehicles operating on 10% blend of esters with diesel (EECA/CAE 1996).

2.5 VIEW ON UPTAKE

Production of bioethanol from whey is likely to accelerate, but its overall contribution will be insignificant in terms of contribution to the New Zealand energy mix (less than 0.5% of transport energy).

Currently the production of biogas is a by-product of waste management processes. The production of heat and/or electricity using that resource can at the same time reduce methane emissions.

The energy content of waste is low and the resource thinly spread with a total potential supply of 350GWh/year based on the totals in section 2.3 (excluding domestic sewage treatment). Economic processing of the waste into biogas is feasible only in processes that have volume and concentration. There must also be a heat and/or electricity use for the biogas produced. These conditions are uncommon in New Zealand.

Production of electricity from sewage plants has proved economic, but it is assumed that the economically available resources have already been taken up.

With energy prices at current levels the production of heat and electricity from biogas is seldom economic. Increased uptake (apart from some natural growth due to population) is not likely unless there are other factors to provide an incentive.

Climate change legislation will likely increase uptake of anaerobic digestion of wet wastes to reduce greenhouse gas emissions. However, the effect in overall energy terms is likely to be very small.

Long term, however, depending on local conditions biomass energy will be competitive with heat and electricity generated from other sources. This uptake will be assisted by greater knowledge, awareness and acceptance of bioenergy systems.

There are 3,200 dairy farms in New Zealand with herds greater than 300 head. Assuming that 10% of the manure is collected from all these farms for half of the year, the potential electricity generation is 90 GWh/year. However, the cost of energy will be in the 20 to 30 c/kWh range. This may be an alternative to diesel for the individual farmer.

3. ENERGY SUPPLY COSTS

3.1 CAPITAL AND OPERATING COSTS

Costs for individual plant are very site specific, so these costs are ± 30%. They are also scale and technology dependant.

Preliminary estimates for dispersed digesters suggests electricity costs in the 20 to 30c/kWh range. These costs are outside the range of 15c/kWh set for this report so are assessed as making zero contribution. In fact, at this price these resources may be seen by farmers as attractive alternatives to some diesel generation. Digesters have not been studied in greater detail.

3.2 SENSITIVITY

Biogas production is particularly sensitive to feedstock costs. This is shown in the case of biogas crops where the return required to make a farmer switch makes biogas production not viable.

3.3 COST ESTIMATES IN THE FUTURE (2012, 2025)

New Zealand has leading edge developers of digesters and will have niche designs developed for this market. Production learning curves will see costs continue to decrease.

4. FURTHER RESEARCH AND OTHER ISSUES

New Zealand could gain advantage through:

- Ongoing research into digester and their inter-relation with alternative energy conversion technologies such as fuel cells and micro-turbines.
- Determining the extent of the current waste treatments using aerobic waste treatment that could be converted to anaerobic digestion.

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MAF Statistics.

CHAPTER 7 - SOLAR HEATING

1. TECHNOLOGICAL INFORMATION

1.1 ENERGY RESOURCES

Solar hot water is cost competitive relative to retail electricity tariffs throughout New Zealand and the maximum yearly output from this source is principally limited by public (home owners, builders, architects, and plumbers) perception on value of the investment. The number of systems that can be installed by either importer/suppliers or local manufacturers is adequate to match demand.

1.2 SYSTEM ELEMENTS

Solar heating can be grouped into low or high grade heat categories. Low grade heat (up to 120^{o}C) collection allows the highest efficiency of utilisation of the available resource but the most limited range of applications of the stored energy. Typical applications use the low temperature heat directly for space and water heating. At the other extreme, high grade heat collection (above 120^{o}C) has the greatest possibility of heat losses degrading performance, require more sophisticated collection technologies, but have the widest range of applications. Such applications include steam generation for driving engines and hot water sterilisation in factories.

This report only covers low grade heat as high grade heat is not currently economic.

This report also excludes passive building and space heating technologies, or solar thermal systems producing electricity. The project brief excluded technologies where the cost of production of electricity would not be within the 15c/kWh breakpoint within the time frame for the review.

The system for collecting solar energy consists of a solar panel, heat transfer system and a water storage cylinder. Installation of a solar system can either be with connection to existing cylinders or with installation of a matched solar cylinder.

There are two principal designs for a solar system:

(a) A thermosiphon system has a storage cylinder above the solar panel and hot water moves naturally from the panel to the cylinder. In these systems the hot water cylinder has to be either with the panel on the roof or located under the roof but within the roof structure. Some systems circulate a fluid such as glycol rather than water thus eliminating frost and poor quality water problems.

(b) The pumped system allows the cylinder to be located anywhere within or outside the building. An existing cylinder or a specially designed solar cylinder can be used in a pumped system. The matched solar cylinder will provide improved efficiency.

1.3 SYSTEMS AND APPLICATIONS

The low temperature systems available within New Zealand are generally small modular systems that can be combined in groups to make any size to meet specific heating requirements. The modules are generally small and easily moveable for installation on roofs without the necessity of heavy lifting equipment. Systems are available for new installation, or installation onto existing buildings, and with use of existing hot water cylinders.

For the solar thermal industry, technical barriers have been mostly resolved, at least for low temperature conversion. Systems have existed for some time now with sufficiently high efficiency at a cost likely to yield a very positive return over their lifetime. The systems will cost substantially less over the lifetime of the system than the cost of electricity needed to produce the same output.

1.4 TECHNICAL STATUS

Low temperature solar water heating is an internationally mature (commercial) technology.

Although the technologies used in the flat plate type solar collector systems are relatively old, incremental improvements have occurred over most of the last 10 years in two main directions. One has led to lower costs, the other to higher system performance. In the latter case, the two main limitations in the performance of the above systems are related to the optical properties of the absorbing surfaces used (selective and non-selective), and to the relatively sizeable heat loss by convection occurring in the collectors.

Recent advances in the performance of selective surfaces for solar energy conversion have led to new industrial production of high performance selective surfaces with high solar absorptance and very low thermal emittance. This enables these surfaces to reach temperatures of 300^oC and above. When these characteristics are combined with reduced convection losses, the performance of a solar collector follows a substantially improved efficiency curve.

These developments are opening up a new set of applications for solar thermal conversion operation at mid temperatures. These include commercial and industrial hot water supplies for food processing and the dairy industry, heat for sterilisation at around 85^oC, and applications in heating and cooling via high efficiency refrigeration cycles operating at 150^oC and above.

Application of this higher temperature technology is at the demonstration stage at several European projects. So far, no application of these systems is being undertaken in New Zealand even though some evacuated tubes of this type are available here. Other approaches have been examined.

All these high temperature plants outputs depend critically on the long-term availability of direct solar radiation. Thus, they are not likely to have a high output in New Zealand's relatively variable irradiance conditions. Consequently they are unlikely to be economically viable even when capital costs are reduced.

1.5 APPLICATION LIMITS AND SYNERGIES

Solar heating technologies are modular in nature and are therefore adaptable to a variety of applications that vary in size, output temperatures and other operating requirements.

There is a lack of adequate information to ensure public awareness of the technology and its advantages. This lack of awareness spreads through to all sectors of this industry.

Presently available flat plate systems (unglazed or glazed collectors) are mostly limited to operating temperatures below 60^{o}C in order to maintain a relatively high conversion efficiency. This makes them useful for solar swimming pool heating (~30^{o}C) and solar domestic hot water applications. These two areas have been the main applications in New Zealand.

A benefit of solar heating lies in it being a distributed energy supply system that is independent of the costs of a central energy supply network. The failure of one solar water heating system may be a problem to one user, but will not affect an entire city or the nation.

The solar thermal technologies that seem most appropriate for New Zealand's insolation values are low and mid temperature systems collecting global irradiance. While in relatively common use for domestic water heating, commercial or industrial scale collectors have so far not been widely adopted, despite recent advances and technical feasibility.

The pumped system can be connected to existing hot water storage cylinders and are therefore cost effective when retrofitting on to an existing house. Both pumped and thermosiphon systems are appropriate when a new house is being built or an existing hot water cylinder requires replacement or if additional hot water storage is required in which instance the system is installed as a preheater.

From an economic standpoint, retrofits to existing homes for thermosiphon systems do not benefit from savings in the construction costs that new installations would occasion. At an average cost of around $4000 to $5000 for a full installation in a residential home, these systems would be most economic when replacement of existing hot water cylinder is required. On the other hand thermosiphon systems have the advantage that they can be expressly independent of electricity, although usually they still have an electric or gas secondary heating element to provide backup heating of the hot water, or a solid fuel stove (wetback) may also be fitted.

