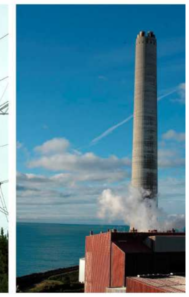
New Zealand's EnergyScape







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Transitioning to a Hydrogen Economy

Identification of Preferred Hydrogen Chains

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CRL Energy Ltd
SCION
INDUSTRIAL RESEARCH LIMITED
GNS SCIENCE TE PŪ AO
NIWA Taihoro Nukurangi

Transitioning to a Hydrogen Economy: Identification of Preferred Hydrogen Chains

CRL Energy Ltd

68 Gracefield Road,
PO Box 31-244
Lower Hutt
New Zealand
TEL +64 4 570 3700
FAX +64 4 570 3701
www.crl.co.nz

CHRISTCHURCH OFFICE
77 Clyde Road
PO Box 29-415
Christchurch
New Zealand
TEL +64 3 364 2768
FAX +64 3 364 2774

GORE OFFICE
41 Irk Street
Gore
New Zealand
TEL +64 3 208 7216
FAX +64 3 208 7107

HAMILTON OFFICE
C/- Ruakura Research Centre
Private Bag 3123
Hamilton
New Zealand
TEL +64 7 838 5261
FAX +64 7 838 5252

WEST COAST LABORATORY
43 Arney Street
PO Box 290
Greymouth
New Zealand
TEL +64 3 768 0586
FAX +64 3 768 0587

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This report was compiled by Tony Clemens, Martin Garrood and Tana Levi of CRL Energy Ltd, and Alister Gardiner of IRL.

Executive Summary

This report to stakeholders is the second output from the FRST project "Transitioning to a Hydrogen Economy". The project aims to identify how hydrogen could become a significant contributor to New Zealand's energy system in the future and the role of research investment in realising that future. Details of the project stages and process are outlined in the Introduction.

This report covers Stage 2, where 24 hydrogen energy chains ("chains") were analysed using an economic, emissions and energy (E3) model, developed for the European "HyWays" project, in order to select those most likely to feature during the transition to, and subsequent operation of, a fully developed NZ hydrogen energy system. The 24 candidate chains were selected, after consultation with targeted end users during Stage 1, as potential contributors to a hydrogen economy in New Zealand. The feedback arising from the consultation process is included as Appendix A of this report.

The analysis led to the selection of nine preferred hydrogen chains. During the selection process two types of end use application were considered – transport and stationary. At the end point of each transport application chain the hydrogen was fed into a fuel cell or ICE vehicle. For the stationary applications it was fed to a fuel cell for distributed generation of combined heat and power. Reference chains for transportation using existing fossil fuel options (petrol and diesel) were modelled for comparison to the hydrogen-fuelled transportation options and reference chains modelling the existing provision of electricity and heat from the grid electricity mix were modelled for comparison to distributed generation and CHP hydrogen chains.

The chains selected to go forward for specific scenario modelling under New Zealand conditions were:

Chain Number	Feedstock	Hydrogen Production Method	CCS	Hydrogen Transport Method	End Use
Chain 2a	Natural gas	Central Reformation	No	Tanker	Transport
Chain 3a	Natural gas	Central Reformation	Yes	Pipeline	Transport
Chain 7a	Coal	Central Gasification	Yes	Pipeline	Transport
Chain 9c	Biomass	Central Gasification	No	Pipeline	Stationary
Chain 10a	Biomass	Central Gasification	No	Tanker	Transport
Chain 13a	Wind electricity	Central Electrolysis	N/A	Pipeline	Transport
Chain 16a	Grid electricity	Central Electrolysis	N/A	Tanker	Transport
Chain 17a	Wind electricity	Refuelling Site Electrolysis	N/A	Direct Use	Transport
Chain 22a	Natural Gas	FC CHP with reformation	No	Direct Use	Stationary

Selection of Transport Application chains.

One of the outputs from the E3 modelling process used in the selection process was CO_2 emissions. For transport, which is where the hydrogen economy could make its largest impact in reducing GHG emissions, the two chains involving hydrogen production from coal without CCS, showed similar emission levels to present day vehicles running on petrol. All other hydrogen chains showed substantial reductions in emission levels over this base case and also over cases involving foreseeable improvements in diesel and diesel hybrid vehicle technology. Natural gas reformation without CCS and grid electricity mix electrolysis all reduced emissions to around 50% of those associated with the base case. Hydrogen production from fossil sources with CCS and from renewables all showed very low emission levels relative to the base case. Two chains, both involving biomass with CCS showed substantial negative CO_2 emissions.

The two other key outputs from the E3 modelling process used for chain selection were primary energy consumption and costs. For transport applications these were assessed in kWh primary energy use / vehicle-km and \$/vehicle-km respectively. The CO_2 emissions data was converted to a carbon cost ranging from \$0 to \$100 per tonne and added to the baseline fuel costs for each chain to produce a two-dimensional plot of energy use against costs.

A major conclusion from the transport analysis was that in terms of both energy use (or "well to wheels" efficiency) and cost, the feedstock used was more important than the details of the chain which include options relating to CCS and carbon tax, type of production plant, hydrogen delivery option (pipeline or truck) and distance delivered. Overall energy use for natural gas and wind electrolysis chains was low compared with solid fuels such as coal and biomass. On the other hand, the overall cost of production from electrolysis was high compared with direct reformation and gasification routes from thermal fuels. At a first pass, hydrogen production from natural gas appeared most promising but in recognition of the need for long term security of supply, it was deemed prudent to include a mix of chains involving fully renewable resources (biomass and wind), increasingly renewable resources (grid electricity) and large natural resources (coal, e.g. Southland lignite).

The majority of the transport chains chosen (2a, 3a, 7a, 10a, 13a, 16a) were based on the most cost effective long term options. They involve centralised hydrogen production and large scale delivery and usage infrastructure. To evaluate early market transition costs, a forecourt production chain involving wind electrolysis (17a) was selected. It was chosen in preference to a natural gas reformation chain, due to its zero GHG footprint and the uncertainty of future gas supplies.

Selection of Stationary Application Chains:

Use of hydrogen within stationary fuel cells is unlikely to have a major impact on global energy emissions but, by facilitating the early adoption of fuel cells, was seen as an important transition pathway to a full hydrogen infrastructure. The reference case for stationary chains was taken to be the use of grid mix electricity in an efficient end use process. In terms of CO_2 emission levels the only large scale centralised hydrogen production chains, apart from biomass with CCS, to show improvement over the reference case were wind electrolysis and thermal fuels with CCS. High efficiency combined heat and power (CHP) from small distributed generators using thermal fuels such as natural gas and LPG (without CCS) also showed substantial reduction in CO_2 emissions (~50%).

The primary energy consumption and costs of stationary hydrogen-fuel cell chains were expressed as kWh primary energy use / kWh heat+electricity out and \$/kWh heat+electricity out. As for analysis of transport application chains, carbon emissions were converted to a cost using a carbon tax range of 0 to 100NZ\$/tonne.

The results showed that in most cases the costs were higher than the reference case suggesting that centralised hydrogen production for stationary uses in distributed fuel cells on the large scale is unlikely to be deployed until carbon constraints or cost increases occur within the existing electricity infrastructure. As seen for CO_2 emission reductions, the most promising stationary chains, because of their improved "source to use" efficiency over the standard grid case, were those involving "appliance level" natural gas/LPG CHP fuel cells. Unless there is some substantial benefit from storing the energy as hydrogen it is unlikely that electrolyser based production will be used for these applications where grid mix electricity is available. However hydrogen produced from other resources and supplied via a transport infrastructure for on-site fuel cell CHP generation also appears feasible as a longer term stationary option.

The main message from the stationary analysis was that thermal fuel use and GHG emissions could be reduced by using these fuels directly in hydrogen FC CHP appliances instead of either generating electricity from central locations (and wasting the heat) or converting to hydrogen and then transporting it for CHP – hence the selection of Chain 22a. In the longer term, if centralised production of hydrogen from biomass becomes an accepted part of the transport infrastructure, stationary use of this hydrogen becomes feasible and may be worthy of further investigation – hence the selection of chain 9(c).

In Stage 3, the nine selected chains will be subjected to scenario analysis. Stella modelling will be used to identify the contribution profiles of each of the hydrogen chains under different transition scenarios. These range around 50% of the transport fleet being hydrogen powered by 2050 and up to 20% of the domestic and commercial energy being provided by stationary CHP fuel cells. Sensitivities will be tested to establish relative importance of various factors associated with uptake.

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GLOSSARY

CCS	Carbon Capture and Storage (or Sequestration)
CGH2	Compressed Gaseous Hydrogen
CHP	Combined Heat and Power
E3	A database used to assess Energy use, Economics and Emissions for processes
FC	Fuel Cell
FCV	Fuel Cell Vehicle
GHG	Greenhouse Gas
ICE	Internal Combustion Engine
ICEV	Internal Combustion Engine Vehicle
IGCC	Integrated Gasification Combined Cycle
LPG	Liquefied Petroleum Gas
PHEV	Plug-in Hybrid Electric Vehicle
SMR	Steam Methane Reformation
USDoE	United States Department of Energy
NZBCSD	New Zealand Business Council for Sustainable development
NZES	New Zealand Energy Strategy
NEECS	National Energy Efficiency and Conservation Strategy
CCT	Carbon Capture and Trade

1 Introduction

This report to stakeholders is the second output from the FRST project "Transitioning to a Hydrogen Economy" [1]. The project aims to identify how hydrogen could become a significant contributor to New Zealand's energy system in the future and to develop a comprehensive understanding of what New Zealand needs to achieve in order to prepare for this eventuality; in particular the role of research investment in this process. At the end of the project New Zealand will have taken a number of steps towards developing a harmonised vision for transitioning to a hydrogen economy, will have identified the existing knowledge gaps and New Zealand specific barriers to transition together with the means to tackle them, and will have identified which of these means should be addressed from within New Zealand and which are most likely to come from outside.

The project consists of 5 Stages: Stage 1, the identification of potential energy supply chains using hydrogen as an energy carrier; Stage 2, energy, emissions and economic analysis of the potential supply chains to select a smaller number of preferred options for the forecast New Zealand situation; Stage 3, the integration of the various preferred supply chain options to meet a number of future implementation scenarios; Stage 4, the identification of the gaps and barriers in understanding or in resources to meet the developed scenarios; and Stage 5, development of a plan to address these gaps and barriers.

At the end of Stage 1, stakeholders were supplied with a document entitled, "Transitioning to a Hydrogen Energy Economy: Issues Document". This document was designed to raise awareness and understanding among government and industry stakeholders by providing information on the use of hydrogen for energy purposes under the following headings:

- What a hydrogen energy system is and the drivers for it.
- What the major issues relating to hydrogen production, storage, utilisation, codes and standards and public outreach are.
- What international and national research activities are being undertaken to address these issues.
- The extent of the present hydrogen market in New Zealand.

Hundreds of potential hydrogen energy chains were considered and prioritised using a first pass assessment process based primarily on sustainability, cost effectiveness of feedstock, status of conversion technology and relevance to New Zealand. This led to selection of 24 chains, covering a wide spectrum of possible options. Each was a complete chain from energy feedstock to end use encompassing every energy source available in NZ, hydrogen production technologies, hydrogen delivery options, and hydrogen end uses both for stationary and transportation use. Stakeholders were requested to comment on the proposed chains and identify any chains they felt should be added or deleted from the list. This feedback is collated in Appendix A of the present report and interspersed with responses from the project team.

In summary of this feedback, although objections were raised by individual stakeholders to particular chains, there was no agreement between stakeholders as to any particular chains that should be omitted or altered. Likewise, no extra chains were identified for inclusion into the list.

In Stage 2, these 24 chains (Table 1) were analysed using, an economic, emissions and energy (E3) model developed for the European "HyWays" project [2] to identify a small number of preferred hydrogen energy chains most likely to feature during the transition to, and subsequent operation of, a fully developed NZ hydrogen energy system. The results were compared with those from E3 modelling of reference chains used within the existing NZ energy system. The results of this Stage are presented in this document.

The next stage of the project is a "transition analysis" during which the conditions and timescale for establishment of a NZ hydrogen energy system under various plausible scenarios are modelled. This highlights the mix of supply chains that could be employed and how the mix varies over time. The fourth stage will then identify the knowledge gaps and New Zealand specific barriers to transition and the fifth, and final, stage of the process will involve production of an action plan to address these barriers most efficiently. An initial assessment of knowledge gaps is included in Section 3.4 of this report.

2 E3 Modelling of 24 Hydrogen Chains

2.1 Assumptions used in E3 Modelling

The 24 hydrogen supply chains from Stage 1 of the project, Table 1, were modelled using the E3 database developed for the European "HyWays" project [2]. The data for modelling each element in the production chains were obtained from numerous sources. It was found that much of the data used in the "HyWays" E3 database [2] was also suitable for the present programme.

To model each chain a specific location for the feedstock, hydrogen production plant and hydrogen demand centre were required. It was envisaged that the main demand centre would be Auckland through the transition phase and into a fully functional hydrogen economy, because of the size of the energy demand there. To enable initial comparison of feed stocks on a fairly level playing field only those from the North Island were considered in this analysis. The effect of transport distances is an output of the E3 model and so the sensitivity to feedstock position relative to demand centre can be easily determined in a sensitivity analysis. Conceptual hydrogen production facilities were positioned to minimise the effects of transport for the overall chain. For example, for low energy density woody biomass, which is difficult to transport, the production facility was sited next to the biomass resource and the hydrogen transported to the demand centre, whereas for natural gas, which is more easily transported than biomass, the production facility was situated just outside the demand centre and the natural gas piped to it. Again this resulted in specific distances of hydrogen transportation for each chain; the effects of placing the hydrogen production facility elsewhere could be separated in the E3 output and used to model the sensitivity of the results to production facility placement.

Two types of end use application were considered – transport and stationary. Transport applications were seen as the main driver for a hydrogen economy, particularly for private vehicle uptake. At the end point of each transport application chain the hydrogen was fed into a fuel cell or internal combustion engine vehicle. The transport chains do not include vehicle costs but do allow for fuel cost and engine efficiency. In the case of fuel cell vehicles this was set at 94 MJ/100 km [3], or 26kWh/100km.

For the stationary applications the hydrogen was fed to either a fuel cell for distributed power generation or to a micro-scale combined heat and power (CHP) fuel cell. A micro-scale CHP fuel cell is essentially a high efficiency household appliance that runs on conventional distributed fuel such as natural gas or LPG with the hydrogen being produced on-site and used in an integrated fuel processor. The stationary application chains were included because they are seen as a possible technology for use in the transition stage to a full hydrogen economy - a transition that may last for several decades.

Reference chains for transportation using existing fossil fuel options were modelled for comparison to the hydrogen-fuelled transportation options. The fossil fuel considered was an oil feed stock originating in the Middle East and delivered to New Zealand Marsden Point Refinery via a super tanker. As with chains 1 – 24 Auckland was assumed to be the demand centre. The end points for these transport reference chains were current diesel and petrol vehicles, a fuel efficient diesel vehicle and a hybrid diesel vehicle with engine and powertrain efficiencies as derived in the European CONCAWE study [3]. Similarly, reference chains modelling the existing provision of electricity and heat were modelled for comparison to distributed generation and CHP hydrogen chains. In these instances the electricity was obtained from the national grid, transmission and distribution losses were accounted for and the end user was again assumed to be located in Auckland.

Details of the 24 chains plus the reference chains and the assumptions made for each chain are given in Appendices B and C.

Table 1. Chains Selected for E3 Modelling

Chain Codes	Feedstock	Conversion Process	Distribution	End Use
1a - d	Natural gas	Central reformation	Pipeline	a) FC vehicle b) H_2 ICE vehicle c) Small-scale FC CHP d) Distributed power FC
2 a - d	Natural gas	Central reformation	Tanker	a) FC vehicle b) H_2 ICE vehicle c) Micro-scale FC CHP d) Distributed power FC
3 a - d	Natural gas	Central reformation + CCS	Pipeline	a) FC vehicle b) H_2 ICE vehicle c) Micro-scale FC CHP d) Distributed power FC
4 a - d	Natural gas	Central reformation + CCS	Tanker	a) FC vehicle b) H_2 ICE vehicle c) Micro-scale FC CHP d) Distributed power FC
5 a - d	Coal	Central gasification	Pipeline	a) FC vehicle b) H_2 ICE vehicle c) Micro-scale FC CHP d) Distributed power FC
6 a - d	Coal	Central gasification	Tanker	a) FC vehicle b) H_2 ICE vehicle c) Micro-scale FC CHP d) Distributed power FC
7 a - d	Coal	Central gasification + CCS	Pipeline	a) FC vehicle b) H_2 ICE vehicle c) Micro-scale FC CHP d) Distributed power FC
8 a - d	Coal	Central gasification + CCS	Tanker	a) FC vehicle b) H_2 ICE vehicle c) Micro-scale FC CHP d) Distributed power FC
9 a - d	Biomass	Central gasification	Pipeline	a) FC vehicle b) H_2 ICE vehicle c) Micro-scale FC CHP d) Distributed power FC
10 a - d	Biomass	Central gasification	Tanker	a) FC vehicle b) H_2 ICE vehicle c) Micro-scale FC CHP d) Distributed power FC
11 a - d	Biomass	Central gasification + CCS	Pipeline	a) FC vehicle b) H_2 ICE vehicle c) Micro-scale FC CHP d) Distributed power FC
12 a - d	Biomass	Central gasification + CCS	Tanker	a) FC vehicle b) H_2 ICE vehicle c) Micro-scale FC CHP d) Distributed power FC

Chain Codes	Feedstock	Conversion Process	Distribution	End Use
13 a - d	Wind generated electricity	Central electrolysis	Pipeline	a) FC vehicle b) H_2 ICE vehicle c) Micro-scale FC CHP d) Distributed power FC
14 a - d	Wind generated electricity	Central electrolysis	Tanker	a) FC vehicle b) H_2 ICE vehicle c) Micro-scale FC CHP d) Distributed power FC
15 a - d	Grid electricity mix	Central electrolysis	Pipeline	a) FC vehicle b) H_2 ICE vehicle c) Micro-scale FC CHP d) Distributed power FC
16 a - d	Grid electricity mix	Central electrolysis	Tanker	a) FC vehicle b) H_2 ICE vehicle c) Micro-scale FC CHP d) Distributed power FC
17 a - b	Wind generated electricity	Refuelling site electrolysis	None	a) FC vehicle b) H_2 ICE vehicle
18 a - b	Grid electricity mix	Refuelling site electrolysis	None	a) FC vehicle b) H_2 ICE vehicle
19 a - b	Natural gas	Refuelling site reformation	None	a) FC vehicle b) H_2 ICE vehicle
20	Coal	Central IGCC + H_2 gas turbine + CCS	Direct use	Electricity for grid
21	Biomass	Central IGCC + H_2 gas turbine	Direct use	Electricity for grid
22 a - b	Natural gas (piped)	FC CHP with reformation	Direct use	a) Micro-scale FC CHP b) Distributed power FC
23 a - b	LPG (by tanker)	FC CHP with reformation	Direct use	a) Micro-scale FC CHP b) Distributed power FC
2 4 a - b	Ethanol (by tanker)	FC CHP with reformation	Direct use	a) Micro-scale FC CHP b) Distributed power FC

2.2 Methodology for E3 modelling

The methodology is best considered by looking at a specific example:

Chain 1a was envisaged as gas being extracted from a natural gas field in Taranaki, transported 350km in a natural gas pipeline to a site just south of Auckland where it was converted to hydrogen in a central steam methane reformation plant very close to the natural gas main. Grid electricity was used for this process. From there the entire hydrogen gas stream was transported 20km through a large diameter hydrogen pipeline to central Auckland. A 5km small diameter hydrogen pipeline carried a portion of the hydrogen to a forecourt refuelling station. The hydrogen was then transferred to a fuel cell vehicle with compressed gas storage.

