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Hydrogen in New Zealand
Report 1 – Summary

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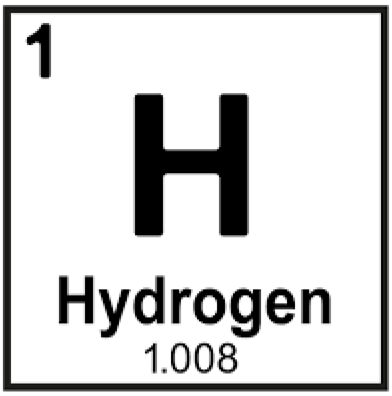

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Concept has undertaken a wide range of assignments, providing advice on market design and development issues, forecasting services, technical evaluations, regulatory analysis, and expert evidence.

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About this report

This study was sponsored by six organisations: Contact, Meridian, Powerco, First Gas, MBIE, and EECA. We would like to thank the many individuals within these organisations, and others from other organisations, who have provided valuable input into this study.

However, this report ultimately represents Concept's analysis and views (and any errors within it are our own), and the report should not be construed as representing the views of any of the six sponsor organisations.

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1 Introduction and Findings

The drive to decarbonise the world's energy systems is bringing about technological change as governments, suppliers and end users look for ways to replace fossil-fuel based energy with alternatives such as biofuels and renewable electricity. Hydrogen may have a role to play in the global energy transition as a potentially convenient and flexible way of storing and transporting energy for use in vehicles, homes, businesses and industrial applications.

This study examines whether hydrogen technologies could have a role to play in decarbonising the New Zealand economy, or in providing an export opportunity assisting decarbonisation of other economies.

This report summarises our findings and is supported by two other reports:

- Report Two – Analysis – full technical report
- Report Three – Background Research – collation of useful research material.

We approached our task by considering how the cost effectiveness of hydrogen compares to alternative means of decarbonising the New Zealand economy, with a focus on transport, industrial process heat, space, & water heating, and power generation. We have also considered the potential for New Zealand to export hydrogen to assist other countries to decarbonise.

Our principal focus has been on the economics of 'green hydrogen' – using renewable electricity to produce hydrogen from water – but we have also looked at hydrogen-from-hydrocarbons: splitting hydrogen from natural gas and using carbon capture and storage to minimise the associated CO_2 emissions.

We have analysed how costs stack up today, and project how costs may change 20 years from now. Our analysis compares hydrogen to other low-carbon alternatives – particularly direct electric options such as electric vehicles and electric heating.

Our key findings are:

1) Most of the technologies involved in hydrogen production and use are mature and well understood, and there is research and development activity internationally aimed at enhancing and extending hydrogen technologies and their real-world application.
2) The current cost of hydrogen production is high, both compared to fossil fuels and to more direct uses of electricity. This is due to capital costs and process losses involved in producing and storing hydrogen from electricity.
3) Hydrogen production costs are likely to fall in future if worldwide equipment production scales up and, potentially, due to changes in the profile of wholesale electricity and electricity network prices:
   - It may be possible to reduce hydrogen production costs by targeting periods of low electricity prices that could arise in an electricity system with a high penetration of renewable generation.
   - However, this lower-cost 'opportunistic' hydrogen production is expected to only satisfy a relatively small amount of New Zealand's demand for energy. Larger-scale hydrogen production would drive the need for new renewable power stations to be built, increasing the costs of hydrogen.
4) If production costs fall and carbon prices rise, then hydrogen could become cost-competitive with fossil fuels (such as natural gas and diesel). However, our assessment is that in most cases, hydrogen is unlikely to become cost-competitive with more direct uses of electricity such as

electric vehicles, electric process heat boilers, and heat pumps for space and water heating. This is because:

a) there are significantly lower process losses in direct electric options. For example, almost three times more renewable energy is required to power a hydrogen vehicle than an electric vehicle, and approximately twice as much renewable energy is required to fuel a hydrogen boiler or heater, compared to an electric boiler or heat pump; and

b) these direct electric technologies are also projected to enjoy significant cost reductions – e.g. electric vehicles are likely to continue to enjoy cost and performance improvements at a rate similar to that seen over the past decade.

5) Hydrogen potentially has some advantages compared to more direct uses of electricity that mean it could be competitive in some niche applications, such as 24/7 on-site freight-loading operations, and meeting energy demand for remote off-grid locations.