Pumped systems are very versatile as the hot water storage cylinder can be located anywhere in or outside a building.

Solar technologies are easily integrated into new or existing buildings, they can be unobtrusive, can enhance the aesthetics and architectural appeal of buildings, and are often considered a positive asset due to their green image.

Installation of solar heating currently is not perceived by house buyers to add value to the price of a house. It is not sufficiently valued at national and regional levels or in regulations and standards, hence has little or no marketable value at present.

The technology has a large potential for cost reduction in the near future due to technological advances and increased production based on substantial market expansion. Market expansion will also result in improved results from marketing. Currently market initiatives are focussed on creating a market. With an expanded market solar system suppliers would be undertaking promotion within a market. It has been assessed that with a larger market costs could easily drop around 20% within ten years.

1.6 CRITICAL FACTORS

The main immediate markets for solar water heating in New Zealand are the residential and commercial building industries.

The main cost barrier to the dissemination of solar technologies is ostensibly their initial capital cost to the users.

The building industry's traditional conservatism towards solar systems (and that of associated trades and professions, i.e. builders, carpenters, plumbers, architects), their lack of awareness, understanding, and experience of solar water heating constitute a major barrier to adoption of the technology.

As distinct from other renewable technologies solar heating requires the end user to make the capital investment. Capital cost can therefore be a barrier to uptake.

For commercial and industrial use, the availability of the resource through location and specific heating requirements will affect the financial suitability of solar water heating.

General uptake will be assisted by a newly introduced method of building energy rating. This will enable purchasers to assess the benefits of the energy options fitted to a building in the same way that a purchaser would take rates (for instance) into account.

1.7 Environmental Issues

In use, solar technologies do not contribute to any known form of pollution (air, land, water) or greenhouse gas emission.

Solar energy is distributed right across the country, requiring neither transportation nor any special infrastructure for its use. It can be collected at its location of use.

Solar water heating can reduce the market demand for electricity and as a result marginal thermal electricity generation.

2. New Zealand Resource Information

2.1 Information Sources

The information on the solar hot water system availability and possible uptake is taken from the recent EECA publication "Solar Energy Use and Potential in New Zealand".

Cost information has been sourced from members of the Solar Industries Association and trends assessed from various Australian published information.

2.2 The Location of Resources

Solar energy is available throughout New Zealand, but as well as the obvious regional, diurnal, and seasonal variations the actual amount available varies due to specific local factors, e.g. topography, nearby natural and manmade objects, i.e. buildings, trees, hills, etc., and orientation of site.

The sunniest regions are near Blenheim, the Nelson-Motueka area, and Whakatane where the average duration of bright sunshine exceeds 2,350 hours per year. A large portion of the country has at least 2,000 hours, and even Westland with its high rainfall has 1,800 hours. Southland and coastal Otago, where sunshine drops sharply to about 1,700 hours per year, lie on the northern fringe of a broad zone of increasing cloudiness. Unlike many of the countries leading the development of solar energy technologies (notably in Europe), New Zealand has a high proportion of sunshine during the winter months. There is a marked winter increase in cloudiness in the North Island but not in the South Island except in Southland.

2.3 THE QUANTITY OF THE RESOURCE

The values of daily energy are similar for all sites in Kaitaia, Paraparaumu and Invercargill. The maximum values are about 30MJ/m^2 per day in January decreasing to a maximum value in winter of about 8-12MJ/m^2 per day for all sites. Invercargill, the lowest valued New Zealand site shows lower daily values (of about 15% through the year) indicative of its southernmost position.

All other sites are only slightly lower than Australian sites. Sites in New Zealand such as Nelson, Blenheim, Gisborne, and Hawkes Bay are expected to have comparable or higher values than Melbourne.

Table S1: Typical values of total yearly global energy per sq.m. for several sites in New Zealand. Two units have been used. (1 kWh= 3.5 MJ).

	MJ/m^2/yr	kWh/m^2/yr
Kaitaia	5,288	1,469
Paraparaumu	5,035	1,403
Gisborne	5,386	1,497
Christchurch	4,989	1,361
Invercargill	4,652	1,292

Most solar collection systems are tilted towards the equator, enabling them to collect substantially more than the horizontal values above. For example, in Wellington a flat plate facing northward and titled at around 35^{o}C from the horizontal, would increase its yearly solar energy collection by about 15% or to over 1,650 kWh/m^2 per year.

2.4 VARIABILITY OF SUPPLY

In general, solar technologies provide energy only for use on site. This is largely due to the high energy losses, and the high costs, of transporting low grade heat more than short distances.

As solar energy is not available 24 hours a day, in order to support continuous processes (e.g. food processing or living) it is necessary to store it, minimise the loss of the collected energy and provide where necessary some form of alternative energy source as a back up.

An average house rooftop of 150m^2 intercepts $2.2x10^5$ kWh per year of solar energy, more than 20 to 30 times the house's total requirements. The total household rooftop area in New Zealand is exposed to primary solar energy that is equivalent to about twice the total national energy consumed. However, the resource is relatively low in intensity and intermittent in availability.

It is unlikely, except for some commercial and industrial applications, that the land areas required to collect solar energy would be beyond that already covered by the building within which the energy was required.

2.5 CURRENT SITUATION AND POTENTIAL CONTRIBUTION

Solar hot water technologies currently have net conversion efficiencies of sunlight to hot water of an average 35 - 45% of all the radiation falling on the panel areas, and contribute more than 40 GWh (0.1% of New Zealand electricity consumption) electricity equivalent per year. They are cost effective in a number of applications at 7-10 c/kWh.

It is estimated that the present yearly sales of solar thermal systems includes 4,000m^2 to 4,500m^2 of collector area for swimming pool heating and ~1200 units (equivalent to ~4,000m^2 to 5,000m^2) for residential solar hot water. Given an average energy production of 2,500 kWh per year from each hot water system, this yields a yearly increase in energy produced from solar thermal (pool and residential) in 1999 of ~11,500 MWh.

A first optimistic scenario, would expect an increase in the market of 10 to 15 times. This is equivalent to 10 to 15,000 new solar equipped houses or 25% of new hot water cylinders installed per year. This might be brought about by simple measures such as a closer synergy between the solar industry and the building industry, and a substantial marketing and awareness programme.

A maximum scenario might be occasioned by mandatory energy efficiency requirements on all hot water systems. This would see a rate of solar uptake matching the rate of new installations, i.e. ~60,000 per year. The equivalent electricity savings from this would amount to over 150 GWh per year (60,000 x 2,500 kWh/yr) from new systems. This would take the total installed capacity to 315 GWh per year by 2012, and with an additional 150 GWh each year, an estimated maximum 665 GWh per year by 2025.

Experience shows maximum uptake is more likely to be around half of the new housing stock. Annual new house permits are at about 21,000 per year. This assessment of 10,000 systems per year over the next few years is also supported by the Solar Industries Association who assess that a market size of 10,000 new systems per year is most likely provided that an extensive promotion campaign is undertaken to get solar systems included as an integral component of new house design.

By the year 2012 solar hot water could contribute between 215 and 315 GWh per year. By 2025 their wider adoption would replace upwards of 15% of domestic hot water requirements (up to 600 GWh per year) and a proportion of commercial and industrial heat requirements.

This could replace fossil thermal electricity generation and create direct employment for over 400 people. It would mitigate in the order of 270,000 tCO_2 annually from alternative thermal generation.

3. ENERGY SUPPLY COSTS

3.1 CAPITAL AND OPERATING COSTS

There are nine manufacturers or importer/suppliers of solar systems within New Zealand.

There is a mixture of thermosiphon and pumped systems. Some suppliers of pumped systems also offer special solar system hot water storage cylinders.

The cost data is difficult to put on a comparable basis as some systems include the storage tank, while others may make use of existing installed hot water cylinders. There are no reliable statistics on the number of the various systems installed.

Nonetheless installed prices range from $3,000 to $5,000 for 2-4 square metres of collector. This study is concerned to identify the likely minimum entry cost situation on an average basis for an installed system with frost protection. In this context a price range of $3,000 to $3,500 appears realistic after deducting the cost of the conventional hot water cylinder that would otherwise be required. For this study a minimum entry investment assuming use of existing hot water cylinders, or allowing for the cost of the cylinder, has been used as it would be included in a house anyway.