Chain 1b was exactly the same except the hydrogen was transferred to an ICE vehicle.

Chain 1c was exactly the same as chain 1a except that the 5km small diameter hydrogen pipeline carried a portion of the hydrogen to a micro FC CHP unit located at a residential or commercial site.

Chain 1d was exactly the same as chain 1a except that the 5km small diameter hydrogen pipeline carried a portion of the hydrogen to a larger but still local distributed power FC unit.

It should be noted that the E3 modelling process was carried out in 2 stages. The first stage calculated the energy use, CO_2 emissions and costs of the chain used for hydrogen production and delivery to a delineated end point: - in these cases the end of the small diameter 5km pipeline. This was unique to each production source. The second stage depended on application. It calculated the energy use, CO_2 emissions and costs for the four generic applications considered, which were either a refuelling station plus a FC or ICE vehicle, or two scales of CHP FC stationary power unit, and attached this to the end of the chains. This methodology was common to chains 1,3,5,7,9,11,13 and 15. For chains 2,4,6,8,10,12,14 and 16, the hydrogen was conveyed by tanker rather than pipeline. For chains 17 through 24 the hydrogen was produced at the point of usage. Chains 17 to 19 represent forecourt production for refuelling vehicles and chains 20 through 24 represent on-site production from infrastructure fuels for stationary fuel cell CHP. Chain 24 – ethanol - was included to assess the use of ethanol for stationary power since if it becomes available as a standard fuel, its use as renewable distributed fuel for stationary applications may be cost effective in the future.

2.3 Results for Transportation Chains

One of the outputs from the E3 modelling process was the whole supply chain CO_2 emissions. Figure1 shows the modelled emissions for the transport supply chains to a FC vehicle.

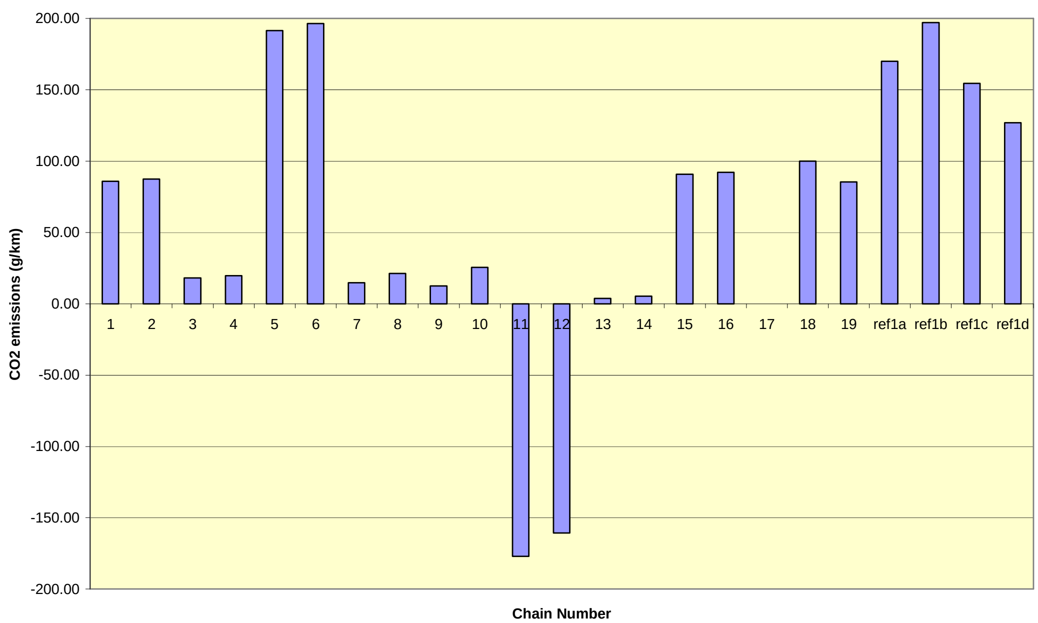

Figure 1 - CO_2 emissions for transport application chains

Emissions are given in terms of grams of CO_2 equivalent per km. (See Appendix D for the full results.) Chains 5 and 6, which involve hydrogen production from coal without CCS, showed similar emission levels to the reference chain 1b which involved present day vehicles running on petrol. All other hydrogen chains showed reductions in emission levels, with natural gas reformation without CCS (1, 2, 19) and grid electrolysis (15, 16, 18) all reducing emissions to around 50% of that of the reference chain for existing vehicles. The grid electrolysis cases were interesting in that the emission levels were perhaps not as low as one might expect relative to the reference chains. This was due mainly to the thermal fuel content of present electricity generation and the energy losses in production and transport of the hydrogen. On the other hand, if wind generated electricity was used for hydrogen production, (13, 14, 17) the GHG level was very low. As expected, the fossil sources with CCS (3,4,7,8) and renewables all showed very low emission levels. The two chains with negative emissions involve biomass with CCS. This may appear an unlikely combination at present, but a high carbon cost may make this chain attractive in the future.

Tables of the primary energy consumption, carbon dioxide emissions and costs (all on a per km basis) of the vehicle-km driven by utilising the hydrogen and reference chains are given in detail in Appendix D. To enable visualisation of these data in two dimensions the carbon dioxide emitted was converted to a cost using the concept of a carbon tax. This is one simple method for assigning a variable level of importance to greenhouse gas (GHG) emissions which may eventually become a reality for practically controlling GHG emissions. The range of carbon tax used was from 0 to 100NZ$/tonne carbon dioxide emitted. This was added to the baseline fuel costs for the chain and displayed as a range on graphs of energy use vs. cost.

Figure 2 does not include individual data points for each chain but shows regions into which fall the data points for a particular feedstock.. The exact positions of the data points for each chain are shown in Appendix D (Figure D1 to Figure D5). A major conclusion was that the feedstock used was more important (first order variable) than the details of the chain - including options relating to CCS and carbon tax, type of production plant, hydrogen transport option (pipeline or truck) and distance (second order variables).

The reference chain region (detailed in Figure D5) showed that substantial improvements are predicted in energy use and cost of existing ICE and hybrid vehicles as vehicle engines and technology become more efficient. The conventional gasoline fuelled ICE vehicles are at the top of the reference region, hybrid diesel vehicles are at the bottom.

Natural gas based hydrogen chains were the only ones that were competitive with the improved efficiency transport options in terms of both cost and use of primary energy. However all chains except those involving electrolysis were competitive with the existing vehicle technology reference case.

Coal and biomass options may be cost competitive with future fossil fuel transportation (depending on improvements) but used more primary energy relative to natural gas reformation mainly because of the energy use associated with gasifying the feedstock.

Electrolysis was more expensive, with that based on current grid electricity using more primary energy than electrolysis using wind generated electricity only.

The chains were modelled using current fuel prices and it may be, as crude oil prices increase and the reference chains become more expensive, that other energy prices will increase. However, the prices for some feedstocks may not be closely correlated to the price of crude oil and would rise more slowly, moving their position on the graph relative to the reference chains. If the ‘cost of carbon’ rose to high levels this would also give a cost advantage to wind generated electricity, biomass and gas/coal with CCS over the reference chains.

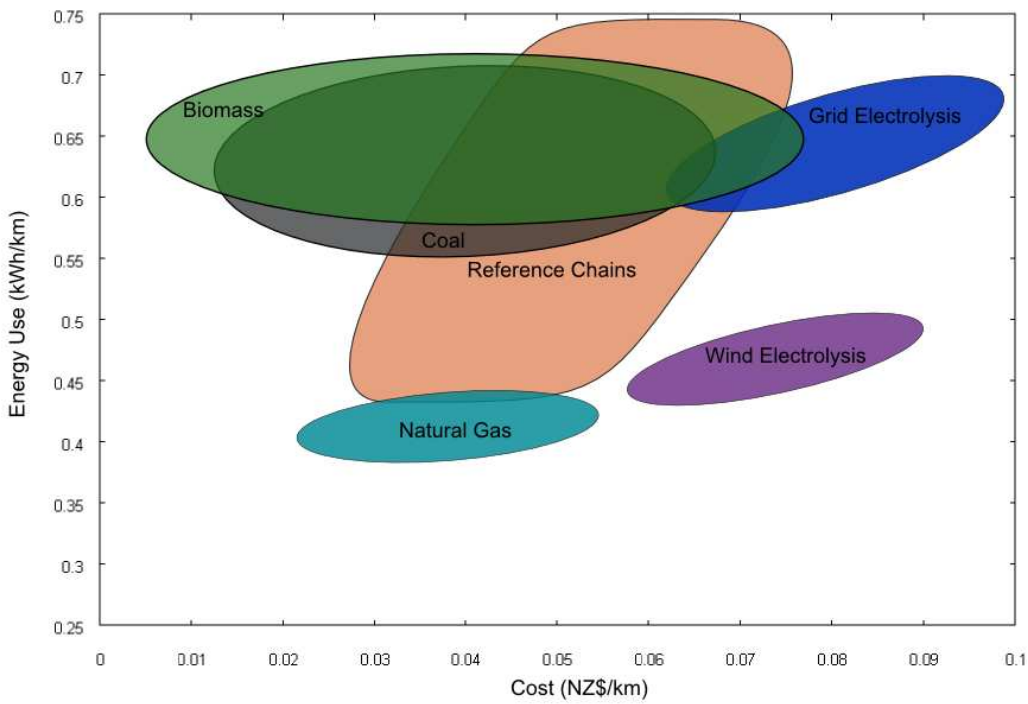

Figure 2 - Cost and Primary Energy Use of the Various Transport Chains per km

It should be noted that Figure 2 only includes the data for FC vehicles. If hydrogen fuelled ICE vehicles were shown, the relative positions of the feedstock related areas would remain the same but the reduced drive chain efficiencies and consequent increased energy use would shift each of the non-reference coloured areas up and to the right (by a factor of approximately 1.8 fold). This highlights the importance of durable and cost effective fuel cells to the uptake of a hydrogen economy. However the potential use of the hydrogen ICE as a transition technology should not be overlooked – especially if oil security or price become a major issue. It is a proven technology and vehicle costs would be little different from those of reference chain vehicles.

The use of hydrogen production technologies at the site of the refuelling station demarks the right hand side of the regions for the natural gas and two electrolysis groups. This is because smaller scale production is less efficient and uses more primary energy, but more significantly is more expensive in terms of capital investment and fuel costs.

The effect of the second order variables is shown schematically in Figure 3 for the case of coal as a feedstock. The point represents coal gasification without CCS with a carbon tax set to zero and a pipeline to move the hydrogen 100km to the demand centre at Auckland. The arrows radiating from that point show the individual effects of changing to hydrogen delivery by truck , addition of a $100NZ/tonne carbon tax and the inclusion of CCS.

Clearly, transport by pipeline is both cheaper and consumes less primary energy than the truck delivery option. They would be the preferred delivery method if demand was sufficiently high to merit their deployment. Adding a carbon tax increased the costs but had no effect on primary energy consumed. Utilising CCS increased costs and also used more primary energy but when combined with a high level of carbon tax the increase in costs could be compensated for by the reduction in costs of carbon emissions.

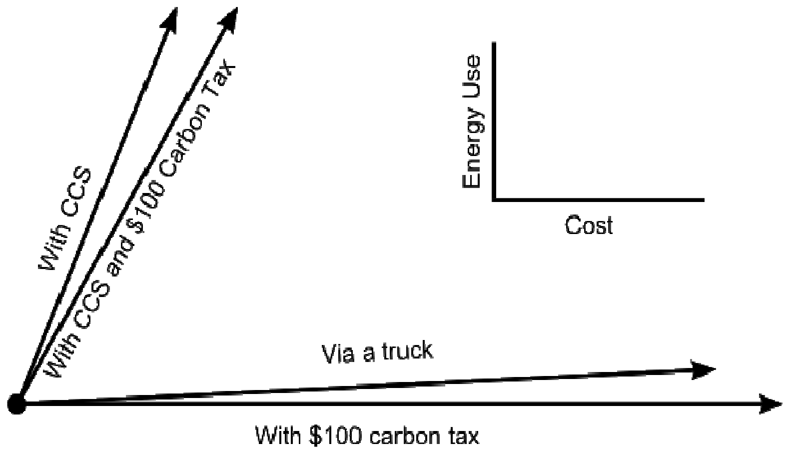

Figure 3 - Variation in Cost and Energy Use via Second Order Effects for Transport Chains

2.4 Results for Stationary (Heat and Electricity) Chains

Use of hydrogen within stationary fuel cells is unlikely to have a major impact on global energy emissions, but was seen as a probable transition pathway to a full hydrogen infrastructure, by facilitating the early adoption of fuel cells. For consistency, most of the central hydrogen production routes analysed for the transportation application were also considered for stationary chains, although many of these were unlikely. Emissions from stationary hydrogen chains in New Zealand must be compared against an already reasonably low-emission electricity system. The reference case for these chains was the use of grid mix electricity in an efficient end use process. Interestingly, this base case was not as green (in terms of low GHG emissions) as one might initially imagine, due to the substantial CO_2 emissions from the 30% or so share of electricity supply currently provided from thermal power plants.

Figure 4 shows the modelled CO_2 emissions for most of the stationary supply chains.

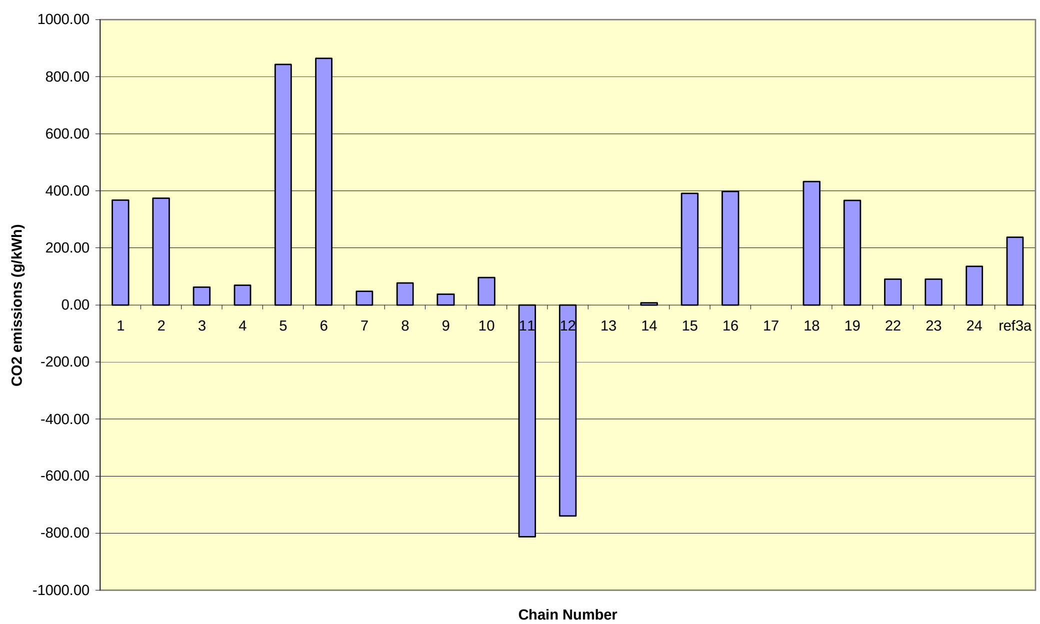

Figure 4. CO_2 emissions for stationary application chains

Emissions in this case are given in terms of grams of CO_2 equivalent per kWh used. (See Appendix D for the full results.) The grid reference case 3a consists of direct grid electricity to end use energy services and showed an emission level of 237gm/kWh.

On this basis, chains 5 and 6 which involve hydrogen production without CCS from coal and use in a distributed fuel cell showed emission levels significantly higher than the reference case. At the centralised hydrogen production level only wind electrolysis and thermal fuels with CCS showed improvement over the existing grid electricity, apart from the biomass with CCS chains which, as for the transport application, showed substantial negative CO_2 emissions.

The gas reformation chains (1 and 2) also showed higher emissions than the reference case but to a lesser extent. So too did the grid electrolysis chains 15, 16 and 18 because of energy loss in the electrolysis process and other factors. This strongly suggests that central electrolysis for stationary applications would only be useful if there was a need to store grid electrical energy via hydrogen. The wind electrolysis chain 17 showed negligible carbon footprint, and was representative of any renewable electricity source, in that it can be used to store electricity with a virtually zero carbon footprint. All other hydrogen chains showed improvements in emission levels over the reference case. As expected the fossil sources with CCS all showed very low emission levels.