6) At high carbon prices (likely over \$3-400/tCO_2), hydrogen could become a cost-competitive fuel for firing gas turbines for peak or seasonal electricity generation. However, large-scale storage is problematic, and hydrogen-fired turbines may struggle to compete with other options such as biomass or over-building renewable generation. It is possible that if New Zealand develops a hydrogen export capability, diversion from export sales to powering hydrogen-fired generation during dry winters could be lower cost than dedicated facilities for delivering dry-year hydrogen, but we have not evaluated the possible economics in detail.

7) Using hydrocarbons to produce hydrogen could be lower cost than 'green' hydrogen for carbon prices up to \$500-600 per tonne CO_2 range, provided carbon dioxide can be captured and sequestered. However, this does not change the finding that hydrogen appears less competitive than direct use of electricity for most applications.

8) However, hydrogen may be more attractive for countries such as Japan because they do not have sufficient domestic renewable electricity generation potential to meet demand.

9) If Japan decides to decarbonise through importing renewable energy in the form of hydrogen (noting that it would face energy costs three to four times higher than other countries), it could be a significant export opportunity for New Zealand. However, exporting a meaningful amount of hydrogen to Japan would significantly draw upon our own developable resources and increase New Zealand electricity prices to some extent.

10) For comparison, we estimate that:

a) New Zealand will need to double its generation – the majority of which will need to be from wind and solar farms – to meet its own decarbonisation requirements via the direct electric route (triple via the green hydrogen route)

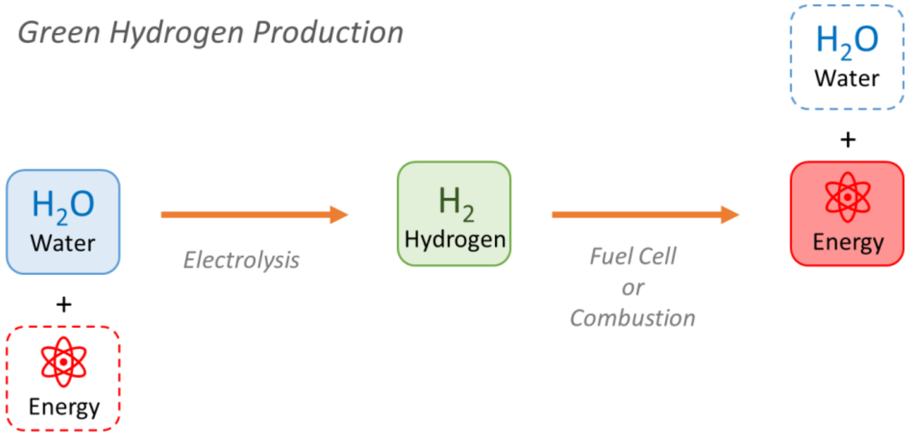
b) Japan will need to call upon foreign renewable generation 125 times greater than this extra New Zealand renewable generation, if it is to decarbonise completely through importing overseas green hydrogen.

This report provides insight on these findings, and we encourage you to review our analytical report if you would like a more in-depth information. The balance of this report is structured as follows:

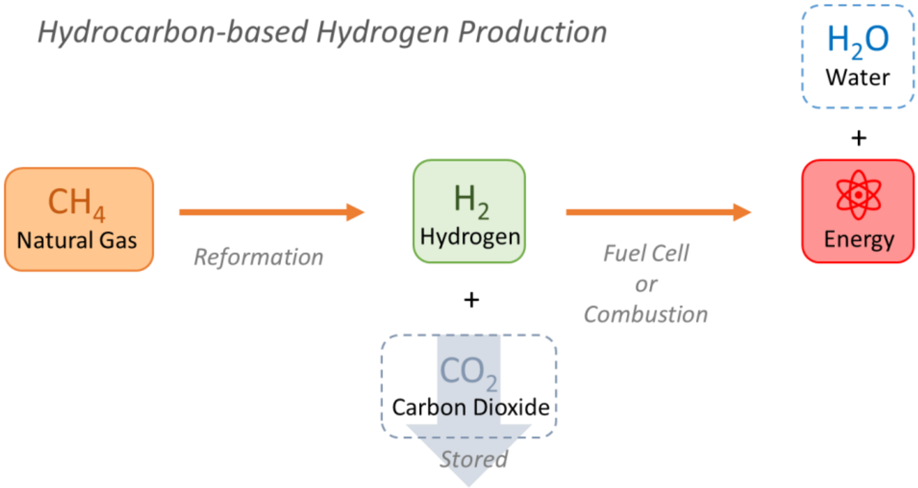
- Background – brief introduction to hydrogen and the applications we have considered
- Hydrogen cost estimates – our assessment of the cost of producing hydrogen
- Applications – assessment of the competitiveness of hydrogen for decarbonisation or export