Although the marginal cost of incorporating a solar water heater in a new domestic building is low the same may not be the case for retro-fitting a system to an existing building. Thus, we would expect the biggest market for domestic solar water heaters is likely to be in new buildings. For this study it is assumed that the majority of systems will be installed in new buildings.

No allowance has been made for the more expensive systems or for installation of high efficiency and larger hot water cylinders that could be chosen for installation.

Thermosiphon systems may also be more expensive but provide additional benefits to specific applications for the additional price.

For solar hot water the present lifecycle cost of producing a kWh equivalent can be estimated from the equipment and maintenance costs ($3,000-$3,500), the lifetime of the equipment (20 years), and the total number of electricity equivalent units produced during that lifetime (20 yr x 2,500 kWh/yr).

The cost of energy produced has been calculated at a range of discount rates as required by the project brief.

Table S2: Average cost of energy for a minimum investment system.

Average cost over 20 years	
0% Discount Rate	7 cents/kWh
5% Discount rate	10 cents/kWh
10% Discount Rate	14 cents/kWh

This calculation does not include for any of the benefits of solar water systems as these are not relevant to calculating the cost of energy production. Such benefits would be included in a cost / benefit calculation showing the financial benefit to home owners of investing in a solar system.

Homeowners are likely to have a discount rate of 0% or 5% as their target value of money. The value of 7-10 c/kWh obtained indicates that solar domestic hot water is cost competitive with retail electricity tariffs throughout New Zealand and the maximum yearly output from this source is only limited by the number of systems that can be installed.

The difference in cost between retro-fitting and installation in a new-building need not be true for commercial and industrial uses, where the scale of application may make the connection cost a small component of the total installed cost.

3.2 COST ESTIMATES IN THE FUTURE (2012, 2025)

Capital Cost

The capital cost referred to in this review is the marginal capital cost. It is assumed that the dwelling will already have an electric hot water cylinder or would purchase and install one independent of the decision to install a solar system. With the thermosiphon systems the cylinder in the system replaces the need to buy a conventional hot water cylinder.

Basic systems have been assumed. It is assumed that the pumped system uses conventional hot water cylinders. More efficient storage cylinders designed for a solar system are not included.

The costs are based on a minimum entry of investment in a solar system and do not include larger systems that are fully independent of the mains electricity supply.

Although the technology is mature, a major increase in production and installation could see some cost savings over present. A report prepared for the Australian industry suggests a 2%/year price reduction over the next 10 years. It is assumed that this will take into account exchange rate changes. In New Zealand there are likely to be economy of scale benefits as the industry expands. These will then level off as the technology is relatively mature.

Cost assumptions include frost protection.

Table S3: Solar Capital Cost Trends

Year	New House
2001	$3,000
2012	$2,500
2025	$2,500

Repairs and maintenance

A solar water heating system can be expected to have an operating life of at least 20 years.

Data on maintenance costs of solar water heating systems in New Zealand is very limited. The maintenance cost is assumed to be of the order of $100 every five years for a domestic installation. This would include cleaning the glazing and replacement of deteriorated pipe insulation, etc.

The economics of mass production are likely to ensure that spare parts are readily and cheaply available.

Operating costs

A thermosiphon solar water heating system requires no additional purchased energy to provide its contribution of energy.

However, a pumped system would require purchased electricity for the pumps. There is no monitored information available on the amount of electricity required under New Zealand conditions but this is assessed to be around $12/yr.

Salvage / residual value

Depending on the material used in the construction of the collector panels, the scrap value at the end of an assumed 20 year life may range from almost nothing (pressed steel panel) to less than $100 (copper panel). The trend is towards non-copper panels, and non-copper storage cylinders, so the expected salvage cost is likely to be low.

However in order to calculate the residual value the cost of installation is not insignificant, and in cases where a "worn-out" collector and hot water cylinder are replaced at the end of a 20 year life, the benefits of the existing installation would be of the order of $500 (based on possible installation costs in a new building).

3.3 NATIONAL SUPPLY CURVE DATA

The results of the scenario modelling are included in Table S4

Table S4: Assessment of Possible Future Energy Production

Possible Energy Production / Cost Data							
	c/kWh	By Year 2012			By Year 2025		
		GWh/y			GWh/y		
		WACC =0%	WACC =5%	WACC =10%	WACC =0%	WACC =5%	WACC =10%
High Confidence	4-6	-	-	-	-	-	-
	6-8	100	-	-	200	-	-
	8-10	110	100	-	330	200	-
	10-12	5	110	-	10	330	-
	12-14	-	5	100	-	10	200
	14-15	-	-	110	-	-	330
Medium Confidence	4-6	-	-	-	-	-	-
	6-8	100	-	-	250	-	-
	8-10	160	100	-	290	250	-
	10-12	5	160	-	5	290	-
	12-14	-	5	100	-	5	250
	14-15	-	-	160	-	-	290
Low Confidence	4-6	-	-	-	-	-	-
	6-8	150	-	-	300	-	-
	8-10	150	150	-	360	300	-
	10-12	5	150	-	5	360	-
	12-14	-	5	150	-	5	300
	14-15	-	-	150	-	-	360

4. FURTHER RESEARCH AND OTHER ISSUES

Information on the economics and lifetime performance of solar systems is required.

A wider awareness of solar systems is necessary amongst builders, plumbers, and architects.

Potential owners of solar systems need to be able to see more systems installed and working satisfactorily.

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CHAPTER 8 – SOLAR (PHOTOVOLTAICS)

1. TECHNOLOGICAL INFORMATION

1.2 ENERGY RESOURCES

Solar resources were covered in the previous chapter. It is the most abundant primary energy supply in New Zealand. Solar energy has been converted into electricity at a cost suitable for small niche markets. Photovoltaic (PV) electricity is well established in stand alone applications in remote areas. However the technology is rapidly advancing, and an increasing proportion will be taken up for grid-connected applications (EPRI 1997).

Currently, PV electricity is beyond the 15c/kWh cutoff limit of this report (EECA 2001). However, the unit cost is dropping rapidly such that over the period to 2025, PV is likely to mature and enter the wider domestic-level grid-connected market. As such, PV will be competing against the retail cost of electricity rather than wholesale alternatives.

The energy from the sun is traditionally measured according to three parameters:

- Global irradiance – the power per unit area on a horizontal surface from the whole sky.
- Direct irradiance – the power per unit area on a surface always facing the sun direction.
- Diffuse irradiance – the power from the whole sky excluding the direct irradiance

An average house rooftop of 150m^2 collects 220MWh per year, more than 20-30 times the house's total requirements.

However the solar resource is relatively low in intensity and intermittent in availability. Peak energy availability is during the middle of the day, whereas peak energy demand at the household level is morning and evening.

1.2 SYSTEM ELEMENTS

Direct solar to electricity conversion can be carried out with Photovoltaic cells. These are usually solid-state semiconductors that generate an electrical potential when exposed to light. These cells are made from a variety of semiconducting materials either in single crystal form (silicon, gallium arsenide (GaAs), indium phosphide), in multicrystalline and polycrystalline form (silicon, cadmium telluride (CdTe), copper indium gallium diselenide (CIGS)) or in amorphous form (silicon, silicon-germanium alloys). In each the laboratory and commercial production techniques differ, with differing performance resulting. Only a small number of cell designs have reached industrial production.

Most industrially produced cells are silicon with efficiencies of around 15% (versus lab efficiencies of up to 24.5%).

About 60% of current production is based on single crystal flat plate technology, 25% on polycrystalline silicon technology, and 11% on amorphous silicon technology (Redding 1999).

For complete functionality, PV modules require various components such as the structural supports, charge controllers, inverters, batteries and safety disconnects. There may be special metering requirements where export may occur.