High efficiency from "appliance level" micro combined heat and power (CHP) fuel cell systems or larger distributed CHP systems using thermal fuels such as natural gas and LPG without CCS showed substantial reduction in CO_2 emissions (~50%) as a result of relatively low fuel usage (chain 22).

The Government energy strategy goal of 90% renewable generation, if it is achieved, will progressively reduce the fossil fuel proportion of grid electricity mix and therefore the emissions attributed to each kWh generated - although due to demand growth this may not actually reduce total emissions. Generation via distributed fuel cells from clean hydrogen (using CCS if necessary) could have a future long term role in addressing GHG emissions should this become an imperative. It would, however, come at a cost.

Tables of the primary energy consumption, carbon dioxide emissions and costs of the heat/electricity per kWh used for hydrogen and reference chains are given in detail in Appendix D. Carbon emissions were converted to a cost using a carbon tax range of 0 to 100NZ$/tonne.

Figure 5 is analogous to Figure 2 for transportation but with primary energy use and cost shown per kWh of combined heat and electricity used, instead of per km travelled. The exact positions of the data points for each chain are shown in Appendix D (Figures D6 to D11). It can be seen that the regions for coal, biomass, natural gas and electrolysis are positioned similarly to each other in relative terms as they were in Figure 2.

Figure 5 showed that the provision of distributed heat and electricity by transporting hydrogen from centralised production from hydrocarbon sources and from a grid electricity mix using electrolysis was higher in both cost and primary energy use than the reference method, which along with the increased GHG emissions makes the use of centrally produced hydrogen unrealistic as a stationary power option at this stage.

The exception to this was the locally fuelled CHP fuel cell chains labelled "appliance" in Figure 5. Those operating on distributed infrastructure fuels such as natural gas and LPG occupied the bottom of the appliance area (Figure D 10) and had an energy use below that of the reference, and at a competitive price. Their GHG emissions were also low. This assumed that the combination of high efficiency heat and power offered by this chain (e.g. chain 22) was fully realised. The ethanol chain 24 occupied the top of the appliance area (Figure D 10) and showed a high energy input. This was due primarily to the inefficiencies associated with ethanol production from wood residues, and the substantial energy input to manufacture and refining. The E3 process chosen assumed that the ethanol production efficiency was 30% and that the process energy used was primarily fossil based. This is a substantial issue not only for hydrogen fuel cell use of ethanol, but even more so for conventional ICE vehicles operating on ethanol. It suggests their overall GHG footprint will be high, unless more efficient and greener methods of ethanol production are developed.

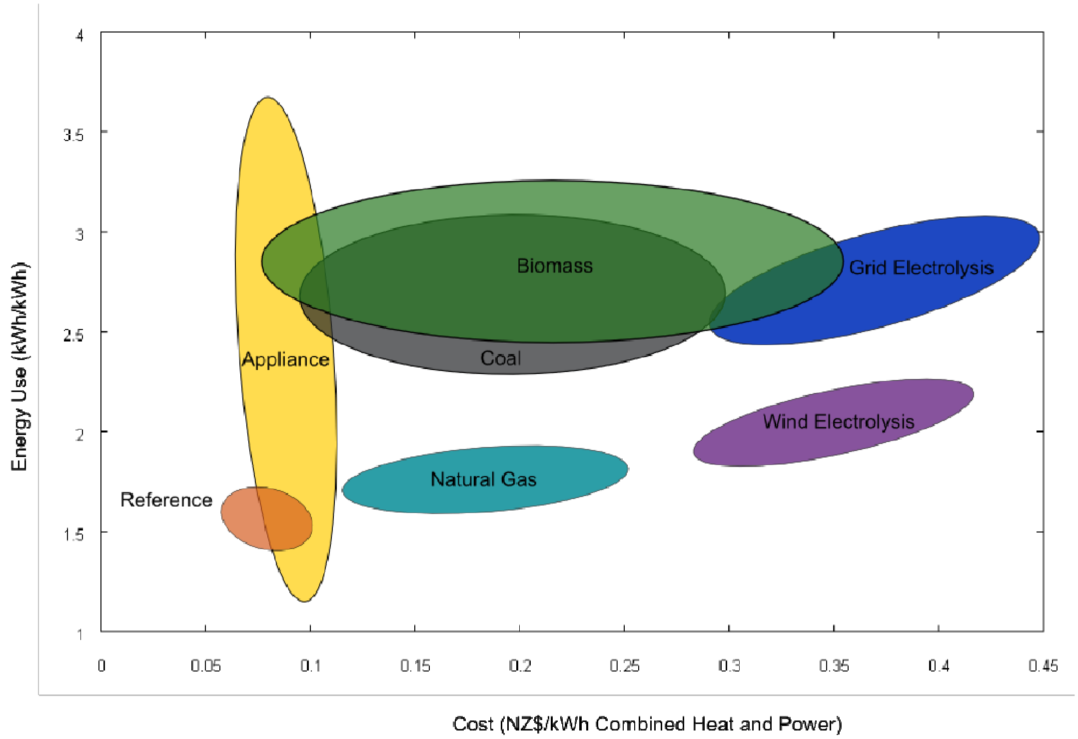

Figure 5 - Cost and primary energy for the various CHP Chains

Although these CHP options were not strictly hydrogen energy chains as hydrogen was produced and then immediately consumed within the appliance, they may pave the way for later use of hydrogen as a piped fuel to homes and businesses. It would be relatively simple to bypass the onboard reformer or delete it in later products and use an appliance fuel cell with hydrogen piped from a central production facility. This may occur in the longer term if hydrogen becomes the dominant pipeline fuel.

Chains 20 and 21 are special cases which involve centralised electricity production using a hydrogen gas turbine with no CHP. The results in Table D2 show that these technologies are not competitive at currently estimated costs with the grid electricity reference case (2a).

A possible future advantage of using hydrogen produced from biomass with CCS is that if carbon costs increased to a sufficiently high level then the cost of hydrogen produced may, because of the "carbon negative" nature of the process, be reduced to a similar level to that of the reference method. This suggests that the use of small-scale carbon capture from biomass resources with transportation to storage sites for combination with carbon dioxide from other sources warrants research as well as CCS on the large scale for fossil fuel plant.

The main message from the assessment of stationary applications was that thermal fuel use and GHG emissions could be substantially reduced by using these fuels directly in hydrogen FC CHP appliances instead of either generating electricity from central locations (and wasting the heat) or converting to hydrogen and then transporting it for CHP.

As for the transportation chains, feedstock was of major importance whereas the impact of secondary variables such as options relating to CCS, carbon tax, hydrogen transportation method and distance were less important. The situation shown in Figure 3 again applies.

Figure 6 presents the relative cost and energy use compared to the appropriate transport and stationary reference chains respectively. It can be seen that several of the transport chains (in black) already lie approximate to their reference chains, whereas the stationary chains, with the exception of the distributed fuel on-site reformation CHP options, where heat can also be used, were considerably removed especially in terms of cost.

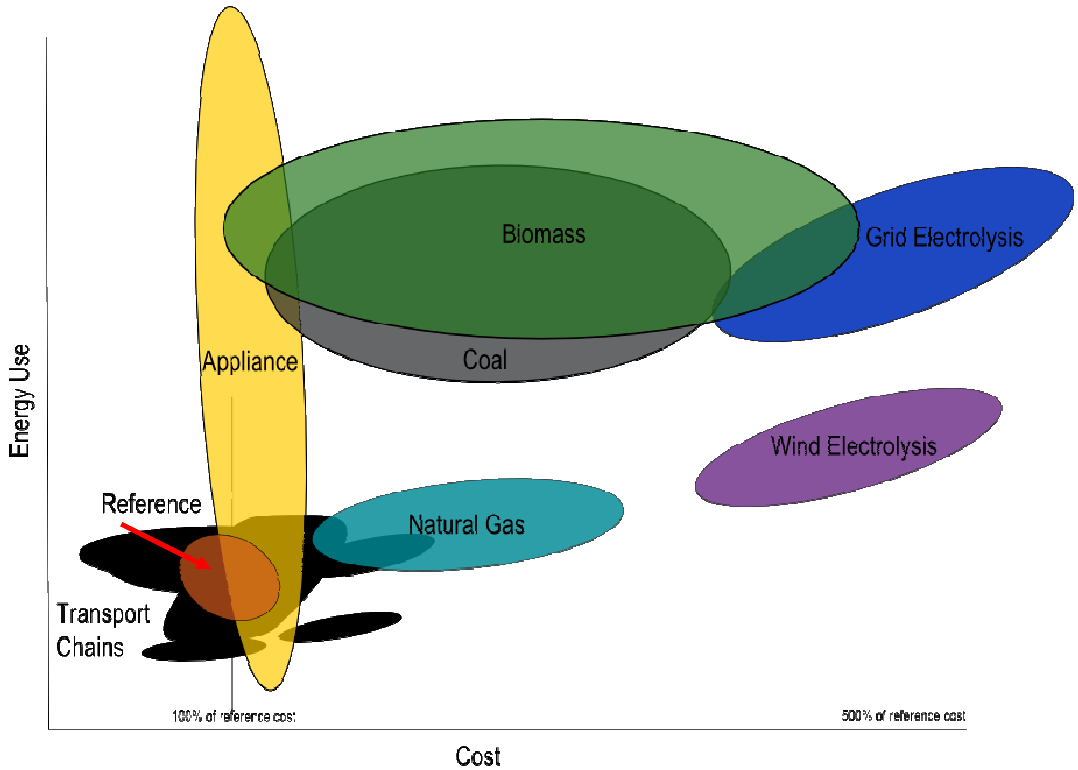

Figure 6 - Cost and primary energy for both the transport and the CHP chains.

2.5 Choice of Chains for Scenario Modelling

Transport:

From the comparison of transport options with the reference chains it initially seemed sensible to only include natural gas based chains for scenario modelling as they were competitive with the predictions for fossil fuelled based transport on both cost and primary energy use terms. However, the known reserves of natural gas in New Zealand are diminishing and it cannot be assumed that further large deposits will be discovered in the future (although it is a reasonable possibility with significant exploration of the Southern Basin for both oil and natural gas).

Long term, secure hydrogen supply is likely to be sourced from a mix of fully renewable resources (biomass and wind), largely renewable resources (grid electricity – currently 65-70% renewable but with the Government's aim to deploy only renewable generation in future this will increase), or large natural resources (coal e.g. Southland lignite).

The transition phase will most likely rely on resources/technology that are already fully developed such as natural gas reformation and electrolysis, with hydrogen transport by tanker until sufficient concentrated hydrogen demand is generated to merit pipeline installation. These options are also available in a wide range of scales and in particular electrolysis plant can be built up close to demand centres in a modular fashion to match increasing demand without the risk of building large plant with the associated risks of a hydrogen economy never developing. Coal gasification also offers some level of risk reduction in that the syngas product may be used for production of products (electricity, chemicals, natural gas, hydrocarbon fuels) that already possess a value.

Cost will also be an important factor in gaining public acceptance although exactly how feedstock prices will develop relative to reference fuel prices is neither clear nor trivial to predict. Scenarios requiring low carbon emissions will most likely require renewable feedstocks such as biomass, wind and grid electricity, or the fossil fuel options with CCS.

In light of the above considerations, options from each of the main feedstock types were selected to be used in the scenario modelling stage of the programme. This not only addressed security of supply issues in the event of no large scale discoveries of natural gas, but also allowed coverage of other scenarios such as minimising fossil fuel use, high costs of carbon reflecting increasing climate change importance or a future where CCS has limited success or applicability.

The majority of the transport chains chosen were based on the most cost effective long term options and therefore involved centralised hydrogen production and large scale delivery and usage infrastructure. However it is unlikely that such an infrastructure investment will be made spontaneously, and it is more likely that distributed "forecourt" hydrogen production will play a role during transition stages. Accordingly, a transitional chain was also selected. The wind electrolysis chain (17) was chosen over the natural gas chain (19) primarily because of the uncertainty around future gas supplies, and its zero GHG footprint.

Stationary:

From the results it was clear that centralised hydrogen production for stationary uses on the large scale is unlikely to be deployed until carbon constraints or cost increases occur within the existing electricity infrastructure. The most promising chains involved natural gas/LPG CHP fuel cells (chains 22 and 23) in that they showed substantially reduced emissions and improved efficiency over the standard grid case. Examination of the E3 data in Appendix D showed this to be due to the high CHP efficiency which resulted in low fuel use.

If centralised production of hydrogen from biomass becomes an accepted part of the transport infrastructure and it is widely distributed, stationary use of this hydrogen becomes feasible and worthy of investigation.

Consequently, two stationary options, chains 9c and 22a were also chosen as preferred chains for a hydrogen economy to go forward to the scenario modelling stage of the programme.

The nine preferred chains selected to go forward to the scenario modelling stage of the programme are shown in Table 2.

Table 2 - Chains Selected for Scenario Modelling

Chain Number	**Feedstock**	**Hydrogen Production Method**	**CCS**	**Hydrogen Transport Method**	**End Use**
Chain 2a	Natural gas	Central Reformation	No	Tanker	Transport
Chain 3a	Natural gas	Central Reformation	Yes	Pipeline	Transport
Chain 7a	Coal	Central Gasification	Yes	Pipeline	Transport
Chain 9c	Biomass	Central Gasification	No	Pipeline	Stationary
Chain 10a	Biomass	Central Gasification	No	Tanker	Transport
Chain 13a	Wind electricity	Central Electrolysis	N/A	Pipeline	Transport
Chain 16a	Grid electricity	Central Electrolysis	N/A	Tanker	Transport
Chain 17a	Wind electricity	Forecourt Electrolysis	N/A	Direct Use	Transport
Chain 22 a	Natural Gas	FC CHP with reformation	No	Direct Use	Stationary

3 Next Stages of the Project

3.1 Scenario Development

In the next stage of the project these nine preferred chains will be used to build up a range of hydrogen economy scenarios and the relative importance of each chain within those scenarios identified. The knowledge gaps associated with the most important chains may then be identified along with the role of research investment in filling those gaps.

Scenarios are images of alternative futures. They are neither predictions nor forecasts. Each scenario can be interpreted as one particular image of how the future could unfold. Scenarios are useful tools for investigating alternative future developments and their implications, for learning about the behaviour of complex systems and for policy making.

Scenarios are not value free and can often be divided into two broad groups: descriptive and normative. Descriptive scenarios are evolutionary and open-ended, and explore paths into the future without any preconceived endpoint. Normative scenarios are explicitly values-based and teleological and explore the routes to desired or undesired endpoints. For the purposes of this programme it is most useful to develop normative scenarios.

3.2 Scenarios to be Modelled

The scenarios to be modelled will be identified by giving due consideration to the requirements of a range of recent documents.

The **New Zealand Energy Strategy** espouses a Government vision for a sustainable energy system based on:

- Resilient low carbon transport
- Security of electricity supply
- Low emissions power and heat
- More efficient energy use
- Sustainable energy technologies and innovation
- Affordability and wellbeing

Targets that need to be reached in order to realise the vision are identified as:

- Generation of 90% electricity from renewables by 2025
- Halving transport emissions per capita by 2040
- Being one of the first countries to have wide spread electric vehicles deployment.

The Framework for a New Zealand Emissions Trading Scheme calls for:

- 90% renewable electricity by 2025
- 50% emission reduction per capita in transport by 2040
- 250,000 hectares new forest by 2020
- Carbon neutrality in public sector by 2025
- Lead the world in widespread deployment of electric vehicles
- Leading the world in agricultural R and D and GHG emission reduction.

NEECS calls for:

- At least 20% improvement in economy wide energy efficiency by 2012
- A further 30 PJ of consumer energy by 2012.

New Zealand Transport Strategy calls for:

an affordable, integrated, safe, responsive, and sustainable transport system by 2010. The vision is underpinned by four principles:

- Sustainability
- Integration
- Safety
- Responsiveness

SDPOA 2003 calls for:

- Building new generating capacity to meet the growth in electricity demand
- Improving our ability to deal with the risk of dry years, especially given the
- Expected depletion of the Maui gas field
- Improving the way we manage energy demand and energy efficiency.

The requirements of related documents such as New Zealand's Climate Change Solutions and Sustainable Energy 2004 appear to be covered by the documents considered above.

The New Zealand Business Council for Sustainable Development has identified four future scenarios. These are:

Shielded – in which energy supply security is the primary driver to the detriment of growth. It is characterized by:

- Low economic growth
- Electricity Crises
- Fuel Shortages

Conservation **-** in which lower growth is accepted as a means to achieve a sustainable outcome. It is characterized by:

- High Energy prices
- High carbon process
- Low economic growth
- Acceptance of supply constraints
- Strong environmental protection policies

Growth – in which the link between energy demand and economic growth is maintained. It is characterized by:

- High economic growth
- High energy demand
- Declining oil supply
- Benign environmental pricing

Transformation – in which the relationship between energy demand and growth is significantly decoupled. It is characterized by:

- Growth though less energy intensive industry
- Strict energy efficiency standards
- Diversity in energy supply – largely renewable

It is likely that the scenarios will range around 50% of the transport fleet being hydrogen powered by 2050 and up to 20% of the domestic and commercial energy being provided by stationary CHP fuel cells.

3.3 Sensitivity Analysis

The scenarios will be subjected to sensitivity analyses relating to, but not necessarily limited to:

- Estimates of the resource size for each feedstock
- Predictions of feedstock price

- Requirements for zero emissions for the transport fleet at point of use.
- Requirements for only renewable resources or fossil fuel sources with carbon capture and storage by 2050.
- Rate of hydrogen technology development.

3.4 Knowledge Gaps and Research Areas – An Initial Assessment.

A Knowledge Gap can be defined as a lack of understanding and insight into the technological processes required to significantly advance the capabilities and growth potential of New Zealand.

It is already possible to begin to identify some of them in relation to the development of a hydrogen economy. Table 3 lists areas where there are knowledge gaps, the international research occurring in these areas and the New Zealand specific issues relative to these areas. This list will be amended and developed in light of the outcomes from the scenario modelling stage of the programme.

The table is ordered under areas of hydrogen production, storage and transport, and use, followed by general issues for hydrogen uptake and finally, impacts on the existing energy systems that may need to be researched.