2 Background

Hydrogen can be produced through electrolysis (using electrical energy to split water) and stored or piped for use in a fuel cell, burner or turbine. Fuel cells produce heat and electricity and emit only water vapour. Hydrogen combustion similarly emits only water vapour. Hydrogen energy chains are flexible and clean and, if the electricity is sourced from renewable generation, they can be carbon neutral – hence we refer to this as 'green' hydrogen.



An alternative method for producing hydrogen is by reforming natural gas (or another hydrocarbon fuel). If the carbon dioxide produced as a by-product of this process can be captured and stored, then this can also form a relatively low-carbon energy chain.



We have developed cost estimates for 'green' and hydrocarbon-based hydrogen and used these to see how hydrogen stacks up against fossil fuels in use today, and other low-carbon technologies that could compete with hydrogen.

Our cost estimates look at the present day, and project how things may change as technologies mature and markets evolve twenty years into the future.

We have taken our estimates of the cost of producing hydrogen and examined end-use applications with the greatest potential for decarbonising the New Zealand economy:

- transport – focus on heavy line-haul trucks
- industrial process heating – focus on intermediate heat raising
- space and water heating – focus on household-scale
- power generation – focus on utility-scale for flexible seasonal / dry-year generation

We also looked at converting natural gas pipelines to carry hydrogen and considered the prospects for exporting hydrogen.

While many hydrogen technologies are proven and well understood, full hydrogen-based energy chains are another story. We have used real-world data where possible, supplemented by range of assumptions, deductions and projections about how hydrogen energy chain would function.

There is considerable room for uncertainty, but we think the general thrust of our findings are robust. As hydrogen is a fast-evolving field, it would be useful to periodically update hydrogen cost estimates and assumptions about end-use applications.

3 Hydrogen Cost – Reference Estimates

We developed reference cost estimates that we can use to test hydrogen applications.

Each reference estimate is based on a production model and set of assumptions that can be adjusted to suit the application being tested – for example, to test transport we adjust for losses associated with compressing to higher pressures add we service station overhead costs.

3.1 Green hydrogen

Our reference estimate for producing hydrogen in New Zealand today is $8.91 per kg, including the cost of storage in a tank.

Our estimate is consistent with overseas research, albeit lower than most overseas estimates. This provides some comfort that our estimate is not too unrealistic.

For comparison with other fuels, $8.91 per kg translates to $63 per GJ or $0.23 per kWh. For reference the wholesale cost of natural gas is currently $6/GJ and the wholesale cost of electricity is approximately $0.075/kWh.

While comparison with other fuel costs is interesting, what really matters is how efficiently each fuel can be converted into something useful (such as heat or transport) – that is the question we turn to when considering hydrogen applications – detailed in section 4 later.

The components contributing to our hydrogen cost estimate are:

- electricity – including wholesale electricity costs, and network costs. Our reference estimate assumes a relatively large-scale facility able to access wholesale prices for electricity and commercial rates for network connection. These costs make up more than 75% of the cost of production.
- equipment – the capital and operating costs of electrolyser and storage equipment. Our reference estimate assumes hydrogen is placed in relatively short-term on-site bulk storage, and that an efficiently high rate of production is sustained (85% capacity factor). Equipment costs make up nearly a quarter of the cost of production.
- losses – process losses at the electrolysis and compression (for storage) stages add to the cost of production. We assume 30% and 10% losses respectively.

3.2 Future Green Hydrogen

There may be potential for significant reductions in the first two of these cost components into the future. To estimate what the cost of producing hydrogen may be 20 years from now, we updated our assumptions as follows:

- Wholesale electricity– we considered a scenario where New Zealand has a highly renewable electricity supply that causes prices to collapse when there is abundant production (e.g. strong wind, sun or rain). Hydrogen production is adjusted to only target these low-price periods.

  However, this low-cost 'opportunistic' hydrogen production is only likely to be an opportunity if hydrogen production does not make a material contribution to New Zealand electricity demand. If large-scale hydrogen production occurs, it will start to drive the need for additional renewable generation[1], and the wholesale electricity cost component of hydrogen production will rise to reflect that fact.