1.3 SYSTEMS AND APPLICATIONS

The main applications can be divided into four broad sectors (including two distinct types of grid-connected systems) (EECA 2001):

- Consumer products – These (after space applications) were the first commercial applications of PV e.g. calculators, watches, toys. They also included individual power supplies (caravans, mobile homes, boats) and individual supplies for novelty products (home security, garden lighting, car sunroofs, fans and battery chargers).
- Industry applications – PV systems can be sold to a service industry, especially “professional systems” provided by companies active in the communication industry and the cathodic protection industry. New Zealand’s electric fence industry is a substantial and good example.
- Standalone Power System (RAPS) applications – These are applications in the watts to kilowatt size range located at sites remote from the main distribution grid. This will be a pivotal growth area in a number of countries for applications like water pumping, water treatment, electric supply to small industry, domestic/medical/institutional uses and communications links.
- Grid connected distributed supply system applications – These are a newer but vigorously growing example of PV use in the urban environment. These systems are simpler than RAPS as they require only PV panels and inverter to provide AC voltage and connect to the local distribution grid. The main electricity supply acts as a storage facility, receiving electricity at times of PV surplus and supplying it at times of PV deficiency, hence there is no need for a battery system. Agreements and standards for electricity transfer in both directions on and off the site are usually required. These systems provide electricity at the consumer end of the distribution chain and compete with the retail price of electricity. (A variation on this has been investigated in the US where utilities will install systems in neighbourhoods, relieving local distribution networks but largely competing at the wholesale end of the market).
- Grid connected power plant applications – These have been trialled overseas to a size of >1MW. These include both full scale central PV stations feeding power to the distribution grid, and embedded generation PV systems used to correct either overloads or degraded power quality at critical points, (thus deferring substantial capital and maintenance expenditures on transformers, lines etc). A very successful illustration of this embedded application is found in the Kalbarri 20kW PV system in Western Australia. (These applications include both utility-scale, flat-plate thin film PV and concentrating PV).

The focus of this report will be on domestic/commercial-scale applications.

1.4 TECHNICAL STATUS

PV has been commercialised in specialist small-scale applications since the 1970’s. First trials of MW-sized utility systems were installed in the 1980’s. Several countries have large-scale demonstration plants, but growth and the bulk of capacity are at the domestic and commercial level with an increasing proportion being grid-connected.

Systems are reliable such that PV modules carry a manufacturers guarantee of 20 years.

The PV industry appears to have reached a critical level such that sales are increasing rapidly allowing large-scale manufacture with associated price reduction. This in turn is boosting demand.

A trend in the PV industry worldwide has been the involvement of all major petroleum companies in the ownership, direct production and promotion of solar energy, especially PV electricity production. This has seen recent company amalgamations, and the establishment of larger scale PV production plants (10 to 100MW/year) in Australia, Europe and USA which may realise substantial economies of scale. These large plants have been developed on the assumption of an explosion in demand in the near-term estimated in the range 30 to 45% per year for an indefinite period (EECA 2001). A more conservative industry view would place long term growth at 25% per year (Redding 1999).

Several laboratory technologies are being transferred to industry (e.g. laser grooved buried contact patterning, single crystal silicon, production of large thin films) with consequent efficiency gains or reduced cost due to less material and lower production costs.

It is likely that PV technology will continue to enjoy spin off benefits from developments in the microelectronic industries generally. The current worldwide investment in new materials and devices by these industries is very large and technological breakthroughs applicable to PV systems are likely.

1.5 APPLICATION LIMITS AND SYNERGIES

PV power systems are versatile as to their size and power output, from microwatts for calculators to megawatts and larger for central grid connected power stations. System availability should be quite high (85-95%) and maintenance needs will be modest.

Out of Australia, there are packaged PV and PV/diesel hybrid systems in the kW load range from a number of suppliers.

The possible markets for these systems are also diverse, often with quite different and opposing requirements. Refer to section 1.3 for a description of the applications.

PV is the energy source of choice for navigation lights, telecom sites and isolated or remote areas (including Antarctica) where reliability and low maintenance are of the utmost importance.

The PV industry in New Zealand comprises mainly distributors of imported modules and a network of equipment installers. Some ancillary equipment is made locally. There is no PV manufacturing capability in New Zealand.

The New Zealand oil companies Shell and BP, as well as Canon, have published their intention to import and supply PV modules and systems in New Zealand.

Some technical developments in building electrical systems may be beneficial to PV power installations. For example, low voltage, direct current lighting systems could form ideal loads for PV systems and remove the need for inverters thus improving the overall economics (Redding 1999).

One niche market for PV in New Zealand has been for electric fence applications. Rural uptake could extend further after 2013 when electricity distribution companies are no longer obliged to maintain rural supplies.

1.6 CRITICAL FACTORS

PV cost is still high but should drop rapidly.

1.7 ENVIRONMENTAL ISSUES

PV has low environmental impact so is very attractive. Full lifecycle analysis does indicate surprisingly high carbon emissions mainly associated with the processing of the raw materials. This activity would be focussed offshore.

This technology is regarded as one of the most attractive green technologies.

Solar technologies are easily integrated into new or existing buildings, they are unobtrusive, can enhance the aesthetics and architectural appeal of buildings and are often considered a positive asset due to their green image.

2. NEW ZEALAND RESOURCE INFORMATION

2.1 INFORMATION SOURCES

Information on the technology is rapidly being updated. A good status summary was published by EPRI in 1997. The Australian Greenhouse Office has released a report (Redding 1999) on a range of technologies including PV. EECA have released an assessment of Solar Energy options for New Zealand applications in May 2001.

2.2 THE LOCATION OF RESOURCES

Solar energy is accessible anywhere.

2.3 THE QUANTITY OF THE RESOURCE

An average house rooftop of 150m^2 collects 220MWh per year, more than 20-30 times the house's total requirements.

Table PV1: Typical Yearly Global Energy at Various Locations (EECA 2001)

Location	MJ/m^2/year	kWh/m^2/year
Sydney	6,150	1,708
Melbourne	5,302	1,473
Kaitaia	5,288	1,469
Paraparaumu	5,035	1,403
Gisborne	5,386	1,497
Christchurch	4,898	1,361
Invercargill	4,652	1,292
Germany	3,609	1,003
US	6,480-8,280	1,800-2,300

Note that appropriate panel orientation can increase panel output by 15%.

2.4 VARIABILITY OF SUPPLY

The solar resource is relatively low in intensity and intermittent in availability. Peak energy availability is during the middle of the day, whereas peak energy demand in New Zealand at the household level is morning and evening. This is in contrast with parts of Australia or California where peak demand is driven by air-conditioning requirements.

The following graphs show variability on a daily basis for sites in Australia (as examples of daily average variability) and on a monthly basis for sites in New Zealand.

Figure PV1: Total Daily Global Irradiance as a Function of Day of Year for Two Typical Sites in Australia (EECA 2001)