Table 3 - Initial Assessment of Knowledge Gaps and Areas for Research

Area	Overseas Research	Specific New Zealand Issues
Gasification of coal/biomass	Large research effort into development of advanced gasification technologies.	Application to particular NZ coals (lignite) and biomass requires special attention.
Syngas separation and clean-up	Large research effort required into hot gas R&D including improved catalysts for water gas shift, improved techniques for hydrogen separation and syngas cleaning.	Same as overseas.
Carbon capture	Large research effort into improved pre-combustion carbon capture technologies.	As for gasification of NZ hydrocarbon resources (coal/biomass) – niche needs.
Carbon storage	Improved geochemical modelling capability. CO_2 sequestration demonstrations. Long-term storage liability.	Local geology and CCS site selection in terms of capacity, energy costs and economics. CO_2 pipeline over potentially large distances of NZ terrain. RMA and long term liability.
Pipeline transmission and distribution of gaseous of hydrogen	Several substantial hydrogen pipelines exist. Considerable research into pipeline options as well as some operating pipeline infrastructure.	North to south and south to north pipeline transmission. RMA. Local geography.
Tanker distribution of liquid hydrogen.	Well established for specific uses.	NZ standards required for bulk transportation.
Better storage and distribution methods	Large research effort into chemical and physical storage in solid materials.	Same as overseas.
Refuelling station	The onboard storage medium still to be determined – may yet be metal	Siting of stations in New Zealand. RMA.

Area	Overseas Research	Specific New Zealand Issues
	hydrides, liquid or compressed gas. Whilst systems available there is still room for advance for public refuelling.	
FCV technology	Onboard storage energy density. Fuel cell cost reductions.	System studies - comparison of FCVs vs BEVs and PHEVs in the NZ environment. Pilots and demonstrations.
FC CHP	Improved FC and fuel processor durability. Reduced overall system cost through improved componentry.	Materials and components for global applications. System studies - interaction of CHP FCs with central supply. Market barriers. Pilots and demonstrations.
Standards, safety and codes	Required for transport, storage, application, handling. A major activity within the International Partnership for the Hydrogen Economy.	Adaptation of international standards for NZ, including aid in their development at the international level to minimise adaptation required.
Education and training	Efforts starting to educate policy makers and general public of hydrogen technologies.	Public debate needs to be initiated to better understand the hydrogen energy option and the long term nature of implementation
Electricity Generation	Hydrogen gas turbine development. Molten carbonate fuel cell development.	Same as overseas.
Electricity Transmission Grid	Supergrids – transcontinental transmission of vast amounts of energy via hydricity grids.	Implications of integrating increasing amounts of intermittent renewables. Load management/deferment and storage options for balancing supply and demand. Grid strengthening for transporting increasing amounts of electricity. Impact of hydrogen as a parallel energy vector. FC CHP systems.
Electricity Distribution Networks	National impact of distributed CHP fuel cell systems and forecourt electrolysis on electricity demand and network infrastructure – eg European Smart Grids and US ???	Demand and technical implications relative to NZ's specific network infrastructure. Impact of FC CHP systems.
Gas Supply		Natural gas and oil exploration. LNG. Biomass importation.
Gas Transmission and Distribution Networks	Potential greater use of gas networks for consumer stationary and vehicular FCs in competition to electricity networks	Investigate use of specific existing NZ infrastructure investment for NG-H2 mixing or eventual 100% hydrogen.
Biomass resource choices	Country specific research to establish best species in relation to hydrogen production for land and climate	Evaluate options for biomass energy resource in competition with food growing capacity.

Area	Overseas Research	Specific New Zealand Issues
	options	Evaluate the most appropriate energy use of the constrained biomass resource – e.g. conversion to liquid or gaseous fuel

4 References

[1] FRST Contract CRLE601, "Transitioning to a Hydrogen Economy"

[2] L-B Systemtechnik (2005), Co-ordinator HyWays, HyWays: a European roadmap, Assumptions, visions and robust conclusions from project Phase I, HyWays Consortium, Ottobrun, www.hyways.de

[3] Joint Research Centre of the European Commission (2004) CONCAWE, EUCAR, "Well-to Wheels Analysis of Future Automotive Fuels and Powertrains in the European Setting."

[4] R S Whitney and H Trolove, "Energy Research Investment Strategy", Energy Federation of New Zealand, September 2006

Appendix A Stakeholder Feedback on the Hydrogen Issues Document

A.1 Introduction

We would like to thank all our stakeholders for their thoughtful and insightful input into the selected chains:

BMW, BP, EECA, Electricity Commission, Genesis Energy, HERA, MED, Meridian Energy, MoT, Solid Energy and Transpower.

The Feedback Section is in a questions / response style. Where no response was deemed necessary none has been made. The feedback is grouped under main headings of general, resources, conversion processes, distribution methods and end uses. The author of any particular comment has not been stated and minor editing of the comment undertaken to preserve anonymity without altering the meaning of the feedback. Where it was felt that some clarification of the feedback was necessary this has been included inside square brackets.

There were two main areas that received repeated comment and it seems expeditious to deal with these in this introduction and then refer back to these general comments at relevant points in this following stakeholder feedback:

- There appeared to be some confusion regarding the definition of centralised and decentralised hydrogen production plant, and in particular the use of wind power with electrolysis. We were not suggesting that refuelling take place at a wind farm and our view was that any wind farm would be grid connected to enable transport of the electricity generated there to a central facility close to the demand. This would also allow electrolysis hydrogen production plant to hedge or forward contract wind farm energy on a "surplus pricing basis" and agree to take any surplus at a fixed price if the wind generator so wished to sell "off market". This would provide a potential market for a glut of wind energy at times of low demand and encourage more stability in market prices. We are not familiar enough with the workings of the current wholesale electricity market to know if this is currently possible or whether modification would be required.
- Stakeholders ventured opinions on the relative costs, emissions and primary energy use of several chains in the list presented to them. Whilst we accept that the comments made may indeed turn out to be valid, we believe that this should be done using the rigorous modelling procedures to be used in the next phase of this project. Further justification for this approach comes from the fact that comments for the removal of particular resources, technologies or chains were held by only a small number of the stakeholders. Had a majority of stakeholders taken issue with any particular resource, technology or chain we would have considered this sufficient reason to exclude that chain.

Table A1 lists the chains sent to stakeholders for consideration.

Table A1 - Basic Chain Description as Presented to stakeholders

Chain Codes*	Feedstock	Conversion Process	Distribution	End Use
1a - d	Natural gas	Central reformation	Pipeline	a) FC vehicle b) H_2 ICE vehicle c) Small-scale FC CHP d) Distributed power FC
2 a - d	Natural gas	Central reformation	Tanker	a) FC vehicle b) H_2 ICE vehicle c) Micro-scale FC CHP d) Distributed power FC
3 a - d	Natural gas	Central reformation + CCS	Pipeline	a) FC vehicle b) H_2 ICE vehicle c) Micro-scale FC CHP d) Distributed power FC
4 a - d	Natural gas	Central reformation + CCS	Tanker	a) FC vehicle b) H_2 ICE vehicle c) Micro-scale FC CHP d) Distributed power FC
5 a - d	Coal	Central gasification	Pipeline	a) FC vehicle b) H_2 ICE vehicle c) Micro-scale FC CHP d) Distributed power FC
6 a - d	Coal	Central gasification	Tanker	a) FC vehicle b) H_2 ICE vehicle c) Micro-scale FC CHP d) Distributed power FC
7 a - d	Coal	Central gasification + CCS	Pipeline	a) FC vehicle b) H_2 ICE vehicle c) Micro-scale FC CHP d) Distributed power FC
8 a - d	Coal	Central gasification + CCS	Tanker	a) FC vehicle b) H_2 ICE vehicle c) Micro-scale FC CHP d) Distributed power FC
9 a - d	Biomass	Central gasification	Pipeline	a) FC vehicle b) H_2 ICE vehicle c) Micro-scale FC CHP d) Distributed power FC
10 a - d	Biomass	Central gasification	Tanker	a) FC vehicle b) H_2 ICE vehicle c) Micro-scale FC CHP d) Distributed power FC
11 a - d	Biomass	Central gasification + CCS	Pipeline	a) FC vehicle b) H_2 ICE vehicle c) Micro-scale FC CHP d) Distributed power FC
12 a - d	Biomass	Central gasification + CCS	Tanker	a) FC vehicle b) H_2 ICE vehicle c) Micro-scale FC CHP d) Distributed power FC

Chain Codes*	Feedstock	Conversion Process	Distribution	End Use
13 a - d	Wind generated electricity	Central electrolysis	Pipeline	a) FC vehicle b) H_2 ICE vehicle c) Micro-scale FC CHP d) Distributed power FC
14 a - d	Wind generated electricity	Central electrolysis	Tanker	a) FC vehicle b) H_2 ICE vehicle c) Micro-scale FC CHP d) Distributed power FC
15 a - d	Grid electricity mix	Central electrolysis	Pipeline	a) FC vehicle b) H_2 ICE vehicle c) Micro-scale FC CHP d) Distributed power FC
16 a - d	Grid electricity mix	Central electrolysis	Tanker	a) FC vehicle b) H_2 ICE vehicle c) Micro-scale FC CHP d) Distributed power FC
17 a - b	Wind generated electricity	Refuelling site electrolysis	None	a) FC vehicle b) H_2 ICE vehicle
18 a - b	Grid electricity mix	Refuelling site electrolysis	None	a) FC vehicle b) H_2 ICE vehicle
19 a - b	Natural gas	Refuelling site reformation	None	a) FC vehicle b) H_2 ICE vehicle
20	Coal	Central IGCC + H_2 gas turbine + CCS	Direct use	Electricity for grid
21	Biomass	Central IGCC + H_2 gas turbine	Direct use	Electricity for grid
22 a - b	Natural gas (piped)	FC CHP with reformation	Direct use	a) Micro-scale FC CHP b) Distributed power FC
23 a - b	LPG (by tanker)	FC CHP with reformation	Direct use	a) Micro-scale FC CHP b) Distributed power FC
2 4 a - b	Ethanol (by tanker)	FC CHP with reformation	Direct use	a) Micro-scale FC CHP b) Distributed power FC

a, b, c & d refer to the end use

A.2 General Comments and Information

- Overall all options provided look to be capable.
- We have taken a pass through it [The Hydrogen Issues Document] and no specific comments to make. Looking good.
- As an initial observation, we considered that the Hydrogen Issues document provided a useful stock take of hydrogen technologies and research activities, and the nature of the hydrogen market in NZ.
- Enjoyed reading your report and have become much more aware of issues and pathways – I found it comprehensive and [as I was] lacking specific hydrogen knowledge I certainly feel happy with it and would endorse it. From a research perspective I guess we are happy to sit on the fence at this stage as in general terms we are coming in on the applied end.

- Timeframes would be useful for each chain – say maybe short, medium and long term.

Response*:* We have already considered this – see Figure 6 in the Issues Document. In future we will include timeframes explicitly at relevant points to aid understanding of the chains.

- I did not identify any chains that I thought should be added.
- The 24 supply chains identified all appear relevant to the New Zealand context.

- Drivers quoted on page eleven could be complimented with constraining factors, especially New Zealand geography. Our unique geography is likely to have major impact on feedstock supply and hydrogen distribution systems. The country is comprised of two vertically oriented islands isolated in the pacific. This means that imports or exports are either by tanker, rather than pipeline. Cook Straight offers a (cost) barrier to pipelines, although the barrier is less an issue for the transmission of additional electricity generated from any possible plant in the South Island. This is evidenced through examples of distribution of existing fuels. While CNG is piped extensively over the North Island it is not available in the South Island, where LPG is available as a substitute in bottled form. Petroleum products are transported from Marsden Point to Auckland through a pipeline. However the rest of the country is supplied by coastal tanker to local ports, and then road tankers. For a transition, existing useable infrastructure can also be considered an asset, which is the case for the existing natural gas pipelines electricity grid.

Response: The constraints and factors you mention will be considered in the modelling during the next stage of the programme – see bulleted point in the Introduction.

- I guess my comments are mainly concerned with implications for the electricity system, and alternative technologies that affect the economics of the supply chain. I think you need to look at the competing technologies from the consumers' point of view, and how that will affect scale economies in NZ.

Response: See above

- The report and section 7 appear appropriate to the objectives and span outlined by the scope for the project. I would like to raise a couple of issues; I accept that these may be issues more appropriate to later stages of the project where the consideration of the underlying issues will more readily take place.

Without question a hydrogen economy will have an impact on the electricity transmission business. The nature of the impact will depend on a number of issues not least of which will be the comparative economics of energy transport via hydrogen and electricity. Beyond an unsupported statement of the superior efficiency of gas transmission over electricity transmission the report is innocent of any consideration of the effects of economics and efficiency on energy transport.

This lack does not affect the definition of supply chains but does affect considerations of prioritisation and the nature of viable hydrogen futures and the role of electricity transmission in a hydrogen future. These issues must receive appropriate attention if the project is to be a pragmatic contribution to the energy debate.

Response: This is a valid comment. In the modelling stages such issues will be considered and we are very keen to have input from industry around the relative efficiency assumptions that will be made within the models – see also bulleted comment in the Introduction regarding modelling.

- A comparison with the HyWays Roadmap for Europe shows, that only two pathways could be amended: nuclear and solar thermal high temperature water decomposition.

Response: It was felt that the socio-political situation in New Zealand would rule out nuclear power based technologies. The solar resource in New Zealand is moderately good but probably not sufficient or continuous enough to justify its use for high-temperature water decomposition. The technology is also not sufficiently well developed to allow its future usefulness to be assessed and modelled with any degree of accuracy.

A.3 Resource Based Comments

Favourable technologies for NZ include those that utilise our wealth of coal, wind, natural gas, and renewable electricity. For coal we have large reserves in the south Island. I note that coal can be used as an energy source through IGCC (and CCS) for H2 processes, but the technologies are yet to be become cost effective at current carbon prices. NZ is well placed for wind generation and windfarms are continuing to proliferate. Discovery of new and large natural gas fields remain a possibility in and around NZ, and the existing natural gas distribution system in the North Island is worth consideration. Finally, suitable sites for CCS can be considered a resource, as the international controversy surrounding CCS means that the strictest criteria are likely to be applied to sites. Should NZ be mapped and quality sites be located, they will hold an asset value (especially if located near other complimentary resources like coal).

A.3.1 Oil

§ As an open question we wonder whether including oil reformation as a source of hydrogen could provide a useful benchmark against which to compare other options in the second part of the analysis. Certainly we appreciate there are good reasons why you have already discarded oil as a source of hydrogen energy supply. However, given that over 90% of NZ's [current] hydrogen supply (the demand) comes from the NZ Refining Company, and that oil will remain a major part of the overall energy mix for at least the short term, we believe and oil chain should be included in the next stage of the project. If nothing else, an oil chain provides a yardstick against which to measure the energy, emissions and economics of the various other hydrogen supply options.

Response: Discarding oil was a difficult choice for the reasons outlined in the comment. However one of the main drivers for a hydrogen economy is to move away from oil driven transport systems. We do not want a hydrogen economy dependent on oil. So we made security of supply and cost priorities.

A.3.2 Hydrogen Import Option

§ We also believe that there needs to be a hydrogen import value chain option. In saying this, we appreciate the broad thrust of the report is towards indigenous production and energy security. Nevertheless, the fact remains that NZ is currently a net energy importer. The economic costs and energy losses involved in shipping hydrogen may not make this option viable, but we would like to gain a more detailed appreciation of the assumptions involved to understand some of the technology, energy and economic sensitivities that may actually make this a viable option longer term.

Response: NZ may now be a net energy importer but this is a scenario we want to move away from as we want to be more secure in a world of increasing risk around oil supply. It may well become an internationally traded commodity in the more distant future but for now we have been guided by security of supply and therefore towards indigenous energy sources.

A.3.3 Natural Gas

§ Keep gas chains – There remains some possibility that a large gas fields could be located in or around NZ. Nat gas cleaner at reformation than non CCS coal. CCS will depend on cost and technology.

§ In terms of the chain codes I'd go for: 2 a-d, 4 a-d, 8 a-d. By far the most likely is 17 a-b, 18 a-b, 19 a-b.

- For the introduction phase chains 3b, 3a as well as 4b and 4a seem to be essential, since natural gas could be an economical interesting pathway. Especially the option of CCS (carbon capture & sequestration) could ensure right from the beginning high well-to-wheel CO_2 reductions up to 80%.

A.3.4 Natural Gas as LNG [Liquefied Natural Gas]

§ One possible variation to the natural gas chains is natural gas in the form of LNG, in that it may aid transition in the logistic chain. LNG is the fastest growing international energy trade, low temperature tankers and (-162°C) and shipping is already well understood. LNG trains are directly fed by gas reservoirs and thus provide the potential for CCS. From a New Zealand perspective Great South Basin could eventuate such a play if sufficient gas was to be discovered to warrant an LNG train. Initial transition may be to divert part of this gas stream for production of Hydrogen for a local confined market such as Queenstown initially focusing on static energy requirements. The LPG penetration of this market is a possible example of how that may develop. Starting with small bottle gas supplied via one tank, demands grows to create dedicated site tanks (hotels), followed by reticulation to the intermediary business from a larger storage facility.

Response: We can envisage that this is a way of setting up a demand and that this demand could merit installation of pipelines to carry hydrogen. We think that the LNG possibility is initially sufficiently covered by proposed options for NG as a source since the LNG, wherever it is produced from would most likely be initially introduced into the existing North Island NG pipeline system, and reformed into hydrogen by plants connected to this infrastructure.

§ Again is there a need to look at chain 19 a-b? The issue is the distribution method (i.e. none) hich suggests to me that people are fuelling their FC vehicles and H2 ICE vehicles at the wind farm. Is this likely?

Response: No, there is no refuelling going on at the wind farm. We are simply identifying grid connected wind energy as a specific resource which could be used, as opposed to hydro, which because of its storage component is more manageable within the existing electricity market. Please see comments in the Introduction with regard to this. The same reasoning is true for chain 19 a – b where there is no distribution from the refuelling station but the natural gas is brought by pipeline to the refuelling station site itself.