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[1] For comparison, we project that to decarbonise New Zealand via direct electric transport and process heating will require a doubling of New Zealand's generation. To decarbonise using hydrogen transport and process heat produced by renewable electricity will require a tripling of New Zealand's generation.

- Electricity network – we assume that future, more cost-reflective electricity network tariffs will enable optimised hydrogen production to lower this component of hydrogen production costs.
- Hydrogen equipment – we consider a scenario where worldwide production scales up considerably, which leads to electrolyser and storage capital cost reductions of 50% and 40%, respectively.

We also considered the cost of producing hydrogen for a variety of different use cases:

- Power to gas – injecting hydrogen directly into the gas network as a blend with natural gas. This avoids storage costs and compression losses. Two sub-cases were considered: a large-scale transmission-connected electrolyser facility ('Tx-injection'), smaller-scale electrolysers connected to the electricity distribution network ('Dx-injection').
- Bulk storage – our base case use case detailed above, and consistent with producing hydrogen for use at an industrial process heat facility.
- Service station – producing hydrogen for transport, which incurs greater compression losses, and adds service-station overhead.
- Off-grid – producing hydrogen for bulk storage but avoiding an electricity network connection. On the flip side, this requires greater storage, and results in the electrolysers operating at lower capacity factors.

The results of the analysis are shown in Table 1.

Table 1: Projected hydrogen production costs ($/kg)

	Current	Future	
		Opportunistic	Large-scale
Gas Dx injection	7.57	2.97	5.93
Gas Tx injection	6.80	2.67	5.33
Bulk storage	8.91	4.65	6.94
Service station	11.30	6.55	9.11
Off-grid bulk storage	12.56	9.22	9.22

Tech_Eval_v05.xlsm

Interestingly, even in the small-scale opportunistic hydrogen production case, we found it wasn't economic to aggressively target low electricity prices because that would require building comparatively large storage facilities to make the most of low-price periods while avoiding high-price periods. Further, operating less frequently increases the capital recovery component of hydrogen production. (An electrolyser used only half the time has a capital recovery component that is twice as high as one that is operated constantly).

Power-to-gas can produce hydrogen more cheaply as it is not constrained by storage limitations – i.e. it can simply inject hydrogen into a gas network as and when it was produced – and can therefore do more aggressive targeting of production to low electricity price periods.

In all situations, if hydrogen starts to increase the requirement to build renewable generation, the ability to undertake low-cost 'opportunistic' hydrogen production will substantially reduce.

We think our assumptions are quite favourable, and it's possible that future cost reductions will be less material than projected here. On the flip side, we are dealing with long timeframes and no one can predict with confidence how technologies will advance. On balance, we think our estimates are about right for our intended purpose of testing the potential for hydrogen to be competitive with other means of decarbonisation.

3.3 Hydrogen from Hydrocarbons

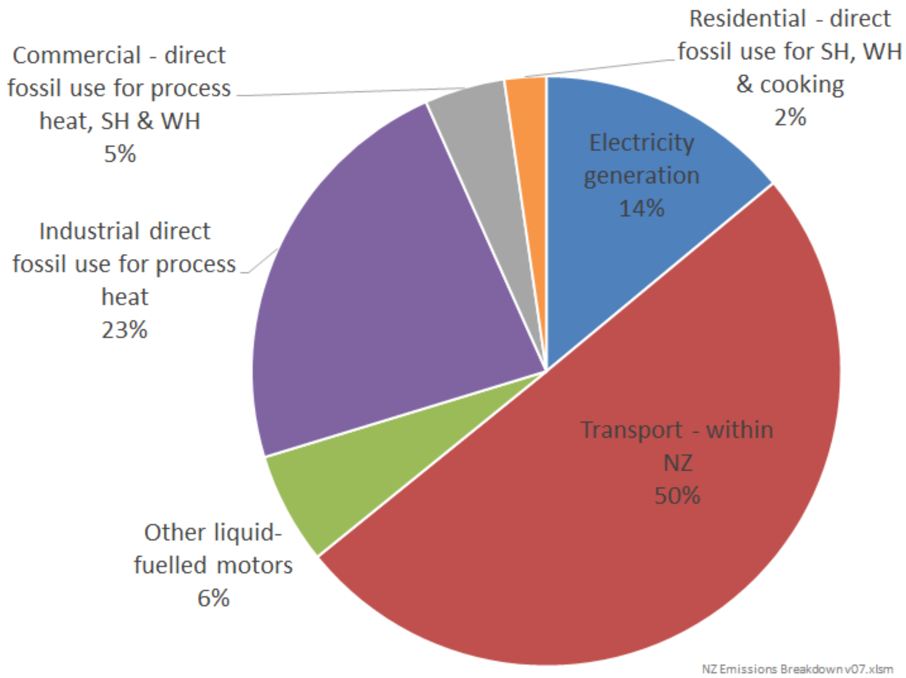
We also prepared a reference estimate of $2.7 per kg ($19 per GJ) for using natural gas to produce hydrogen through a petrochemical process called steam methane reforming.