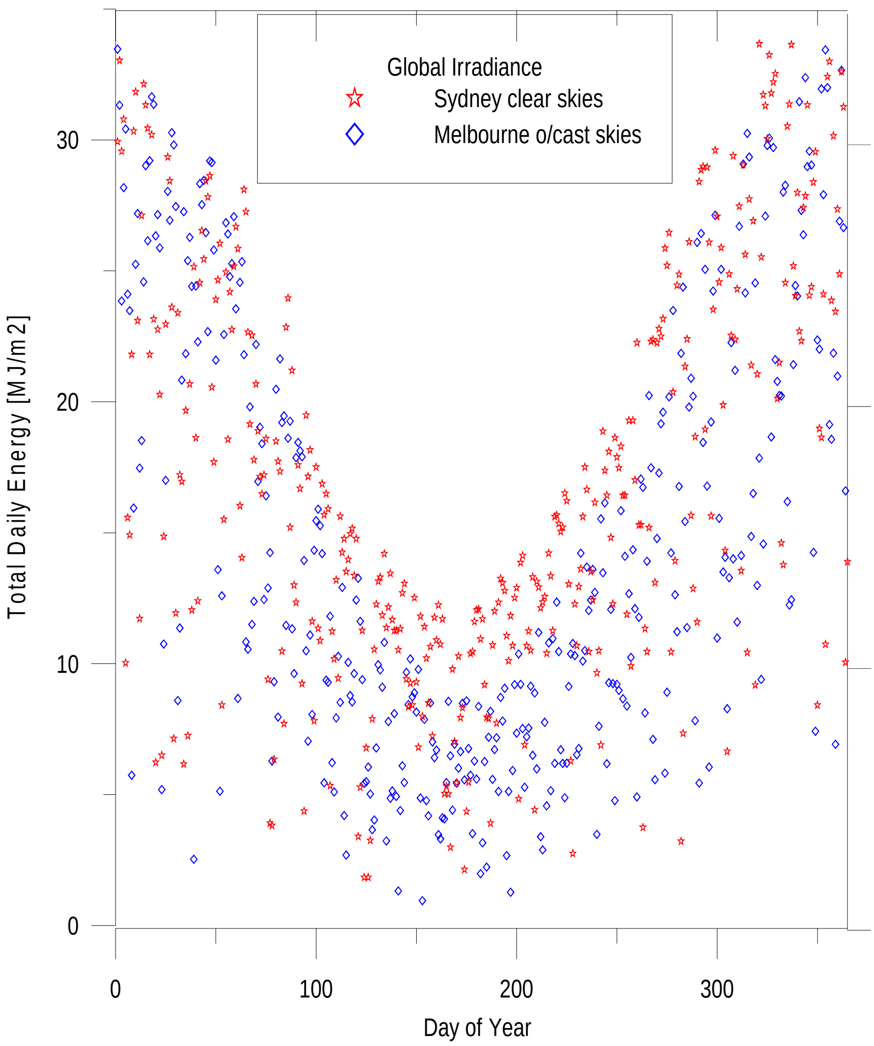
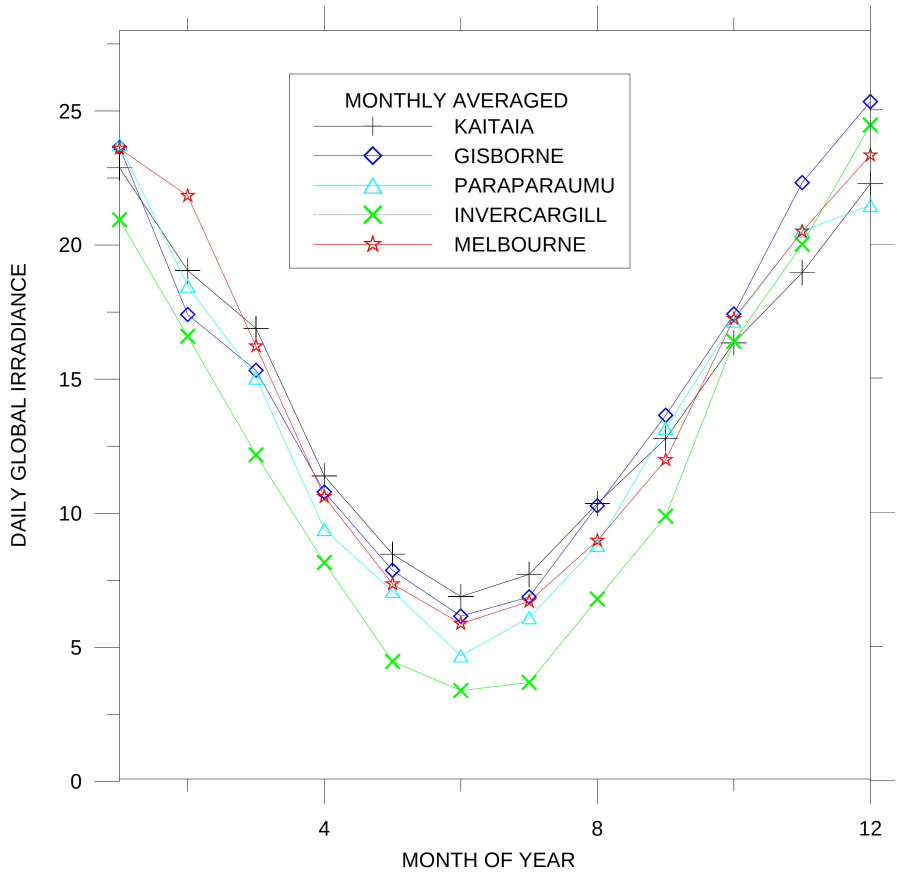


Figure PV2: Monthly Averaged Daily Global Irradiance at Several Sites in New Zealand (Including Calculated Melbourne Values from Above) (EECA 2001)



2.5 CURRENT UTILISATION OF RESOURCES

PV applications have increased steadily in New Zealand over the last 4 years, due mainly to remote area installations for telecommunications, site monitoring and government activities in parks and reserves. It is estimated that in 1997, 1998 and 1999 volume of sales has increased from 91kW and 101kW to 146kW per year.

This level of sales is expected to have resulted in a total installed capacity in New Zealand of between 800kW and 1MW and a yearly electricity generation of ~1,280 MWh (EECA 2001).

2.6 INFRASTRUCTURE OBSTACLES

The main impediment to further uptake of PV technology has been its cost compared to grid electricity prices.

2.7 VIEW ON UPTAKE

Uptake of PV on the international scene has been on an exponential basis, with similar trends evident in New Zealand. New Zealand's uptake will be assisted by the expanding international sales forcing down prices generally. However our uptake path may be somewhat different to other countries. Points of difference include:

- *Daily load curves*. New Zealand's electricity peaks are early morning and evening when solar contribution is minimal, while places such as Australia and California have strong air-conditioning loads timed during the day when solar can relieve the peaks. Because PV will not relieve peaks, but will reduce local demand, installation will decrease the capacity factors of local distribution companies. They will not want to send price signals to encourage this.

- *Current low price of retail electricity*. This sets the target for PV lower than other countries.
- *Solar Global Energy levels*. New Zealand receives 1,300-1,500 kWh/m^2/year of solar global energy, while the US works on 1,800-2,300 kWh/m^2/year. The low insolation values reduces the system capacity factor reducing the number of kWh over which the capital investment can be spread.
- *Absence of a PV manufacturing base*. New Zealand does not have a PV manufacturing base, so has no need to provide a nurturing ground for its development over and above other renewables. The US, to encourage its industry has a Million Solar Roof Initiative which aims for one million roofs with solar panels by 2010. Other manufacturing countries have government-based incentive packages.

Costs will be outlined in section 3.1 and 3.2. Costs are still far from competitive (except in niche areas). This must be qualified by the recognition that these costs should be compared with the retail price rather than the wholesale price, as such systems represent the deepest level of embedded generation. Further, people investing at this level will be using different investment criteria to large utilities.

By 2012, the unit cost is expected to be in the 27-48c/kWh range. While this would appear to be excessive, a large number of farmers will be favourably comparing this price with that of diesel generation, the alternative for farming communities with networks seen as too expensive to maintain.

By 2025, the unit cost will be in the 12-21c/kWh range. The bottom end of this range is comparable with current retail prices. Any upward movement in wholesale price will lift the retail price further into this range, and may see the start of a mass uptake at the retail end of the market.

Three uptake scenarios are shown in Table PV2, each based on exponential growth, essentially on a “business as usual” basis, from high to low confidence. These cover the range of growth rates reported in technical assessments.

Table PV2: PV Uptake Scenarios

Year	2012			2025		
Capacity	MW	GWh/y	Market Share (%)	MW	GWh/y	Market Share (%)
High Confidence (25%/a growth)	13	19	0.04	230	340	0.6
Medium Confidence (37.5%/a growth)	40	58	0.13	2,500	3,700	6.4
Low Confidence (45%/a growth)	77	110	0.24	9,600	14,000	24.0

The table shows low level penetration by 2012, but significant levels by 2025. The low confidence values could only be achieved if international uptake was also high, in which case even lower prices than anticipated in section 3 may be reached. The levels could only be achieved with units on virtually every home and office. The low confidence case stretches credibility, and it could be argued that exponential growth will drop off as the market moves through different phases. However, it does reflect the almost infinite power source available through solar energy.

As a crosscheck on the reasonableness of the scenarios, a fourth scenario was also considered, prorating the US Million Roof Initiative by New Zealand's population and remaining time. This would effectively lead to a 10,000 roof target for New Zealand by 2010 (about 6% of new housing stock over the next 8 years). This equates to a target of 40GWh/y, a figure easily achieved by the medium confidence level scenario. An implication is that the US Million Roof target is little more than a co-ordinated business-as-usual case.

3. ENERGY SUPPLY COSTS

3.1 CAPITAL AND OPERATING COSTS

Long-range prices have been provided by EPRI for the US (EPRI 1997). Shorter-range projections of costs have been provided for Australia (Redding 1999). These have been converted to New Zealand dollars, fitted by an exponential function and averaged. The exponential functions show good agreement for later dates, though the large changes predicted must call any projection into doubt. The resulting curve fits current capital costs at around NZ$10/Wp.

For a typical 20 m^2 roof-top grid-connected PV system:

Capital Cost, $C = NZ\$2.98 \times 10^{57} \times e^{-0.065 \times Year}$ /Wp

O&M (fixed) = $46/year

Table PV3 shows these costs and expected performance for New Zealand conditions. The highly modular nature implies little or no economies of scale.