A.3.5 Coal

§ I question the need to look at the chain 5 a-d, given the issue of cost. In particular noting that the abundance of coal is primarily in the South Island and given that hydrogen/energy demand is in the North Island I question the feasibility of distribution by pipeline. If however we are talking about pipelines to a hydrogen fuelling station for FC vehicles and H2 ICE vehicles then this should be considered. I also question the need to at chain 7 a-d for the same reasons outlined above. Also given the increased cost that CCS will place on the supply chain this exacerbates the cost issue for this particular chain.

Response: We concur that distribution by pipe line from South Island to North Island is at present not an economic option. However, we can envisage that if in the future demand for hydrogen has risen to high levels in the North Island, then someone may well build such a pipeline. The chain we were considering would be based on a North Island mine. Subsequent modelling would then cover the more intimate issues of logistics, topography, geography etc.

§ Delete chains – Although abundant, the process is costly and will rely on low cost CCS to be worthwhile. CCS not guaranteed in South Island where coal deposits are largest. This route relies on both coal to hydrogen technology cost reductions AND CCS technology leaps. Therefore is less likely to occur.

Response: We disagree. It would be dangerous to ignore this option. It is New Zealand's largest natural resource and most secure supply feedstock. Internationally, hydrogen from coal with CCS is an option that is receiving substantial research investment aimed at improved technology and reduced costs. In the longer term there are likely to be significant developments in coal to hydrogen and CCS technologies making these chains more viable.

§ In terms of the chain codes I'd go for: 2 a-d, 4 a-d, <u>8 a-d</u> [This stakeholder only opts for coal with CCS in his preferred chain options but makes no mention at all of coal without CCS].

Response: In the short to medium term central gasification without CCS may be used. We consider that this option needs to be considered, even if to provide a better understanding of the cost of a hydrogen infrastructure with various levels of carbon emissions. Gasification technologies are improving all the time.

A.3.6 Biomass

§ Will the biomass in question be woody biomass?

Response: In the first instance yes. However as technologies develop it is quite possible that other feed stocks will be used, such as straw, other crop residues and animal waste/sewage sludge (e.g. feedstocks for biogas).

- Keep chains – Potential only or development of second generation processes for biomass transformation. Second generation feedstocks will comprise forestry which are located in the North Island. May depend on location of complimentary CCS facility in the North Island.

- Biomass I think would be better converted to liquid fuel since it is easily transported and stored, and CO2 is not a problem.

Response: This may well be right but for the purposes of this exercise we are modelling it for hydrogen production as an alternative to the above. The inefficiencies associated with conversion of biomass to liquid fuels are sufficient cause for assessing this as a potential energy chain.

A.3.7 Wind

- We are keen to understand the economics and energy losses between a stand alone clean energy hydrogen generation plants rather than a centralised grid supported hydrogen production plant. In our experience, the best clean energy resources are not always close to the point of use, and would require considerable investment in hydrogen logistic infrastructure. We also doubt whether such a supply chain would be economic due to the intermittent generation inherent with a wind-only feedstock. This would potentially require investment in hydrogen storage with all its problems and/or investment in some sort of backup hydrogen generation capability. We would therefore consider that grid supported options would be more likely than stand alone wind generated electricity. For these reasons we believe that chain codes 13 a-d, 14 a-d and 17 a-d are unlikely to be viable options when compared with 15 a-d or 16 a-d.

Response: Again some misunderstanding of chain. Please see the Introduction for comment.

- Is there a need to look at the chain 17 a-b? The remote location of most wind farms would in my view suggest that this chain is redundant. The issue is the distribution method (i.e. none) which suggests to me that people are fuelling their FC vehicles and H2 ICE vehicles at the wind farm. Is this likely?

Response: Again some misunderstanding of chain. Please see the Introduction for comment.

- Delete chains – Wind will not offer sufficiently reliable supply for a low cost centralised electrolysis plant. Wind is unlikely to offer sufficiently reliable supply for a low cost refuelling site electrolysis plant. The plant would need to rely on a grid mix.

Response: Wind is an abundant resource and is likely to comprise a large proportion of new renewable energy utilisation in the short and medium term compared to less well developed or already heavily exploited alternative renewable resources. See the Introduction for comment regarding our thinking regarding the wind option. The intention is not necessarily to use wind exclusively for this purpose, but to consider the scenario where hydrogen production is synergistic with relatively high wind penetration in a particular region, and can absorb a substantial portion of the wind supply directly.

- After transition renewable based chains such as wind energy (14 b and a, 17 b and a) are essential, due the issues of limited natural gas resources, even if the peak of world gas production will be several decades after the oil peak which is just 10-15 ahead.

A.3.8 Grid Electricity Mix

- Essential chains – NZ electricity supply currently 65 to 70% renewable. Critical to continue to increase NZ renewable supply to grid and utilise grid for electrolysis either at large or distributed facilities.

A.4 Conversion Process

A.4.1 Centralised versus Decentralised

- From a transport perspective unless the hydrogen can be moved down existing gas pipeline I suspect that refuelling site reformation may be the development path. As with all onsite processes foot print will be a major deciding factor. The original development CNG in NZ is possible example of a development path.

Response: This may be possible during a transition phase but if the ultimate vision of 100% clean transport fuels is to be realised the production volumes are such that it is unlikely to be a dominant long term option.

- 14 a-d. This is a bit unlikely as wind would be grid connected. I don't think there is much economic benefit in 16 a-d since the electrolysis is probably scaleable, and it would be better to distribute and avoid tanker costs. By far most likely is 17 a-b, 18 a-b, 19 a-b [All based at refuelling stations]. All forms of electrical generation contribute to recharging plug-in FCVs and electrolysing H2.

Response: Cannot comment definitively as yet as the actual comparison of costs will come out during the modelling phase – see comment in the Introduction. However if we are starting with the same energy form (bulk electricity) and delivering it as a hydrogen it may be cheaper at some capacity level to convert in bulk to hydrogen and convey the energy by pipeline rather than upgrade the electricity grid and build a lot of small distributed electrolysis plants.Second Generation Production Methods

- What about direct biological, algal and direct solar splitting production methods.

Response: It was felt that at this time these technologies are not sufficiently developed to be considered as a viable near to mid-term option, and insufficient data is available to model any potential chains convincingly.

A.4.2 Biomass/Central IGCC/Hydrogen Gas Turbine

- There was no CCS with this biomass option as opposed to chain 20 using coal as the feedstock where there was – is this correct? And should chains 20 and 21 have SOFCs instead of the hydrogen gas turbines as the end use?

Response: CCS with biomass – this option, while feasible is not considered viable unless a premium is placed on carbon extraction from the atmosphere. It is unlikely that the added cost would be recovered based on a single carbon cost regime so we have assumed no CCS. The question is then whether this is a hydrogen supply chain? Since this option (with CCS) is at present included for coal, we have included this chain for comparison.

SOFCs – This is an embryonic fuel cell technology for which great store is held. However, it is still very experimental and only demonstrated at small scales. We feel that for large scale production it is simpler and more reliable to base the chain on hydrogen turbines which represent a modest upgrade of existing gas turbine technology and are expected to have similar overall plant efficiency.

It could be argued that this set of chains which produce electricity from hydrocarbon fuels are not a true component of the hydrogen economy because there may not be any trading or transmission of hydrogen via an infrastructure. On the other hand, there equally well could be, as the hydrogen production and electricity generation plants may be at different locations. Either way, if carbon dioxide is eventually removed from fossil hydrocarbon fuel and stored in some form, the hydrogen economy in this context is inevitable.

- After transition renewable based chains with biomass (10 b and a) are essential, due the issues of limited natural gas resources, even if the peak of world gas production will be several decades after the oil peak which is just 10-15 ahead.
-

A.4.3 Biomass with CCS

§ Is gasification of biomass with CCS really conceivable?

Response: Gasification of biomass is an up and coming technology. We see no reason why at a future stage CCS could not be incorporated. If it is economically viable without CCS, this will show in the modelling stage, additional CCS costs could be investigated when appropriate.

A.4.4 Reformation at Refuelling Station

§ Delete – Insufficient scale for reformation at refuelling sites.

Response: Small scale reformers (such as the 50kg hydrogen per hour model from Haldor Topsoe) are available and being used.

A.4.5 IGCC Options

§ Delete – IGCC controversial and heavily subsidized overseas to make it worthwhile. CCS locations not mapped yet and CO2 is estimated at US$30 before it is economic. Suggest supercritical coal transformations processes may do the job. Biomass feedstock may not be located conveniently for CCS locations.

Response: IGCC technologies are developing and becoming more economical, not only in terms of cost but also land usage, by-products and versatility. The current entrained gasifiers may not be well suited to NZ coals but there is research being carried out on the less fully developed fluidised bed gasifiers which would be compatible with the NZ feedstock.

Modelling will determine logistics of CCS distances see comment on modelling in the Introduction.

- Finally central pathways offer economies of scale over onsite production in the case of gasification processes (natural gas, biomass). In addition, CCS works only central. In the case of wind energy, a central production offers the possibility for a liquid distribution system.

•

A.4.6 FC CHP with Reformation

§ Keep N gas option – Has benefit of existing natural gas infrastructure already established in the North Island.

§ Delete LPG option – Does not have the benefit of a low cost infrastructure as per natural gas.

Response: Yes, but in the South Island LPG is used instead of natural gas and competes successfully with the alternatives available there. New Zealand has an indigenous supply of LPG. We also expect that if gas is ever extracted from the Great South Basin, a substantial LPG stream would be available as a result of natural gas production.

§ Delete Ethanol option – Ethanol more likely to be used directly in vehicular ICEs.

Response: We disagree. An option now being investigated in a number of countries (not just Brazil) is the use of ethanol for CHP. It may make far more economic sense to use it in this manner since 85% or more of the energy can be utilised, compared with 20% or less in a typical internal combustion engine powered vehicle. At these CHP efficiencies (already demonstrated) the only economic issue is the capital cost and durability of the fuel cell based technology.

A.4.7 Electrolysis

§ 14 a-d. This is a bit unlikely as wind would be grid connected. I don't think there is much economic benefit in 16 a-d since the electrolysis is probably scaleable, and it would be better to distribute and avoid tanker costs.

Response: We believe the various options will be ordered depending on process scale, distance to market and timeframe. In our case wind would be grid connected and hydrogen produced at a suitably sized electrolysis plant near the demand centre, not near the wind farm – see Introduction for more discussion around the wind/electrolysis options.

A.5 Distribution Methods

A.5.1 Tanker

§ In terms of narrowing the chains further (i.e. determining what are essential) I would look to rule out the coal and natural gas "tanker" ones (i.e. 2 a-d, 4 a-d, 6 a-d and 8 a-d). In particular, given that natural gas and coal are found in basins this is likely to mean (if additional gas is found in meaningful quantities) that these can be "centralised" and distributed via pipelines as opposed to tanker.

Response: In the long term it is probably correct that pipeline distribution will be used as demand increases, however, in the short term tankers are likely to play a role. The relative costs, emissions and energy use of the tanker options compared to the pipeline options will be examined in the next stage of the project during the chain modelling – see comment regarding modelling in the Introduction.

A.5.2 Pipeline

- I would rule out the pipeline option for wind (13 a-d) as wind will be largely distributed and therefore any hydrogen pipeline network would need to be extensive.

Response: See comments on wind/electrolysis in the Introduction.

A.6 End uses

- [Chain] 20 is also a possibility for base load or mid order generation. I doubt there would be much stationary H_2 consumption in New Zealand, we are really looking at transport [i.e. no to chains 21 to 24 as they are not for transport either].

Response: We believe (based on strong international opinion) that stationary use of hydrogen will help in the transition phase by boosting demand for both hydrogen and fuel cells through to possibly 2015-2020 before transport demand starts to dominate and drive a hydrogen infrastructure economy .

A.6.1 Hydrogen/electric hybrid trains

- From a transport perspective I do wonder if a Hydrogen train may be one of the initial steps. Effectively electrical trains that run partly on overhead power and also hydrogen powered electrical generators for longer haul. The advantage being that it is on a captured route with reasonable volume in a public transport option and may have the potential to be a first mover.

Response: An interesting concept and possibly a great demonstration project relevant to New Zealand in contrast with many overseas countries because much of our main route rail system is not electrified. It might also be useful in setting up demand early in the development of hydrogen infrastructure. However, when compared to the national car fleet it would have a relatively small impact long term.

A.6.2 Micro FC CHP & Distributed Power FC

- It is our view that the economics and energy conversion losses are unlikely to make small scale CHP and distributed power cells a realistic option worthy of further study when compared with grid electricity or natural gas as a feedstock. As the Hydrogen Issues document notes, gas CHP technologies have very high efficiencies, which raises the question of why convert gas to hydrogen, and likely to mean that value chains 22 a-b and 23 a-b are likely to drop out in any detailed economic analysis. While there are lower efficiencies in simple generation using gas, or the transmission of grid electricity to distributed power fuel cells, we wonder whether they are more than the energy losses incurred by hydrogen conversion, compression, transmission and storage. It would also be interesting to understand whether this has any implications for your working hypothesis of the initial development of a hydrogen economy via smaller scale distributed or stationary applications.

Response: This is a commonly held view in New Zealand, and under Business as Usual scenario (BAU) economics is probably realistic. However we consider for a number of reasons that in the medium term these technologies (like CCS and a host of hydrogen technologies not yet proven for large scale energy production) could evolve to contribute substantially to the stationary energy mix, and ultimately even form a component of a hydrogen transport infrastructure by delivering home production of hydrogen. This project is required to evaluate scenarios for transformational and competitive technologies, not just a BAU future.

There may also be some misunderstanding of the nature of this set of chains. Before the development of a transport hydrogen infrastructure, hydrogen fuel for a fuel cell based CHP system must be produced on site. This is achieved by an integrated micro-reformer to produce hydrogen from delivered fuels. This system runs off natural gas, LPG, kerosene etc. Carbon dioxide is not sequestered, but overall emissions are reduced (potentially to half) by the high CHP efficiency. Subsequently, when a large scale hydrogen infrastructure is built up to fuel the vehicle fleet, there is no reason why this hydrogen will not be cost effective as a distributed fuel (either by pipe or tanker for stationary fuel cells) to be used in these fuel cells by bypassing the onboard reformer. In fact it cannot help but be cost effective because of the fuel cell based efficiencies possible. This is no different to the current growth market for reticulated LPG in Christchurch where it is cost effective to pipe it to businesses in competition with electricity, which was somewhat hard to imagine twenty years ago. However it is simply based on one premise – mass production of cost-effective and durable fuel cells.

A.6.3 Battery Electric Vehicles (BEV) versus Hydrogen Fuelled Vehicles.

§ In Table 1 you have laptop batteries at US$11000/kW, and then mention that the USDoE target for fuel cells as $30/kW in 2015. The USDoE target for batteries is US$20/kW by 2010, with total cost for FCV battery as $500 (40kW), and also a target of $75/kWh for EV batteries. These targets seem equally as plausible as the fuel cell targets.

My point is that from the point of view of a car purchaser, it could very well turn out to be a better deal to get a FCV with plug-in capability than a 'pure' hydrogen FCV. Suppose you want 100kW performance. Existing Li batteries have 5min recharge capability (Altair and A123) (or 1min for Toshiba prototype) so 7kWh would deliver 80kW peak performance. 7kWh would give you about 50km range in electric mode. At $75/kWh the cost per kW is actually less than the DoE target. A 20kW FC would suffice for providing energy for long drives, since power demand at 100km/hr is about 12-15kW.
From the point of view of the consumer this vehicle is lower capital cost than a 'pure FCV', and has much lower running cost. Assuming 80% of drives are less than 50km, the bulk of travel will be in electric mode at about $1 to $1.50 per 100km for off peak charging and say $2 - $2.50 per 100km for on peak charging. This is much cheaper than hydrogen. I imagine this would be more like $5 - $10/ 100km. So the consumer will pay more for a plug-in hybrid FCV than a pure FCV.
Of course it all depends on the relative cost of fuel cells, batteries, grid electricity, and hydrogen. But I think you have to admit it is a reasonable scenario.

Response: You bring up some very good points. There has been a lot of press recently about the resurgence of BEVs and “plug in” hybrids, mostly based on the significant progress in rechargeable Li Ion batteries. We think they need to be taken seriously. However our current view is that any progress in vehicle battery technology will benefit the uptake of fuel cells rather than hinder it. A combined FC-BEV can be visualised as the ultimate hybrid. Short range operation on battery electricity and longer range operation on (higher cost/km) hydrogen fuel. Our reason for this view is simple. The practicalities of say 1 minute recharge of a BEV capable of 500km range have not been considered in the popular press. Even if say only 100kWh is required, to deliver this in 1 min requires energy transfer at a rate of 6MW. A refuelling station with 10 charger stands will require 60MW plus losses which at this rate could mean a peak electrical capacity of 70MW is required for the refuelling station. This is somewhat mind boggling, but does illustrate the simple facts around recharging electrical storage systems which people seem to continually forget. Also the electrical current required to recharge a battery at this rate, even at a high 600V bus is 10,000A - clearly impractical. So batteries will never be used in standard sized vehicles for rapid refuelling on long distance travel. Transfer of the energy via a chemical fuel is the only practical option. Hydrogen is seen at present as the best long-term option, based on the eventual development of acceptable fuel cell technology. This is the reason for the hydrogen FCV transport energy chains. However the impact of BEV options could be in the volume of hydrogen required, as you have indicated below. The question is around the likely ratio. We have proposed one extreme (100% hydrogen FCV) and the impacts of varying reductions on this level can be extrapolated from the modelling.

> So if this is the case, maybe 80% of the energy for domestic and light commercial vehicles would be grid electricity, and only 20% would be hydrogen. Also, I expect some of the hybrid vehicles would be diesel or bio diesel series hybrids, so even less than 20% of the travel would be hydrogen fuelled, but again that depends on relative economics.
>
> Under this 'plug-in' scenario the demand for hydrogen in the hydrogen in the hydrogen economy is much reduced. I don't know by how much, but it must affect the economics of the delivery mechanisms. It could lead to a preference for refuelling site electrolysis.
> So in this scenario I'd say all the supply chains involving pipeline distribution are eliminated. I think this would also lead to a preference for 'electricity' as the feedstock, since there may not be adequate demand to justify the scale economies of central production.