Our estimate assumes very large-scale production with carbon capture and storage (CCS). It excludes hydrogen storage costs, because production is assumed to be fed straight into a transmission pipeline.

We assume carbon costs of $100 per tonne CO_2 for this estimate, because CCS wouldn't be economic with a low carbon price. The carbon price is relevant because we assume CCS only removes 75% of carbon dioxide, with the balance attracting an emissions obligation.

4 Hydrogen applications

New Zealand has a unique profile of energy-related greenhouse gas emissions, with transport dominating and our electricity generation making a smaller contribution than in most other countries.



Source: Concept analysis of MBIE data

Hydrogen technologies could potentially be used to displace fossil fuel use in all these areas. Our study considers how well hydrogen stacks up against other decarbonisation options such as direct use of electricity for heating, battery-electric vehicles for transport, biofuels for process heat, and wind or solar for electricity generation. We also consider the potential to export hydrogen to renewable-poor countries.

4.1 Transport

Road transport is the largest and fastest growing source of transport-sector emissions in New Zealand. Battery-electric vehicles are poised to become competitive with internal combustion engines for *light* road transport, but their economics may be more challenging for heavy transport due to weight and range limitations (noting that the heaviest vehicles are also those which tend to drive the longest distances).

We developed a heavy freight transport cost model to compare the cost effectiveness of diesel, battery-electric and hydrogen heavy linehaul trucks. While diesel vehicles dominate heavy road freight, several manufacturers have battery-electric trucks in pre-production and there are claims of hydrogen trucks being in development. This means we do not have real-world data for these alternative technologies, but we have been able to develop estimates based on available data points.

The key differences between the three technology options are fuel costs and vehicle capital costs.

With respect to fuel costs, EVs enjoy an advantage from superior inherent vehicle fuel efficiency, coupled with lower delivered fuel prices – noting that both HVs and EVs source the same primary fuel (renewable electricity) but there are material energy losses and additional capital costs associated with converting this renewable electricity into hydrogen. We project this will result in the future fuel costs for EVs being less than a third of the fuel costs for diesel and hydrogen vehicles.

We estimate that heavy EVs currently cost 45% more than diesel trucks, and that heavy HVs cost 180% more. We project that there are greater opportunities for cost reductions for HVs such that in 20 years' time the capital cost penalty relative to diesel trucks will have fallen to 10% and 45%, respectively.