Table PV3: Expected Costs and Performance of Grid-Connected PV at a Domestic Level [1]

Year	2000	2012	2025
Unit Size (m^2)	20	20	20
Unit Size (kWp dc)	3.2	3.64	3.9
Unit Size (kWac)	2.6	3.04	3.3
AC System Efficiency (%)	13.1	15.3	16.6
Annual System Performance (1300 kWh/m^2/year)[2]			
AC Capacity Factor (%)	17.2	17.2	17.2
Energy Produced (kWh/year)	3,917	4,575	4,963
Annual System Performance (1500 kWh/m^2/year)[2]			
AC Capacity Factor (%)	19.8	19.8	19.8
Energy Produced (kWh/year)	4,520	5,279	5,727
Capital Costs			
PV Module Cost ($/Wp)	6.64	3.10	1.35
Total BOS ($/Wp)	4.55	2.03	0.85
Total System ($/Wp)	11.19	5.13	2.20
Total System ($)	35,800	14,400	8,600
System Operations and Maintenance Cost			
Maintenance (annual) ($/$m^2$/year)	2.3	2.3	2.3
Total Annual Costs ($)	46	46	46

1. Table is based on Table from EPRI 1997, but modified for New Zealand conditions and prices.
2. Effective insolation values have been increased by 15% in calculations to account for favourable orientation of panels.

3.2 SENSITIVITY

The costs given above are based on long-range projections of cost and performance. Large changes are forecast for which there must be great uncertainty. Accuracy will be less than ± 30%. However, at that level, there is a clear possibility of competitive rooftop generation by 2025.

3.3 COST ESTIMATES IN THE FUTURE (2012, 2025)

Future costs have been discussed in section 3.1.

3.4 ESTIMATED OVERALL COSTS

Costs and performance from table PV3 have been input into the financial model with the following results. Note that analysis has been undertaken at standard WACC values of 5% and 10% with a life of 25 years. However, domestic consumers will be using different investment criteria to utility investors.

Table PV4: Results of Financial Modelling (Unit Costs c/kWh)

	Year 2012 c/kWh		Year 2025 c/kWh	
	WACC=5%	WACC=10%	WACC=5%	WACC=10%
Insolation Value =1300kWh/m^2/y	31	48	14	21
Insolation Value =1500kWh/m^2/y	27	42	12	19

As discussed in section 2.7, costs remain high. At 5% WACC they are competitive with diesel generation by 2012, and likely to be competitive with the retail price of electricity by 2025.

3.5 NATIONAL SUPPLY CURVE DATA

While scenarios for uptake have been given in section 2.7, with in excess of 6% of the electricity market share being taken up by PV by 2025 under two scenarios, unit costs are in excess of 15c/kWh. For consistent treatment between all technologies, the national supply curve will show no contribution from PV.

In practice, the focus of MED interest is on 2012, and the contribution from PV to the electricity industry by that date will be small.

4. FURTHER RESEARCH AND OTHER ISSUES

New Zealand will not take a lead in this technology, but Australia will remain very active in photovoltaic research and development. Focus in New Zealand should be on following these technologies. Special consideration could be given to potential uptake for rural communities which will be impacted by uncertainty of electricity supply beyond 2013, for which the alternative may be diesel electricity at over 40c/kWh.

The PV industry is experiencing rapid development. PV will continue to increase its penetration of the New Zealand electricity market. Eventually PV should compete at the retail end of the market for grid-connected applications.

References

Electric Power Research Institute (1997). *Renewable Energy Characterizations.* A Joint Project of Electric Power Research Institute and Office of Utility Technologies Energy Efficiency and Renewable Energy U.S. Department of Energy, EPRI TR-109496, December 1997.

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APPENDIX C: GRID-CONNECTED, EMBEDDED AND ISLANDED GENERATION

Paradigm Shifts

A decade or so ago, government energy planning was largely based around electricity with generation at large centralised power stations feeding directly into the national grid. A number of paradigm shifts have occurred in the intervening years:

- There is wider recognition of the value and importance of both heat and electricity.

- An open market for sale and purchase of electricity has been established, with associated market-based regulations governing market operation.

- There has been clear separation between generation, transmission and distribution, with reasonably transparent pricing regimes allowing isolation of costs. Regulations, where they exist, aim to ensure fair returns and pass through of costs for the natural monopolies. This helps investors realise benefits of generation feeding loads at different levels.

- Investment in generation can now be (and is frequently) by private power interests, or by state owned electricity companies. For some years now there has been no centralised state utility with overall responsibility for electricity generation.

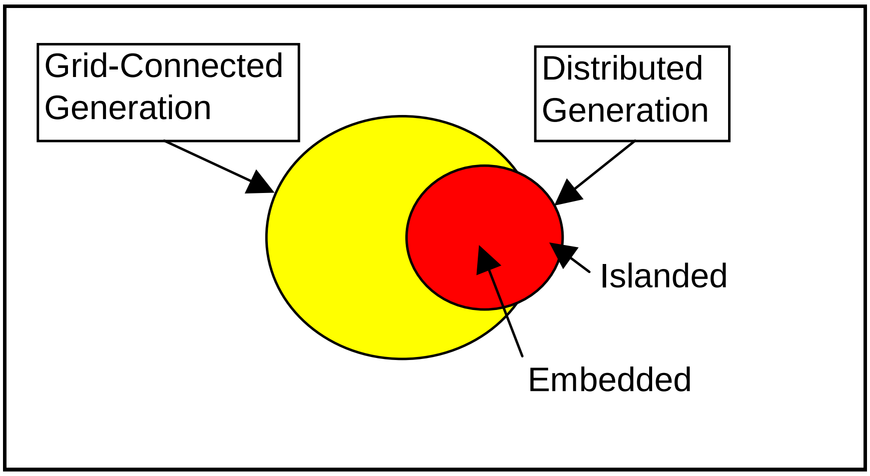
- Some industrial concerns have recognised the benefits of cogeneration/combined heat and power and have invested in prime opportunities, especially those possible through an abundant natural gas supply. Marketing by gas companies has seen cogeneration implementation down to small hospital/commercial level.

- World research and development is now focussing on distributed generation as a means to ensure quality of supply, relieve transmission constraints or reduce transmission related costs, and secure a better electricity price. Technologies are being developed or adapted to focus on this mini- and micro-generation.

- Principal regulation of projects is environmental through the Resource Management Act. This necessitates in practice benefits of energy projects being perceived to outweigh environmental losses.

A consequence of these paradigm shifts is that generation is now being installed at a deeper level within the electricity network. The following paragraphs outline the characteristics of these differing levels of generation. Figure C1 indicates the relationship between the grid-connected and distributed generation options.

Figure C1: Relationship Between Generation Options



Grid-connected Generation

Any generation that is synchronised to the grid can be said to be "grid-connected". Thus a small photovoltaic cell on a home may be grid-connected. There is a cost associated with synchronisation equipment. But at the mini- and micro-generation scale, the overall costs of enabling synchronisation tend to be independent of size, as equipment costs can be overwhelmed by the relatively fixed costs of planning and testing.

Islanded Generation

Islanded generation refers to generation that feeds a load that is either not connected to, or which has been disconnected from (or is remote from) the local electricity grid. These systems can function well, as long as the equipment supplied by the generator has been appropriately designed for the delivered voltage and frequency (even a direct current supply is possible). Examples could include a remote farm, or a company that has made a strategic decision to operate on its own supply and operates disconnected from the grid. In these applications there is no interaction between generation, load and the national grid. There are no costs associated with synchronisation, but a risk is introduced in that generator outage (if not supported with backup generators) will result in failure of electricity supply with resulting effects on factory/business operations.

A grey area exists, where the load can be either grid-connected or islanded. The generator will operate on the islanded side so does not have to be synchronised. However, every kWh supplied by the generator of the isolated system is a kWh saved from the grid. Examples of this include use of backup generators in hospitals, prisons, factories, hotels or pumping stations.

In the short to medium term, islanded generation is expected to be only a small contributor to the national electricity supply. Where it can be used to progressively isolate a site from the grid, it can have an impact on peak load management and can affect peak price on the spot market if on sufficient scale.

Embedded Generation

Generation can be connected to the grid at a range of levels, each with their own costs and benefits.

Traditionally, large power stations have directly fed into the national grid through a dedicated substation (Grid Supply Point) at transmission voltages. Generation would generally be too great to be absorbed by the local network company so would be bid into the New Zealand Electricity Market to receive the pool price. This would not normally be considered embedded generation.