Response: The purpose of this process is to consider a range of likely scenarios, and if battery and system power performance as described above cannot be achieved, this scenario will not eventuate.

> In terms of future research I think you'd need to look at a scenario in which the ABC, Freedom Car, DOE goals are met for batteries, fuel cells, and hydrogen storage and then use that information to construct the best value for money vehicle from a consumers perspective. I think you'd cost electricity at something like what we see today, and assume hydrogen is formed by electrolysis at the refuelling site, or centrally produced by the lowest cost means in NZ to give a bound on the relative benefits of electric mode driving vs fuel cell.

Response: Agreed, this is a fair starting point, also converting the metrics to NZ conditions, but a key issue may be what a consumer would be prepared to pay for fast refuelling on long trips, or even convenient fuelling on short trips. For the plug-in hybrid FCV concept, the relative production costs of the various technology components needed for each mode and their relative durability as well as the differential fuel costs and convenience factors will ultimately decide the configuration. This is too complex a mix to predict at the present stage of development.

> This scenario also has quite significant implications for the electricity system. The presence of H2 electrolysers and plugged-in vehicles should mean that by employing smart grid concepts, we can connect far more intermittent renewable generation. There may also be implications for transmission and distribution infrastructure e.g. it may be feasible to roll-out charging stations in CBD parking spaces.

Response: Later stages of the programme involve modelling the various scenarios. Until this is completed we cannot say if they will be cost competitive.

> Centralised reformation and carbon capture may not compete with renewable generation and electrolysis, since the carbon sequestration cost is high. The electrolysis pathway enables generators to compete in two different markets, to some extent.

Response: Again we need to carry out a full analysis to be able to ascertain this as mentioned in the Introduction to the Issues Document.

§ It looks like transport will have to wait a while. Costs of technologies to be replaced by hydrogen systems are listed on page 12. It is notable that Internal Combustion Engine (ICE) technology is the least cost at US$30 per kilowatt; significantly lower than the four other non-transport relates routes. Although highly sought after, it is acknowledged that the transport sector is likely to be a later adopter of hydrogen systems. There is significant attention drawn to electric vehicles at present, and their value in the NZ system is that they may draw upon a grid which is supplied from 65-70% renewable energy. This competing technology may develop at least as quickly as hydrogen and could vie as the dominant energy system. Synergy may develop where possibly cheaper hydrogen systems could provide fuel for fuel cell vehicles.

Response: As referred to elsewhere, in the context of current knowledge on the various technology options these are valid points. However the project is required to address likely "hydrogen intensive" scenarios. Our view is that at present there is insufficient evidence to be sure of the outcomes for any of these technologies. We would very much like to see a similar exercise to this undertaken around plug-in BEVs and hybrids.

However we must start now in planning this future and adapt as we go, if we are to have any chance of delivering the solution(s). As identified above, we do not see any evidence, either at the theoretical level (i.e. physics, chemistry and engineering) or from technology demonstrations that battery technology will deliver the combined range and refuelling rate capability taken for granted in existing vehicles. Potentially hydrogen fuel can, if at present with some disadvantage in tank volume/mass. We think this is sufficient justification to evaluate its potential role in these supply chains.

Appendix B Description of the chains modelled for E3

Chain 1

Natural gas from gas field in Taranaki

350km natural gas pipeline to just south of Auckland

Central SMR plant just south of Auckland very close to natural gas main (using electricity from the grid)

20km large diameter hydrogen pipeline through central Auckland carrying the whole output of the reformation plant

5km small diameter hydrogen pipeline to connect end point to the main hydrogen pipeline

End point:

a) Refuelling station with compressors (electricity supply from the grid) into a fuel Cell vehicle with compressed gas storage

b) Refuelling station into an ICE

c) Small scale FC CHP

d) Distributed power FC

Chain 2

Natural gas from gas field in Taranaki

350km natural gas pipeline to just south of Auckland

Central SMR plant just south of Auckland very close to natural gas main (using electricity from the grid)

Compress hydrogen for tanker transport (using electricity from grid)

Tanker transport 25km

End point:

a) Refuelling station with compressors into a fuel Cell vehicle with compressed gas storage
b) Refuelling station into an ICE
c) Small scale FC CHP
d) Distributed power FC

Chain 3

Natural gas from gas field in Taranaki

350km natural gas pipeline to just south of Auckland

Central SMR plant with CCS just south of Auckland very close to natural gas main (using electricity from the grid)

20km large diameter hydrogen pipeline through central Auckland carrying the whole output of the reformation plant

5km small diameter hydrogen pipeline to connect end point to the main hydrogen pipeline

End point:

a) Refuelling station with compressors (electricity supply from the grid) to fuel Cell vehicle with compressed gas storage
b) Refuelling station into an ICE
c) Small scale FC CHP
d) Distributed power FC

Carbon dioxide captured at the reformation plant is piped back 350km to the gas field in Taranaki for sequestration.

Chain 4

Natural gas from gas field in Taranaki

350km natural gas pipeline to just south of Auckland

Central SMR plant with CCS just south of Auckland very close to natural gas main (using electricity from the grid)

Compress hydrogen for tanker transport (using electricity from grid)

Tanker transport 25km

End point:

a) Refuelling station with compressors (electricity supply from the grid) to fuel Cell vehicle with compressed gas storage
b) Refuelling station into an ICE
c) Small scale FC CHP
d) Distributed power FC

Carbon dioxide captured at the reformation plant is piped back 350km to the gas field in Taranaki for sequestration.

Chain 5

Sub-bituminous coal mined in Rotowaro, Waikato near Huntly power station

Truck transport 20km to gasifier at Huntly

Coal gasification plant

100km hydrogen large diameter gas pipeline to Auckland

5km small diameter hydrogen pipeline to connect end point to the main hydrogen pipeline

End point:

a) Refuelling station with compressors (electricity supply from the grid) to fuel Cell vehicle with compressed gas storage

b) Refuelling station into an ICE
c) Small scale FC CHP
d) Distributed power FC

Chain 6

Sub-bituminous coal mined in Rotowaro, Waikato near Huntly power station

Truck transport 20km to gasifier at Huntly

Coal gasification plant

Compress hydrogen for tanker transport (using electricity from grid)

Tanker transport 100km

End point:

a) Refuelling station with compressors (electricity supply from the grid) to fuel Cell vehicle with compressed gas storage
b) Refuelling station into an ICE
c) Small scale FC CHP
d) Distributed power FC

Chain 7

Sub-bituminous coal mined in Rotowaro, Waikato near Huntly power station

Truck transport 20km to gasifier at Huntly

Coal gasification plant with CCS

100km hydrogen large diameter gas pipeline to Auckland

5km small diameter hydrogen pipeline to connect end point to the main hydrogen pipeline

End point:

a) Refuelling station with compressors (electricity supply from the grid) to fuel Cell vehicle with compressed gas storage
b) Refuelling station with ICE
c) Small scale FC CHP
d) Distributed power FC

Carbon dioxide captured at the reformation plant is piped back 350km to the gas field in Taranaki for sequestration.

Chain 8

Sub-bituminous coal mined in Rotowaro, Waikato near Huntly power station

Truck transport 20km to gasifier at Huntly

Coal gasification plant with CCS

Compress hydrogen for tanker transport (using electricity from grid)

Tanker transport 100km

End point:

a) Refuelling station with compressors (electricity supply from the grid) with fuel Cell vehicle with compressed gas storage
b) Refuelling station into an ICE
c) Small scale FC CHP
d) Distributed power FC

Carbon dioxide captured at the reformation plant is piped back 350km to the gas field in Taranaki for sequestration.

Chain 9

Forestry residue from the Central N. Island Plateau

Wood moved by trucks 50km to Tokoroa

Biomass gasification plant at Tokoroa (size to the order of 10-30MW)

200km large diameter hydrogen pipeline through central Auckland carrying the whole output of the reformation plant

5km small diameter hydrogen pipeline to connect end point to the main hydrogen pipeline

End point:

a) Refuelling station with compressors (electricity supply from the grid) to fuel Cell vehicle with compressed gas storage
b) Refuelling station into ICE
c) Small scale FC CHP
d) Distributed power FC

Chain 10

Forestry residue from the Central N. Island Plateau

Wood moved by trucks 50km to Tokoroa

Biomass gasification plant at Tokoroa (size to the order of 10-30MW?)

Compress hydrogen for tanker transport (using electricity from grid)

Tanker transport 200km

End point:

a) Refuelling station with compressors (electricity supply from the grid) to fuel Cell vehicle with compressed gas storage
b) Refuelling station with ICE
c) Small scale FC CHP
d) Distributed power FC

Chain 11

Forestry residue from the Central N. Island Plateau

Wood moved by trucks 50km to Tokoroa

Biomass gasification plant at Tokoroa (size to the order of 10-30MW?) with CCS

200km large diameter hydrogen pipeline through central Auckland carrying the whole output of the reformation plant

5km small diameter hydrogen pipeline to connect end point to the main hydrogen pipeline

End point:

a) Refuelling station with compressors (electricity supply from the grid) to fuel Cell vehicle with compressed gas storage
b) Refuelling station into an ICE
c) Small scale FC CHP
d) Distributed power FC

Carbon dioxide captured at the reformation plant is piped back 200km to the gas field in Taranaki for sequestration.

Chain 12

Forestry residue from the Central N. Island Plateau

Wood moved by trucks 50km to Tokoroa

Biomass gasification plant at Tokoroa (size to the order of 10-30MW) with CCS

Compress hydrogen for tanker transport (using electricity from grid)

Tanker transport 200km

End point:

a) Refuelling station with compressors (electricity supply from the grid) to fuel Cell vehicle with compressed gas storage
b) Refuelling station into an ICE
c) Small scale FC CHP
d) Distributed power FC

Carbon dioxide captured at the reformation plant is piped back 200km to the gas field in Taranaki for sequestration.

Chain 13

Windfarm around Palmerston North region (size to suit electrolyser average demand)

Electrical connection from windfarm to electrolyser via national grid of 500km in length (i.e. new connection from windfarm to existing grid plus strengthening if required of existing grid but treated as whole new connection)

Central electrolysis plant sited next to the national electricity grid just south of Auckland

20km large diameter hydrogen pipeline through central Auckland carrying the whole output of the electrolyser

5km small diameter hydrogen pipeline to connect end point to the main hydrogen pipeline

End point:

a) Refuelling station with compressors (electricity supply from the grid) to fuel Cell vehicle with compressed gas storage

b) Refuelling station into ICE
c) Small scale FC CHP
d) Distributed power FC

Chain 14

Windfarm around Palmerston North region (size to suit electrolyser average demand)

Electrical connection from windfarm to electrolyser via national grid of 500km in length (i.e. new connection from windfarm to existing grid plus strengthening if required of existing grid but treated as whole new connection)

Central electrolysis plant sited next to the national electricity grid just south of Auckland

Compress hydrogen for tanker transport (using electricity from grid)

Tanker transport 25km

End point:

a) Refuelling station with compressors (electricity supply from the grid) to fuel Cell vehicle with compressed gas storage
b) Refuelling station into an ICE
c) Small scale FC CHP
d) Distributed power FC

Chain 15

NZ Grid electricity mix supplied by national grid

Central electrolysis plant sited next to the national electricity grid just south of Auckland

20km large diameter hydrogen pipeline through central Auckland carrying the whole output of the electrolyser

5km small diameter hydrogen pipeline to connect end point to the main hydrogen pipeline

End point:

a) Refuelling station with compressors (electricity supply from the grid) to fuel Cell vehicle with compressed gas storage
b) Refuelling station into an ICE
c) Small scale FC CHP
d) Distributed power FC

Chain 16

NZ Grid electricity mix supplied by national grid

Central electrolysis plant sited next to the national electricity grid just south of Auckland

Compress hydrogen for tanker transport (using electricity from grid)

Tanker transport 25km

End point:

a) Refuelling station with compressors (electricity supply from the grid) to fuel Cell vehicle with compressed gas storage
b) Refuelling station into ICE

c) Small scale FC CHP
d) Distributed power FC

Chain 17

Wind farm around Palmerston North region (size to suit electrolyser average demand)

Electrical connection from wind farm to electrolyser via national grid of 520km in length (i.e. new connection from wind farm to existing grid plus strengthening if required of existing grid but treated as whole new connection)

Small-scale de-centralised electrolysis plant on site

End point:

a) Refuelling station with compressors (electricity supply from the grid) to fuel Cell vehicle with compressed gas storage
b) Refuelling station into an ICE
c) Small scale FC CHP
d) Distributed power FC

Chain 18

NZ Grid electricity mix supplied by national grid

Small-scale de-centralised electrolysis plant on site

End point:

a) Refuelling station with compressors (electricity supply from the grid) to fuel Cell vehicle with compressed gas storage
b) Refuelling station into an ICE
c) Small scale FC CHP
d) Distributed power FC

Chain 19

Natural gas from gas field in Taranaki

370km natural gas pipeline to site in Auckland

Small-scale de-centralised natural gas SMR plant on site

End point:

a) Refuelling station with compressors (electricity supply from the grid) to fuel Cell vehicle with compressed gas storage
b) Refuelling station into an ICE
c) Small scale FC CHP
d) Distributed power FC

Chain 20

Sub-bituminous coal mined in Rotowaro, Waikato near Huntly power station

Truck transport 20km to gasifier at Huntly

IGCC coal gasification and combined cycle hydrogen gas turbine plant with CCS

Electricity transmission (to Auckland)

Electricity distribution (within Auckland)

End point:

Direct central use to generate electricity

Carbon dioxide captured at the reformation plant is piped back 350km to the gas field in Taranaki for sequestration.

Chain 21

Forestry residue from the Central N. Island Plateau

Wood moved by trucks 50km to Tokoroa

IGCC biomass gasification and combined cycle hydrogen gas turbine plant

Electricity transmission (to Auckland)

Electricity distribution (within Auckland)

End point:

Direct central use to generate electricity

Chain 22

Natural gas from gas field in Taranaki

350km natural gas pipeline to Auckland

Natural gas supply network to individual house

End use:

a) Small scale domestic FC CHP with onboard reformer
b) Distributed power PC with onboard reformer

Match domestic heat load – electricity produced will not meet local demand so either excess is sent to the grid or extra requirements obtained from the grid

Chain 23

LPG recovered during natural gas processing in Taranaki

350km tanker transport to domestic delivery in Auckland

End use:

a) Small scale FC CHP with onboard reformer
b) Distributed power FC with onboard reformer

Match domestic heat load – electricity produced will not meet local demand so either excess is sent to the grid or extra requirements obtained from the grid

Chain 24

Forestry residue from the Central N. Island Plateau

Wood moved by trucks 50km to Tokoroa

Ethanol production from wood waste.

200km natural tanker journey to domestic delivery in Auckland

End use:

a) Domestic FC CHP with onboard reformer

Match domestic heat load – electricity produced will not meet local demand so either excess is sent to the grid or extra requirements obtained from the grid

Reference Chains used for modelling in E3

Chain Ref1a

Oil Well in Middle East

Crude oil pipeline to super-tanker docks

Transport to NZ by super-tanker (from Middle East – ship fuel)

Pipeline from docks to refinery at Marsden Point

Refining process (energy use – uses some oil for heat and hydrogen, electricity from grid) to produce Diesel fuel

Use Existing pipeline to Auckland

Tanker transport around Auckland – average 10km

End use:

Refuelling station for Diesel fuels (electricity from grid) to a diesel vehicle

Chain Ref1b

Oil Well in Middle East

Crude oil pipeline to super-tanker docks

Transport to NZ by super-tanker (from Middle East – ship fuel)

Pipeline from docks to refinery at Marsden Point

Refining process (energy use – uses some oil for heat and hydrogen, electricity from grid) to produce Gasoline fuel

Use Existing pipeline to Auckland

Tanker transport around Auckland – average 10km

End use:

Refuelling station for Gasoline fuels (electricity from grid) to gasoline vehicle

Chain Ref1c

Oil Well in Middle East

Crude oil pipeline to super-tanker docks

Transport to NZ by super-tanker (from Middle East – ship fuel)

Pipeline from docks to refinery at Marsden Point

Refining process (energy use – uses some oil for heat and hydrogen, electricity from grid) to produce Diesel fuel

Use Existing pipeline to Auckland

Tanker transport around Auckland – average 10km

End use:

Refuelling station for Diesel fuels (electricity from grid) to a fuel efficient Diesel vehicle

Chain Ref1d

Oil Well in Middle East

Crude oil pipeline to super-tanker docks

Transport to NZ by super-tanker (from Middle East – ship fuel)

Pipeline from docks to refinery at Marsden Point

Refining process (energy use – uses some oil for heat and hydrogen, electricity from grid) to produce Diesel fuel

Use Existing pipeline to Auckland

Tanker transport around Auckland – average 10km

End use:

Refuelling station for Diesel fuels (electricity from grid) to a hybrid Diesel vehicle

Chain Ref2a

NZ electricity generation mix

Transmission losses

Distribution losses

End use:

Electricity delivered to end user

Chain Ref3a

NZ electricity generation mix

Transmission losses

Distribution losses

End use:

Electricity delivered to end user and converted to space and water heating with high efficiency (NB domestic space and water heating dominated by electricity as the source

Appendix C Detail of Chains Modelled leading to end use point

Table C1 - Chain data and scales

		H2 prod scale	CCS	H2 transport distance	H2 transport method
		MW		km	
1	NG field/Central SMR / CGH2 Pipeline /end use	3.9	no	25	pipe
2	NG field/Central SMR / CGH2 Truck /end use	3.9	no	25	truck
3	NG field/Central SMR + CCS / CGH2 Pipeline /end use	844	yes	25	pipe
4	NG field/Central SMR + CCS / CGH2 Truck / end use	844	yes	25	truck
5	Coalfield / Central CG NI / CGH2 Pipeline /end use	845	no	100	pipe
6	Coalfield / Central CG NI / CGH2 Truck /end use	845	no	100	truck
7	Coalfield / Central CG + CCS NI / CGH2 Pipeline /end use	845	yes	100	pipe
8	Coalfield / Central CG + CCS NI / CGH2 Truck /end use	845	yes	100	truck
9	Biomass Residue / Chips Truck / Cental Gasification / CGH2 Pipeline /end use	5.2	no	200	pipe
10	Biomass Residue / Chips Truck / Cental Gasification / CGH2 Tanker /end use	5.2	no	200	truck
11	Biomass Residue Gasification + CCS / Central NI / CGH2 Pipe /end use	5.2	yes	200	pipe
12	Biomass Residue Gasification + CCS / Central NI / CGH2 Truck /end use	5.2	yes	200	truck
13	Wind Electricity / Powerlines / Central Electrolysis / CGH2 Pipeline /end use	2.3	n/a	25	pipe
14	Wind Electricity / Powerlines / Central Electrolysis / CGH2 Truck /end use	2.3	n/a	25	truck
15	Grid Electricity / Central Electrolysis / CGH2 Pipeline /end use	2.3	n/a	25	pipe