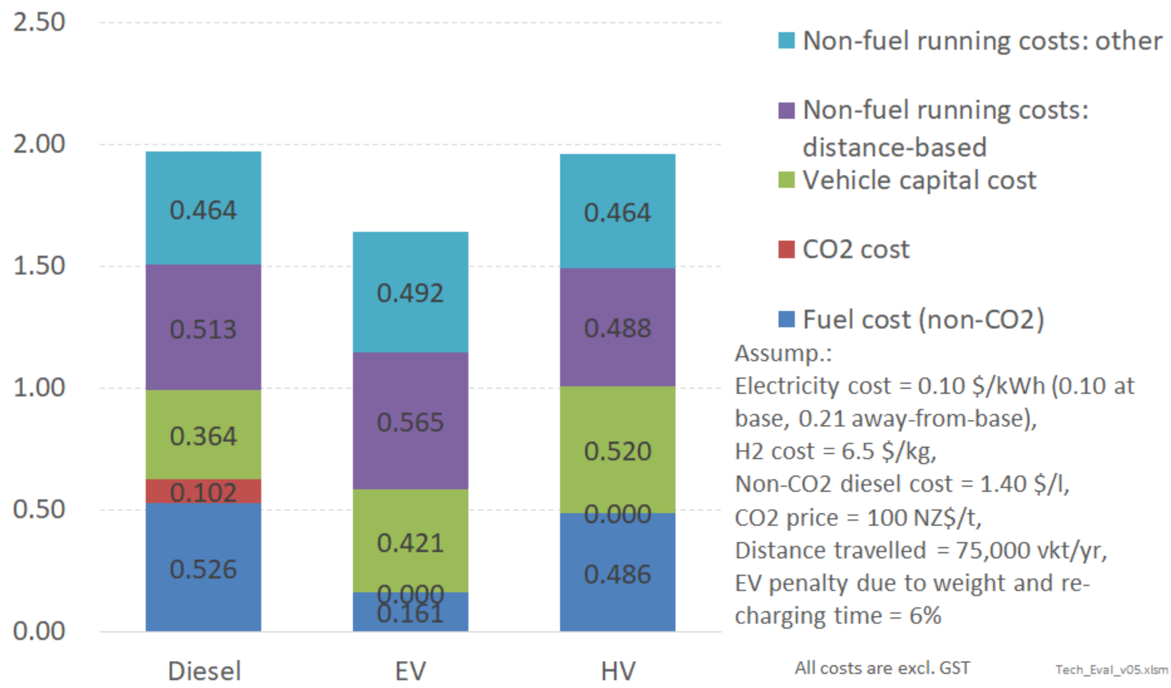
We have assumed the heaviest class of battery-electric trucks currently suffer an average 18% 'productivity penalty' compared to diesel and hydrogen due to unproductive downtime while recharging, and reduced payload due to the weight of the battery. (i.e. 18% more electric trucks will be needed to perform the same heavy freight transport service). This penalty will be greater for those heavy freight vehicles that travel longer-distance than average (rising to 38% for vehicles that travel twice the average annual distance), but less for those that travel shorter distances.

However, future developments in battery technology are projected to significantly reduce this penalty.

Further this productivity penalty is only a significant issue for the very heaviest of New Zealand's freight vehicles, accounting for less than 30% of heavy freight fuel consumption and approximately 5% of New Zealand's transport emissions.

Figure 1 presents our central projection of the future relative lifetime economics of heavy freight vehicles.

Figure 1: Modelled future relative costs of different heavy transport options – assuming opportunistic hydrogen production ($/vkt)



This analysis suggests that both hydrogen and electric vehicles are likely to be lower cost than diesel – albeit with EVs more likely to be the least-cost decarbonisation option for the majority of New Zealand's road transport requirements: light and heavy. (Noting that the relative economics of EVs improves for lighter vehicles that don't travel such long distances).

That said, hydrogen may be better in certain niche return-to-base or never-leave-base operations (e.g. forklifts, port crane operations), and we understand that the extra weight of electric buses can cause issues on some bus routes. We have not examined the economics of these more specialised situations.

However, the vehicle capital cost and fuel efficiency assumptions embedded within Figure 1 assume large-scale world-wide uptake of both EVs and HVs to drive the projected cost reductions. It remains to be seen whether this does indeed occur, or whether the world heads down one transport technology path. For there to be widespread uptake of both technologies would either require countries to invest in two sets of re-fuelling infrastructure (for EVs and HVs), or for one part of the world to head down the hydrogen path, and the other the battery electric path.

In this respect, if the rest of the world heads down the hydrogen path, New Zealand will have no choice but to follow. This raises some tricky public policy issues around investing in refuelling infrastructure to facilitate the uptake of low-carbon transport.

Our analysis indicates that the current lack of away-from-base re-fuelling infrastructure is going to be a major impediment to the uptake of heavy EVs or HVs – irrespective of whether the theoretical economics suggest an option is close to being economic. In this respect, we think it is relatively unlikely that high-power battery charging *and* hydrogen fuelling infrastructure will both be deployed at a scale needed to changeover New Zealand's heavy transport fleet. The network economies of transport strongly suggest that one technology will emerge as the dominant technology. (At least for transport requirements using public highways and relying on public re-fuelling infrastructure, rather than return-to-base or never-leave-base operations).

The winner of the race to replace diesel may ultimately be determined by how quickly and successfully overseas vehicle manufacturers improve the value proposition for each type of truck. For now, there appears to be much more research and development going into battery electric, with current rapid uptake of *light* EVs driving battery cost reductions that will also benefit heavy EVs.[2] We also think it significant that North America is a relatively 'renewables-rich' country, and China is more aggressively pursuing electric vehicles than its hydrogen initiatives – although we note that there is debate in both countries as to the best option going forward.