Many of the renewable energy opportunities are in the 5 to 100MW class. Depending on location, there may be opportunity to feed this directly to the network company. The network companies draw their electricity through a number of Transpower substations (Grid Exit Points). Voltages are dropped at these Grid Exit Points (GXPs) from the National Grid supply voltage (110kV or 220kV) to a local operating voltage typically 11kV or 33kV. Generation could conceivably be fed into the downstream side of these substations, or further down the line at network company sub-transmission stations, at lower voltage. Lower voltage implies reduced station transformer costs, but also means input into lower capacity parts of the system.

There are losses associated with transmission and distribution of electricity. Losses in the transmission system lead to nodal pricing which can allow some generation at the end of long transmission legs to secure premiums of up to 1c/kWh (as in Northland) compared with generation from South Island hydro stations. Station generation, even if fed into a subtransmission station, is generally recognised at the nearest GXP, and local network losses (typically in the 3% to 11% range) are subtracted off the net generation from the station in determining its revenue.

The network company may consider passing on a portion of the discount they receive from Transpower for reliable system relief. The network may also pass on some benefits if they are able to avoid local system strengthening due to the presence of the generation.

In some cases, generation may be installed in a factory, office or home. Voltage will be chosen to match the local site distribution. In some cases this electricity generation would be simply netted off the load. In other cases it may be sold back to a retailer through the network company. Benefit would be site-specific and a strong function of the local tariff structure offered by the site electricity retailer (including any pass through or other basis for pricing lines charges).

General Comment on Embedded Generation within this Report

Capital costs used in this report for the various electricity generation options are those associated with the appropriate level of grid-connection. These and other factors have been fed into the cost supply curves.

Conclusions about uptake based on the cost supply curves are complicated by grid level considerations. Uptake will not be a simple matter of observing the next cheapest unit cost generation option. Where generation is reliable and dispatchable (as in the case of geothermal energy, as opposed to wind or, to a lesser extent hydro) a small Transpower benefit from reduced connection charges may be passed through by network companies, and possibly other benefits from avoided network costs. At the smallest scale (say in a home or factory), for a retail company offering a fully variable-based tariff, the generation may avoid the full retail tariff.

Thus, as an extreme case, it may be possible for a home or factory-based generation option at 12c/kWh to be rationally implemented prior to generation options feeding the national grid or a local network company at 6c/kWh.

In practice the distributed generator could gain a benefit from the network operator, could gain no benefit, or could be charged for use of the network.

As a consequence, the uptake of renewable generation will be a strong function of the network companies' desire to accept (and both the network and retail companies willingness to promote) distributed/embedded generation through appropriate tariffs and/or investment.

APPENDIX D: RESOURCE DEVELOPMENT COSTS

Electricity Costs

All projections in this report are based on generic costs, or cost estimates which have been published previously. As projections, they are subject to considerable uncertainty (±30% would be expected for any one project). However, because these estimates are based on past developments, they have been checked with industry trends, and are across many projects, the overall result is considered to be reasonable.

Capital costs are discussed in the resource reports. A wide range of cost sources has been consulted. Values associated with most confidence have been converted into New Zealand dollars of the time of the estimate. These have then been escalated to current dollars, frequently using the Cost of Construction Index (CCI). This is considered a reasonable escalator for electricity options.

Note that there is some uncertainty in the scope of which costs should reasonably be included for some resources. In the case of landfill gas, the facilities for landfill gas collection may largely be expected to be a cost against the landfill for flaring purposes. Generation costs have been included with and without these collection costs.

Renewable energy options can have a high imported cost component that will be subject to exchange rate movement. These, in turn will be affected by the dominant currency of the primary source of equipment or materials, frequently that of Europe, Japan or the United States. The MED modelling allows for a NZ$/US$ conversion. As a rough approximation relative movement of other exchange rates has been similar. For the current year, the exchange rate is taken to be NZ$1=US$0.42, but it is assumed to rise to NZ$1=US$0.50 by 2006. Table D1 shows the proportion of both capital and Operations and Maintenance that will be sensitive to the exchange rate.

Table D1: Influence of Exchange Rate on Estimates

Resource	Capital Cost Percentage Affected by Exchange Rate	O&M Cost Percentage Affected by Exchange Rate
Biomass	75	60
Geothermal	70	70
Hydro	35	25
Solar (Photovoltaic)	45	0
Wind	80	40

Table D2, based on the discussion in the resource reports, shows the assumed relationship between generator size and capital cost for each technology.

Operations and maintenance costs have been estimated on a similar basis. Frequently, O&M has been expressed as a percentage of capital, and this has been found to give reasonable results at this level of study.

Table D2: Cost Estimates for a Range of Resources

Resource	Capital Cost Estimate	O&M Estimate
Hydro	Highly variable - no clear size relationship - typical current costs \$1,500-\$8,000/kW, mean cost \$3,600/kW	About \$15/kW/year.
Geothermal	Plant is modular with economies of scale (25MW plant currently at \$3,200/kW, 50MW plant at \$3,000/kW). These can be partly offset by presence of existing Crown wells. Binary plant is more expensive.	Station/steamfield O&M about \$93/kW/year for stations >50 MW. "Fuel" costs are included in the capital and O&M figures above.
Wind	Typically current specific cost is around \$2,000/kW and largely independent of size due to modular nature	O&M Fixed \$28/kW/year and variable \$0.006/kWh.
Biomass (Woody)	Technology is assumed to be Atmospheric Biomass Gasification Combined Cycle. Electricity cost in 2012 (\$/kW) = 8,950 x $MW^{-0.2673}$ Electricity cost in 2025 (\$/kW) = 7,360 x $MW^{-0.2673}$	O&M 5% of capital/year.
Biomass (Landfill Gas)	If collection costs are included current specific cost is \$2,250/kW. If they are excluded, cost is \$1,500/kW	O&M \$70/kW/year.
Biomass (Other)	These costs are not discussed as they are excessive.	
Solar Hot Water Heating	Capital costs are dropping. Equivalent to \$2,500/kW by 2012	O&M \$35/unit/year.

Capital and O&M estimates have been used to give unit costs of electricity. Other major assumptions feeding into the unit cost models are outlined in Table D2 below. Experience has been used in assessing the relative split of mechanical, civil and other costs, and applying appropriate depreciation rates to these. Note that models have been run with a weighted average cost of capital (WACC) set at 5% and 10% as requested by the Ministry of Economic Development.

Table D2: Major Assumptions within the Unit Cost Models

Resource	Life (yrs)	Conversion Efficiency	Load Factor	Construction Periods (yrs)	Fuel Cost
Hydro	50	-	Varies average 56%	Sites specific but typically 2-4	-
Geothermal	30	10%	>90%	1.5	-
Wind	20	-	Varies below 50% - lower for lower wind speeds	1	-
Biomass (Woody)	25	33->40% for gasifier. Efficiency (%) = 29 x $MW^{0.092}$	85%	1	See text for fuel blend costs. Costs range from process residue at $0.25/GJ to cuttings plus arisings fuel at $3.4/GJ.
Biomass (Landfill Gas)	15	18%	90%	1	-
Biomass (Other)	25	25-30% for digester 30-48% for gasifier	90% 80%	1	Zero for waste $1.5/GJ for gasification
Solar Hot Water	20	35-45%	NA	-	-
Photovoltaic	25	15%	17-20%	-	-

The unit costs used in this study are levelised unit costs for each project life. For a project this unit cost is derived by taking the present value of costs, i.e. capital, O&M, tax, depreciation (including tax benefits of depreciation), fuel (where applicable), and dividing it by the present value of the kWhs generated over the lifetime of the project. No revenue stream is included in this calculation.

Both capital and other costs are normally presented as an annual figure for each category. In theory, while generation can be defined for each quarter, it is usually entered apart from the commissioning phase, as an averaged figure.

Apart from capital costs, O&M costs, fuel costs, kWhs generated, and project lifespan, a number of other factors influence the levelised unit cost. Two of these are the discount rate (assumed to equate to the WACC) and the timing of construction expenditure relative to commissioning.

The modelling inputs do not directly include any project debt/equity or gearing, nor interest rate on debt. These parameters are considered to be input into the overall discount rate or WACC to be applied to the project.

Some enhancements or variations to the concept of project specific models have been used for particular technologies.

Hydro, with no “fuel” costs and a very low O&M level relative to capital costs can be represented by a yield to cost ratio (YCR) of say GWh pa/$m capital cost. From a range of over 45 projects an algorithm depicting the relationship between the YCRs and unit costs has been established for a particular WACC. As YCR is easily established for each project/opportunity a corresponding unit cost can be calculated. Projects that are considered to differ significantly from the normal, e.g. a very extended construction/commissioning period are individually modelled.