16	Grid Electricity / Powerlines / Central Electrolysis / CGH2 Truck /end use	2.3	n/a	25	truck
17	Wind Electricity / Powerlines / SS Electrolysis /end use	0.18	n/a	0	none
18	Grid Electricity / Onsite Electrolysis /end use	0.18	n/a	0	none
19	Natural Gas / Onsite SMR /end use	0.96	no	0	none
20	Coalfield / Central CG + CCS / Combined Cycle / Electricity production	845	yes	0	none
21	Biomass Residue / Central BG / Combined Cycle / Electricity production	5.2	no	0	none
22	NG Pipeline / Micro CHP		n/a	n/a	none
23	LPG / Micro CHP		n/a	n/a	none
24	Wood / Bio Ethanol / Micro CHP	138	n/a	n/a	none
ref1a	Oil field/Crude Oil / Diesel / Current Vehicle				
ref1b	Oil field/Crude Oil / Gasoline / Current Vehicle				
ref1c	Oil field/Crude Oil / Diesel / Fuel Efficient Vehicle				
ref1d	Oil field/Crude Oil / Diesel / Hybrid Vehicle				
ref2a	NZ Electricity Mix / HV / MV Transmission / E end use				
ref3a	NZ Electricity Mix / HV / MV Transmission / Heat end use				

For example:
Chain 1 reads…Natural gas /central steam methane reformation / compressed gas hydrogen pipeline / end use (transport or stationary) station
Chain ref 2a reads…….electricity from NZ grid / high voltage / medium voltage Transmission / Electricity end use

Appendix D Results of E3 Modelling

Table D1 - Energy, Emissions and Cost for Transport Chains

		FC Vehicle per km (a chains)			ICE Vehicle per km (b chains and ICE reference chains)		
		Energy use per km	CO2 eq emissions per km	NZ$ per km	Energy use per km	CO2 eq emissions per km	NZ$ per km
1	SMR via pipeline	0.42	85.91	0.030	0.76	154.64	0.054
2	SMR via truck	0.43	87.39	0.035	0.77	157.30	0.063
3	SMR with CCS via pipeline	0.40	18.10	0.024	0.72	32.58	0.043
4	SMR with CCS via truck	0.40	19.72	0.029	0.72	35.50	0.052
5	Coal gasifier via pipeline	0.58	191.52	0.021	1.04	344.74	0.038
6	Coal gasifier via truck	0.59	196.47	0.039	1.06	353.65	0.070
7	Coal gasifier with CCS via pipeline	0.67	14.74	0.025	1.21	26.53	0.045
8	Coal gasifier with CCS via truck	0.68	21.24	0.043	1.22	38.23	0.077
9	Biomass gasifier via pipeline	0.59	12.59	0.029	1.06	22.66	0.052
10	Biomass gasifier via truck	0.61	25.62	0.064	1.10	46.12	0.115
11	Biomass gasifier with CCS via pipeline	0.67	-177.02	0.033	1.12	-318.64	0.059
12	Biomass gasifier with CCS via truck	0.69	-160.75	0.068	1.24	-289.35	0.122
13	Central Wind Electrolysis via pipeline	0.45	3.64	0.062	0.81	6.55	0.112
14	Central Wind Electrolysis via truck	0.45	5.29	0.066	0.81	9.52	0.119
15	Central Grid Electrolysis via pipeline	0.61	90.71	0.062	1.10	163.28	0.112
16	Central Grid Electrolysis via truck	0.61	92.18	0.066	1.10	165.92	0.119
17	Wind Onsite Electrolysis	0.49	0.00	0.083	.088	0.00	0.149
18	Grid Onsite Electrolysis	0.67	100.09	0.083	1.21	180.16	0.149
19	Natural Gas Onsite SMR	0.42	85.41	0.040	0.76	153.74	0.072
20	Coal combined cycle electricity						
21	Biomass combined cycle electricity						
22/23	Natural gas/LPG distributed FC						
24	Wood to bioethanol distributed FC						
ref1a	Crude oil diesel				0.59	170.03	0.039
ref1b	Crude oil petrol				0.71	197.12	0.049
ref1c	Crude oil diesel				0.55	154.44	0.036
ref1d	Crude oil diesel				0.45	126.89	0.030
ref2a	NZ electricity grid to electricity						
ref3a	NZ electricity grid to heat						

Table D2 - Energy, Emissions and Cost for Stationary Chains

		Distributed CHP per kWh (c chains) *			Distributed Power FC[1] (no heat) per kWh (d chains)*		
		Energy use per kWh	CO2 eq emissions per kWh	NZ$ per kWh	Energy use per kWh	CO2 eq emissions per kWh	NZ$ per kWh
1	SMR via pipeline	1.78	367.67	0.154	2.98	614.00	0.257
2	SMR via truck	1.79	374.31	0.174	2.99	625.09	0.290
3	SMR with CCS via pipeline	1.66	62.72	0.127	2.77	104.74	0.211
4	SMR with CCS via truck	1.67	69.99	0.147	2.79	116.89	0.245
5	Coal gasifier via pipeline	2.48	842.55	0.113	4.15	1407.06	0.189
6	Coal gasifier via truck	2.52	864.84	0.192	4.20	1444.28	0.321
7	Coal gasifier with CCS via pipeline	2.89	47.62	0.131	4.83	79.52	0.219
8	Coal gasifier with CCS via truck	2.92	76.83	0.210	4.88	128.30	0.350
9	Biomass gasifier via pipeline	2.53	37.93	0.148	4.22	63.35	0.247
10	Biomass gasifier via truck	2.60	96.53	0.305	4.34	161.21	0.509
11	Biomass gasifier with CCS via pipeline	2.92	-812.40	0.168	4.87	-1356.71	0.280
12	Biomass gasifier with CCS via truck	2.98	-739.24	0.324	4.98	-1234.52	0.541
13	Central Wind Electrolysis via pipeline	1.92	0.00	0.298	3.20	0.00	0.498
14	Central Wind Electrolysis via truck	1.93	7.41	0.318	3.22	12.37	0.531
15	Central Grid Electrolysis via pipeline	2.61	391.55	0.298	4.37	653.88	0.498
16	Central Grid Electrolysis via truck	2.62	398.14	0.318	4.38	664.89	0.531
17**	Wind Onsite Electrolysis	2.12	0.00	0.393	3.54	0.00	0.657
18**	Grid Onsite Electrolysis	2.89	432.90	0.393	4.83	722.95	0.657
19**	Natural Gas Onsite SMR	1.78	366.90	0.200	2.97	612.72	0.333
20	Coal combined cycle electricity				4.74	77.99	0.151
21	Biomass combined cycle electricity				4.10	61.60	0.174
22/23	Natural gas/LPG distributed FC	1.22	90.37	0.093	2.71	200.62	0.206
24	Wood to bioethanol distributed FC	3.56	135.14[2]	0.089	7.91	300.00[2]	0.197
ref1a	Crude oil diesel						
ref1b	Crude oil petrol						
ref1c	Crude oil diesel						
ref1d	Crude oil diesel						
ref2a	NZ electricity grid to electricity	1.51	225.92	0.065			
ref3a	NZ electricity grid to heat	1.59	237.8051	0.068			

* Except for Chains 20 and 21 where the transport application is not relevant and the sole end use is for supplying electricity directly to the grid and chains 22-24, where the transport application is not relevant and the stationary applications are referred to as a) and b).

** Stationary applications for chains 17 to 19 were not included in the original list of options.

[1] The distributed power FC was modelled as a micro CHP FC system without the heat output. This is therefore representative only but does illustrate the important contribution heat use makes to distributed fuel cell systems running on conventional fuels.

[2] Including negative biomass emissions. If negative biomass emissions are not included, this value increases by 16%.

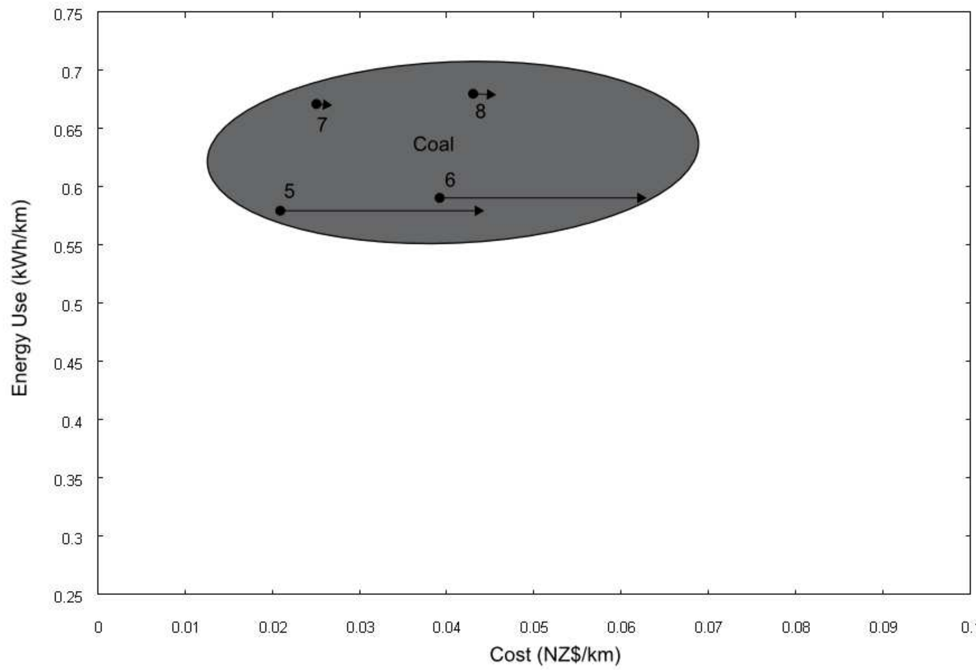

Figure D1 - Coal with CO_2 Costs Ranging from NZ$0 to $100 per Tonne

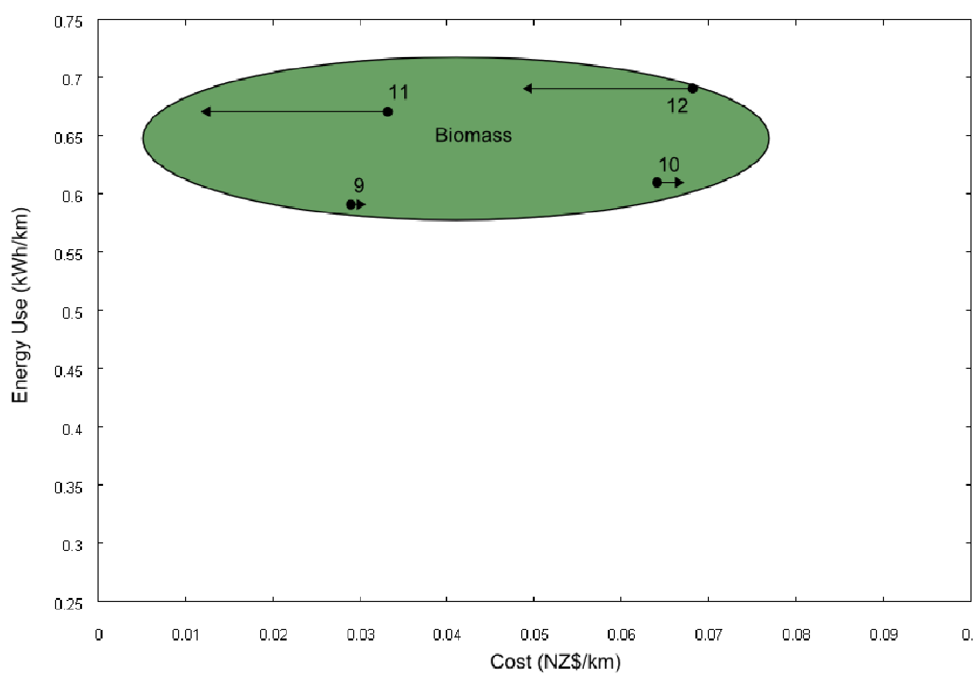

Figure D2 - Biomass with CO_2 Costs Ranging from NZ$0 to 100 per Tonne

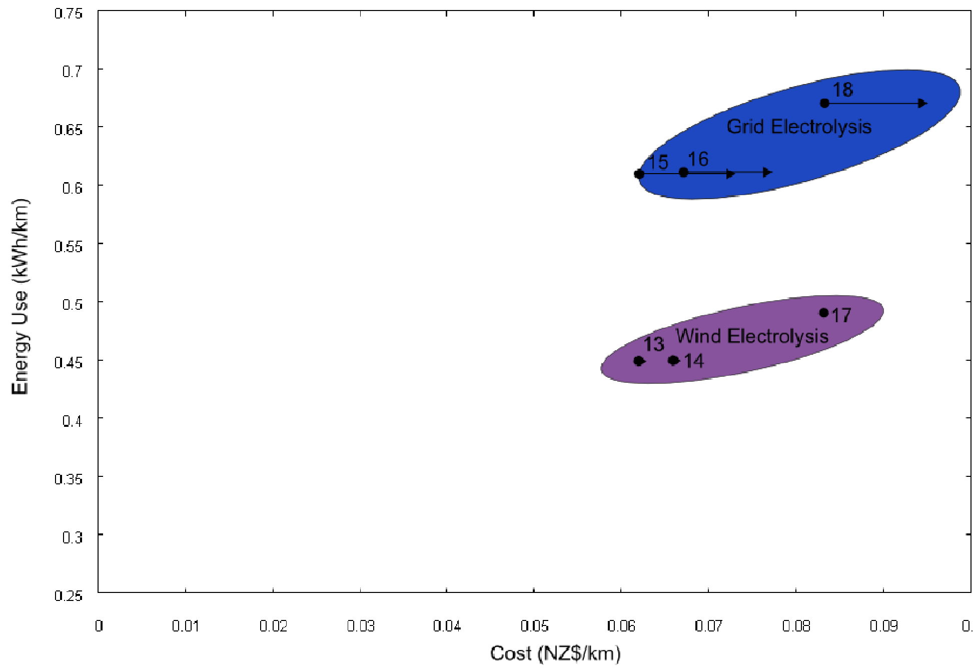

Figure D3 - Electrolysis with CO_2 Costs Ranging from NZ$0 to 100 per Tonne

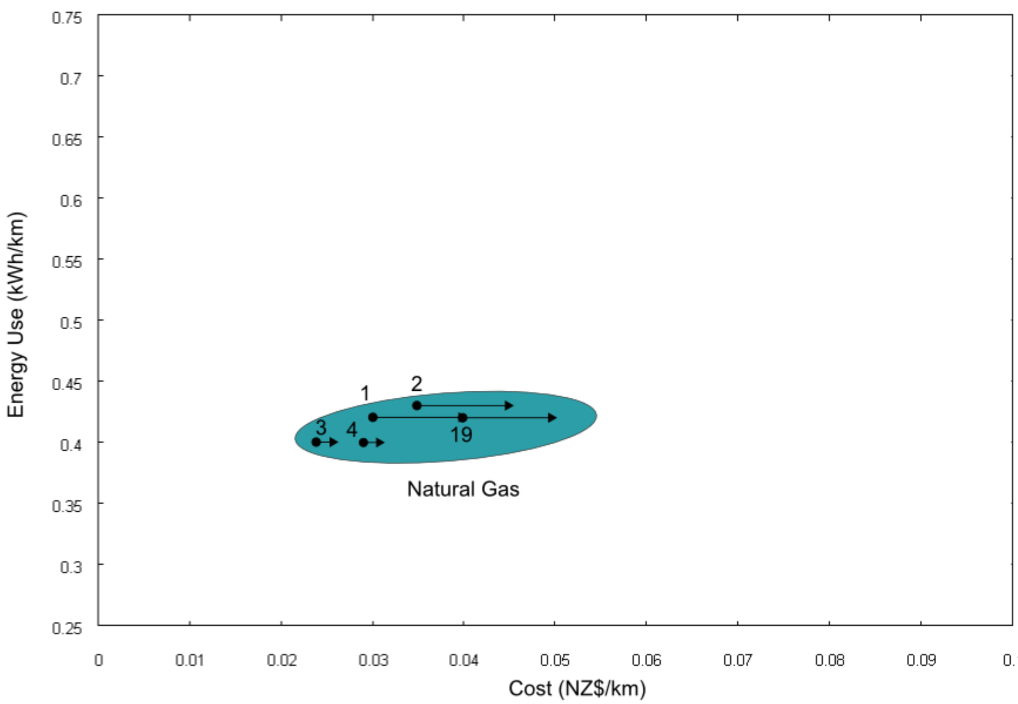

Figure D4 - Natural Gas with CO_2 Costs Ranging from NZ$0 to 100 per Tonne

Figure D4 shows the individual data points for the natural gas chains with and without CCS. The CCS / no CCS lines are inverted, (i.e. the energy use goes down when CCS is used). This apparent anomaly is due to the differences in plant size (844MW c.f. 3.8MW) between chains with and without CCS. Had a plant of a similar size been considered in the no CCS chain then this effect would not be seen.

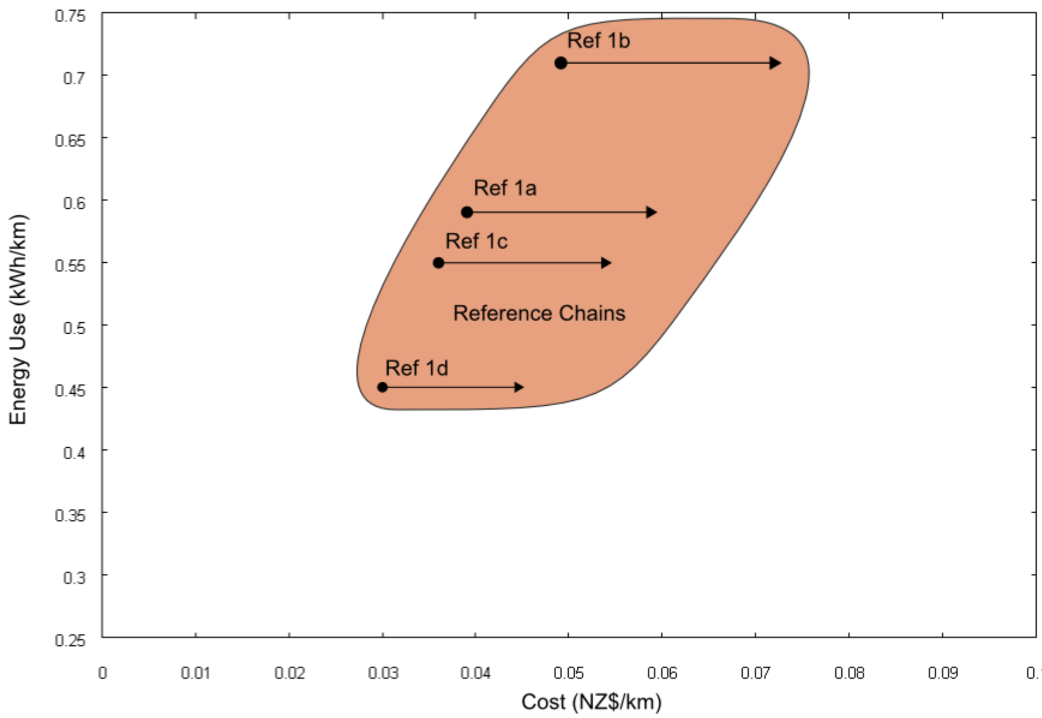

Figure D5 - Reference Chains with CO_2 Costs Ranging from NZ$0 to 100 per Tonne

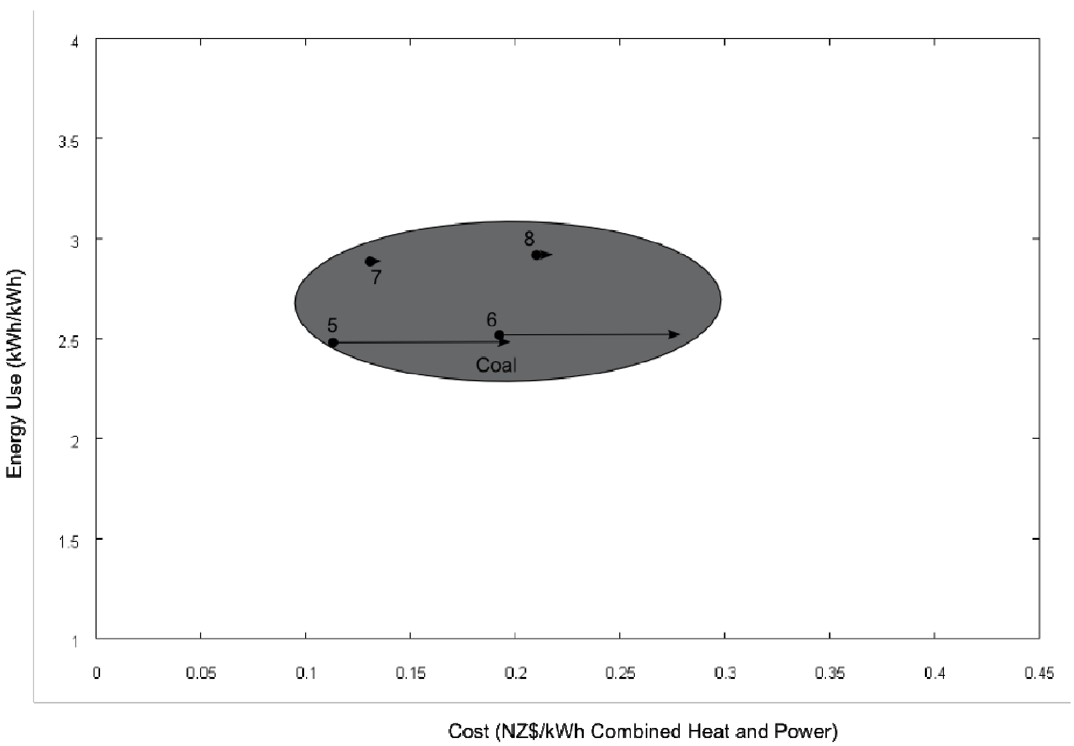

Figure D6 - Coal with CO_2 Costs Ranging from NZ$0 to $100 per Tonne for CHP

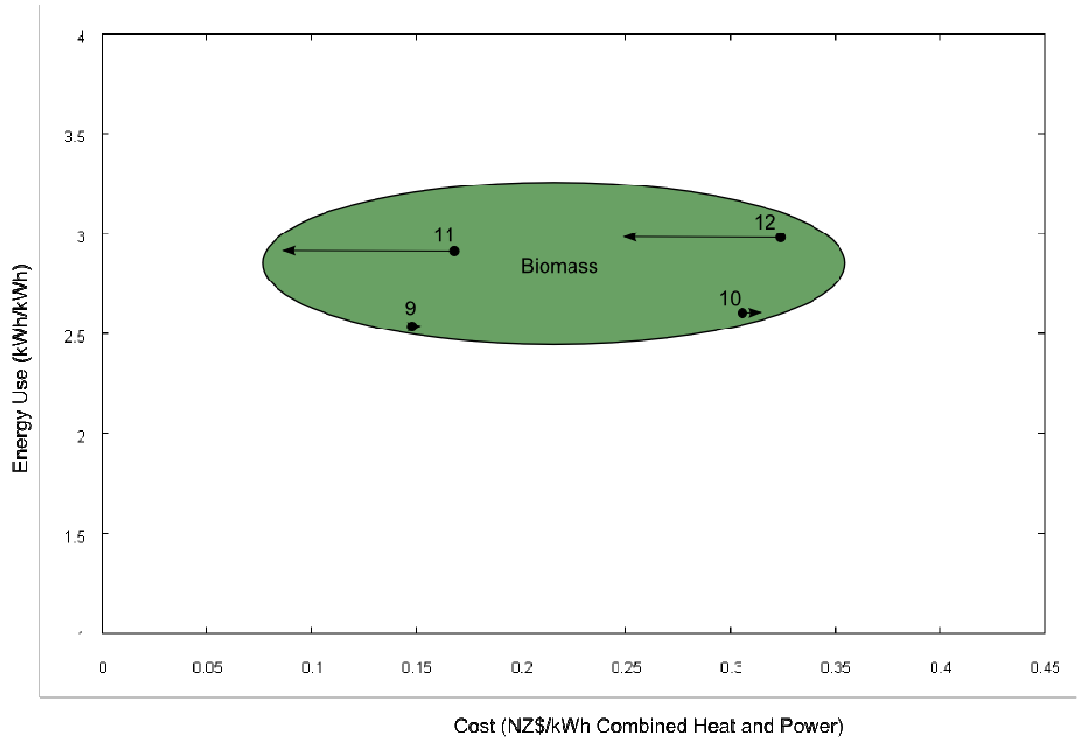

Figure D7 - Biomass with CO_2 Costs Ranging from NZ$0 to 100 per Tonne for CHP

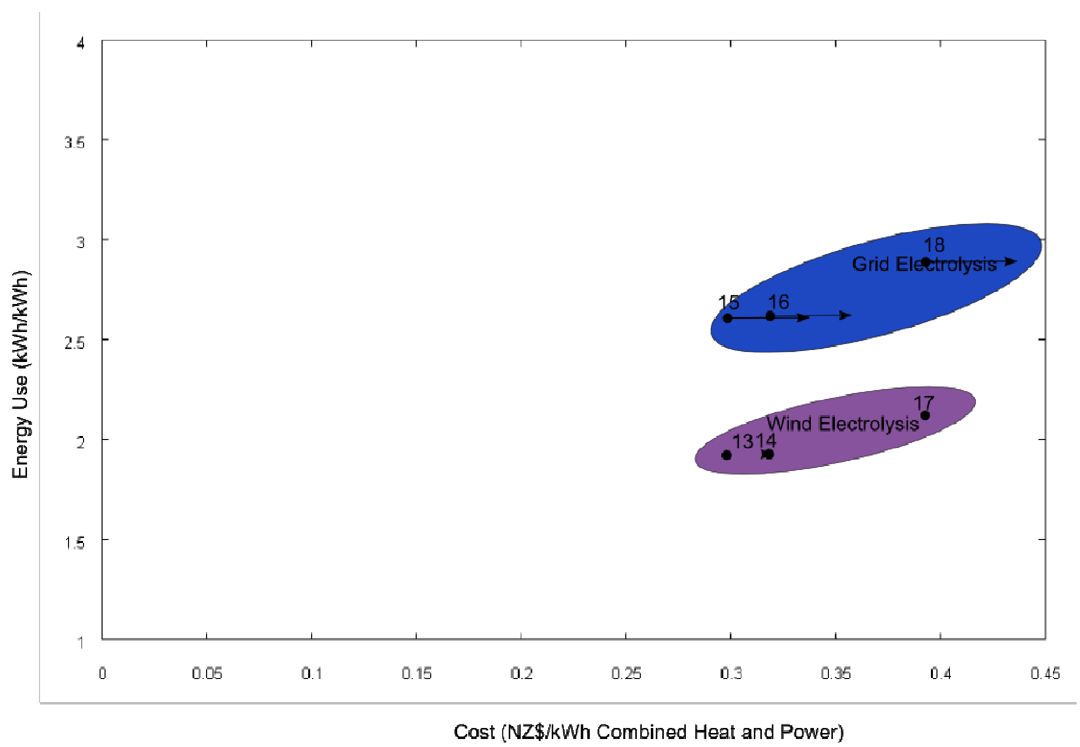

Figure D8 - Electrolysis with CO_2 Costs Ranging from NZ$0 to 100 per Tonne for CHP

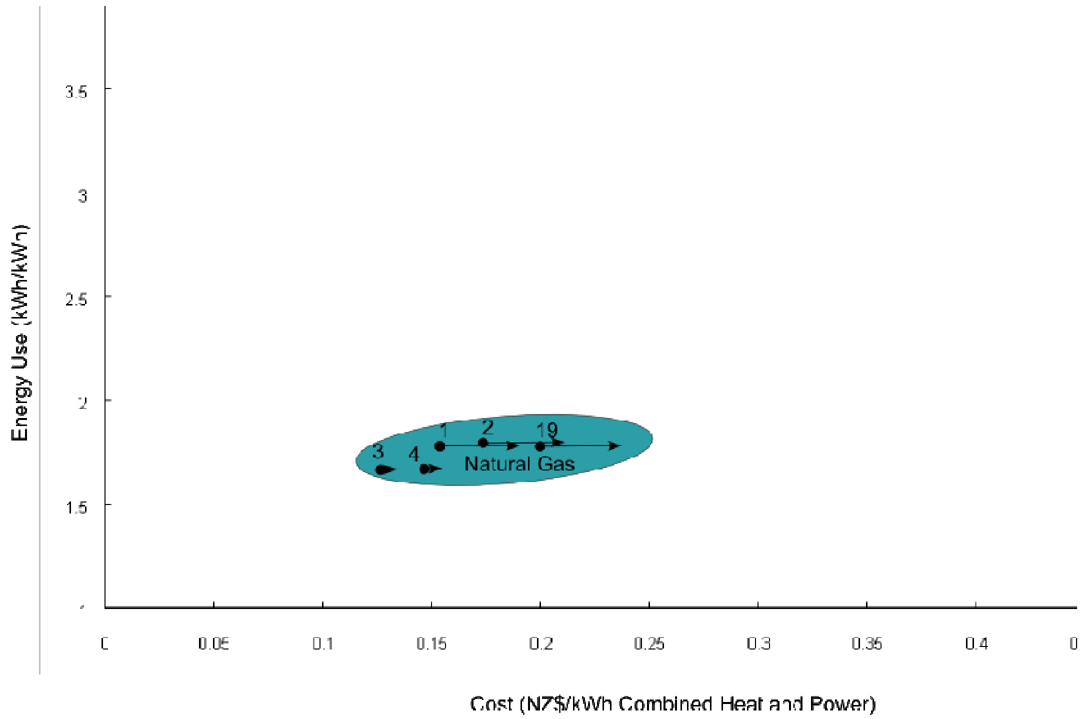

Figure D9 - Natural Gas with CO_2 Costs Ranging from NZ$0 to 100 per Tonne for CHP

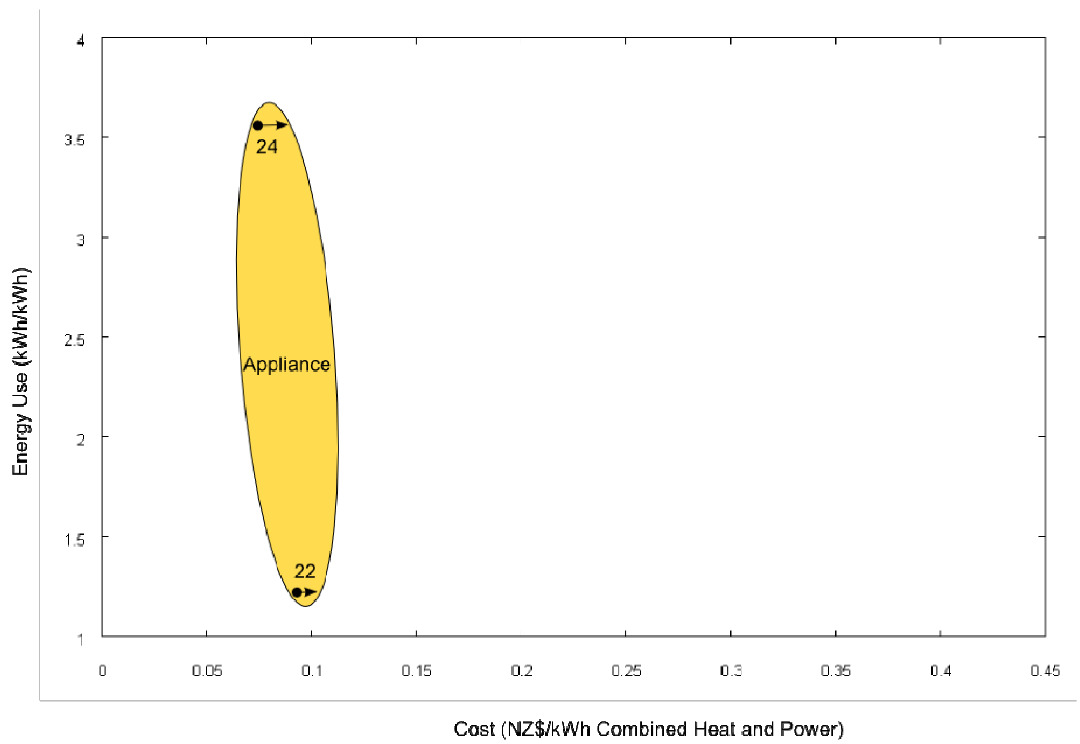

Figure D10 – "Appliance chains" with CO_2 Costs Ranging from NZ$0 to 100 per Tonne for CHP The LPG chain 23 was modelled using the same energy chain assumptions as natural gas (chain 22).

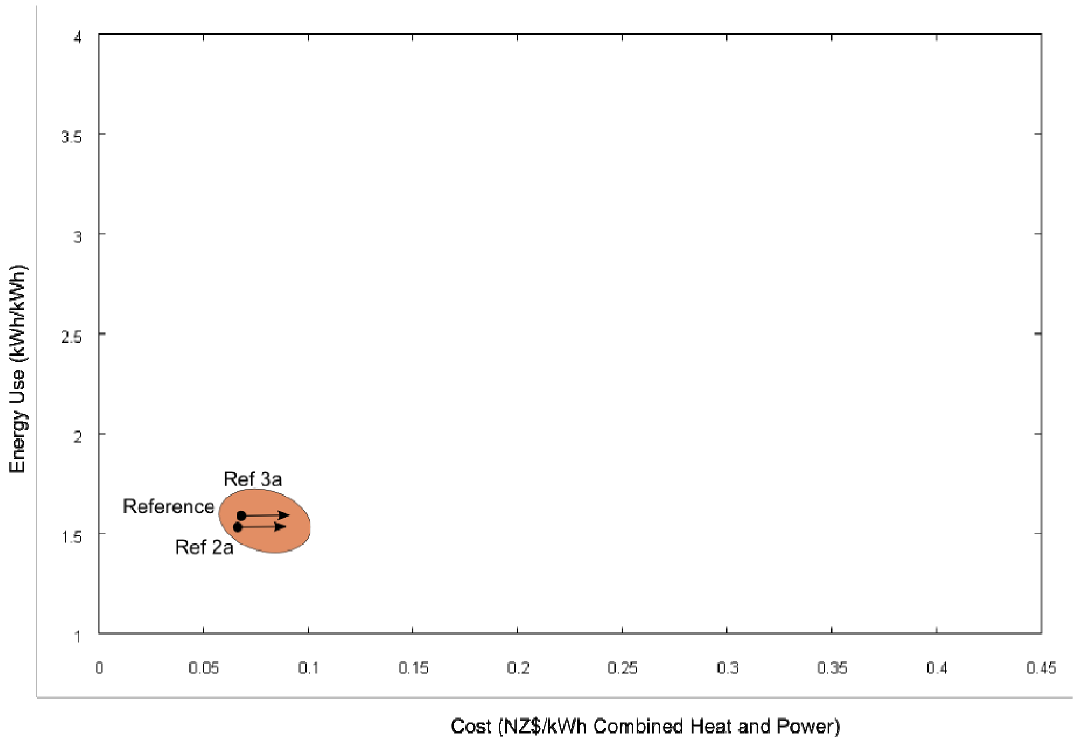

Figure D11 - Reference Chains with CO_2 Costs Ranging from NZ$0 to 100 per Tonne for CHP