In the case of wind, an algorithm defining the relationship between average windspeed and load factor (also known as net capacity factor) has been created. Given a standard MW windfarm size, and a selected capital cost, the unit cost has been calculated using the windspeed as the input rather than a load factor.

A comprehensive set of estimates for each WACC and confidence level has been derived and is given in the resource reports. These have been used to develop the cost supply curves.

Heat Plant

Heat Plant costs have been developed on a similar basis to electricity costs.

Table D4: Influence of Exchange Rate on Estimates

Resource	Capital Cost Percentage Affected by Exchange Rate	O&M Cost Percentage Affected by Exchange Rate
Geothermal	70	70
Biomass	75	60

[Barrie, I have a doubt about the graph that comes from this for biomass. Can you double check that the factor above has been multiplied by the exchange rate ratio]

Table D5: Cost Estimates for a Range of Heat Plant

Resource	Capital Cost Estimate (2002)	O&M Estimate
Geothermal	For steam flow, F(t/h) F<12.5 Cost ($M)= 9.3+0.035F 12.5<F<37.5 Cost($M)= 7.4+0.19F F>37.5 Cost ($M)= 5.1+0.25F	O&M 5.5% of capital /year
Biomass (Woody)	Cost ($/kW) = 913 x $MW^{-0.23}$	O&M 5% of capital /year

The following were inputs into the unit cost model.

Table D6: Major Assumptions within the Unit Cost Models

Resource	Life (yrs)	Conversion Efficiency	Load Factor	Construction Periods (yrs)	Fuel Cost
Geothermal	20	NA	87%	1	-
Biomass	25	70%	85%	1	Arisings $2.7/GJ Arisings (incl. Cutover) $3.4/GJ Process residue $0.25/GJ Plantation Fuelwood $6.5/GJ Firewood $2.6-25.5/GJ

APPENDIX E: ASSESSMENT OF FOSSIL-FUELLED HEAT PLANT COSTS

The potential for renewable energy heat plant to displace existing fossil-fuelled heat plant is determined by the relative delivered cost of heat after conversion. The following appendix outlines the derivation of fossil-fuelled heat plant costs used in comparisons.

Generally, fuel costs are of a confidential nature, though pricing methodologies in the gas sector is available on the web. For coal, a rough order assessment was based on the possible mine costs and associated transport costs from mining centres in the Waikato, West Coast, Otago and Southland. Where possible, these costs have been crosschecked against known market costs.

On this basis, a spread of fuel costs for industrial customers is expected across both islands, with costs generally being greater with distance from source. The price range is summarised in Table E1.

Table E1: Approximate Range of Fossil Fuel Prices

Fuel	Location	Price Range
Coal	South Island	$2-4/GJ
	North Island	$3-5/GJ
Gas	North Island	$4-10/GJ

Heat plant costs have been published and have been escalated for this report. Costs have been checked against other databases. O&M has been assumed to be 5% of capital per year. Capital costs are summarised in Table E2.

Table E2: Capital Cost Estimates for Heat Plant (2012/2025)

Fuel Source	Size Range	Cost Formulae
Coal	<7.5 MWth	Cost ($M) =1.25 + 0.0597 * MW
	>7.5 MWth	Cost ($M) = 1.83 + 0.0564 * MW
Gas	<12 MWth	Cost ($M) = 0.123 + 0.0418 * MW
	>12 MWth	Cost ($M) = 0.812 + 0.0468 * MW

Unit cost calculations were then carried out with similar assumptions as per biomass heat plant. A conversion efficiency of 80% was assumed for coal and 75% was assumed for gas. These calculations are based on an 85% load factor. The resulting calculated unit costs (in terms of $/GJ of delivered heat) were subsequently approximated by power functions as shown in Table E3 and shown in Figure E1.

1 Zoellner, S (1991) *Cogeneration in New Zealand Report No 1 Introduction and Economics.* For Ministry of Commerce, March 1991

Table E3: Assessed Delivered Heat Cost (2012/2025)

Fuel Source	Case	Heat Formulae
Coal	South Island Low	Cost ($/GJ) = 6.2395 * $MW^{-0.1859}$
	South Island High	Cost ($/GJ) = 8.6336 * $MW^{-0.1214}$
	North Island Low	Cost ($/GJ) = 8.9592 * $MW^{-0.1875}$
	North Island High	Cost ($/GJ) = 11.345 * $MW^{-0.1319}$
Gas	North Island Low	Cost ($/GJ) = 5.8174 * $MW^{-0.0081}$
	North Island High	Cost ($/GJ) = 14.357 * $MW^{-0.0869}$

Figure E1: Assessed Delivered Heat Cost (2012/2025) (10% WACC)

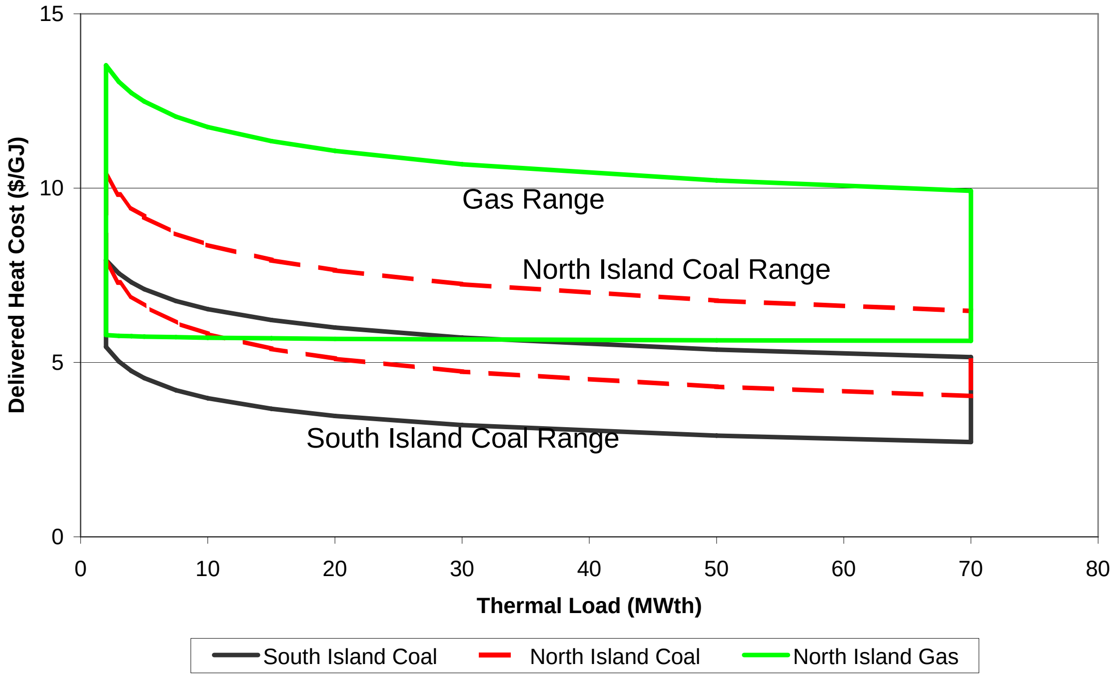


Figure E1 shows the range of delivered heat costs for various fuels i.e. the unit cost including fuel cost, capital recovery, O&M, etc.

It was found that fuel costs dominate the calculations such that they were relatively insensitive to WACC.

The coal costs (for the North Island) are consistent with a target heat cost range of $5-8/GJ sometimes quoted by Massey University's Centre for Energy Research.

There is a significant difference between South Island and North Island coal-fired heat. This could make displacement of South Island coal by renewables more difficult, especially given that woody biomass is the only alternative.

Significantly, a large premium (possibly 50% more) can be paid for gas-fired heat versus coal-fired heat. Reasons for this may include:

- Lower initial capital investment for gas
- Higher WACC/lower payback period actually required by businesses
- Convenience of gas with respect to supply and handling
- Less land is required for stores, fuel handling and for heat plant itself
- Clean nature of gas supply

- Perceived environmental benefits of gas over coal in terms of triple bottom line reporting (especially on the international scene).

With these points in mind, it would appear that woody biomass may be seen as a competitor to coal, but less so to gas. Where suitably located, geothermal energy may be able to displace some coal and a baseload portion of gas if delivered in a hassle-free manner to the consumer.