4.2 Industrial process heat

In recent years, industrial process heat has overtaken electricity generation to be New Zealand's second largest source of energy-related emissions.

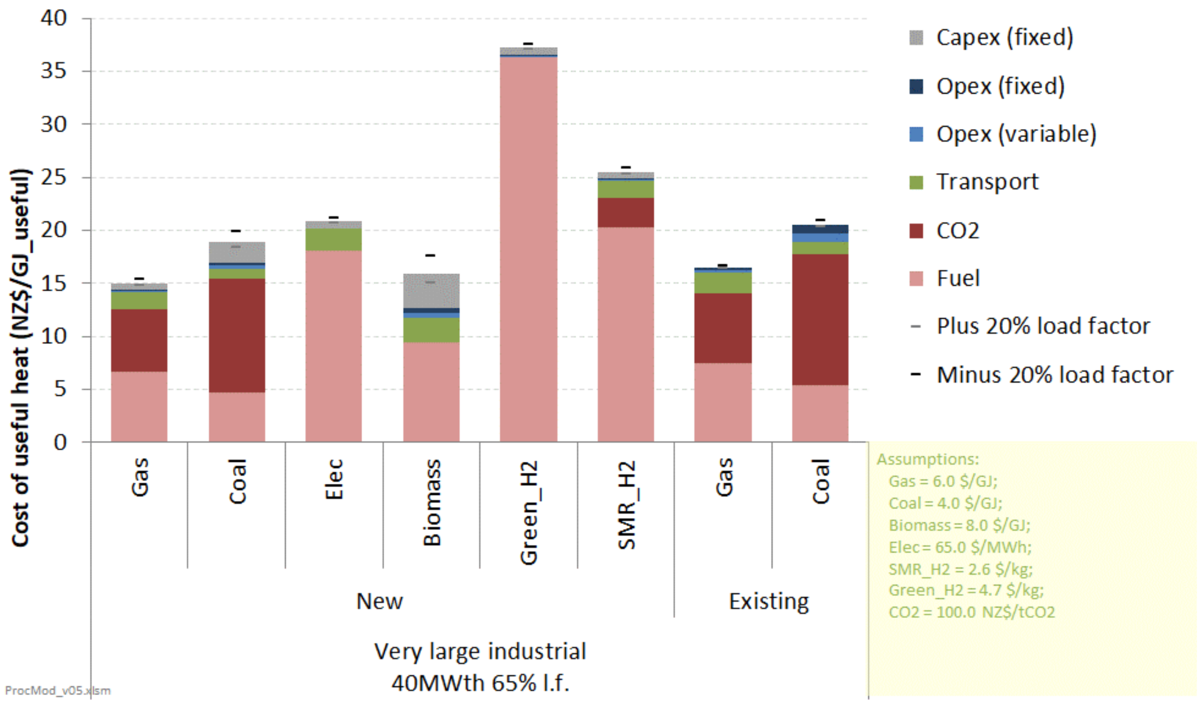
A significant share of process heat emissions come from uses where hydrogen is not an option because gas is a feedstock as well as a fuel. However, hydrogen could be used for other process heat applications. We have focussed on intermediate process heat (using a boiler to raise steam to between 100 and 300°C) using very large boilers, as these boilers currently provide the principal heat requirement for food, pulp, paper and print – our biggest sources of process heat emissions.

We compared the economics of hydrogen-fuelled boilers (both green hydrogen and SMR+CCS hydrogen), with gas, coal, diesel, electric and biomass.[3] For green hydrogen we have assumed on-site production and storage. Figure 2 presents the results of this analysis for a scenario with carbon prices of \$100/tCO_2.

[2] For more information, refer Concept Consulting, *Hydrogen in New Zealand, Report 3 – Research*, Chapter 11 (Worldwide interest in hydrogen).

[3] We have not considered the alternative approach of using a hydrogen fuel cell for combined heat and power because this is a more specialised application with comparatively high capital costs and low heat raising efficiency.

Figure 2: Process heat economics for very large industrial boilers – for a situation of opportunistic green hydrogen production



Recognising that site-specific factors can vary; this analysis nonetheless provides the following findings:

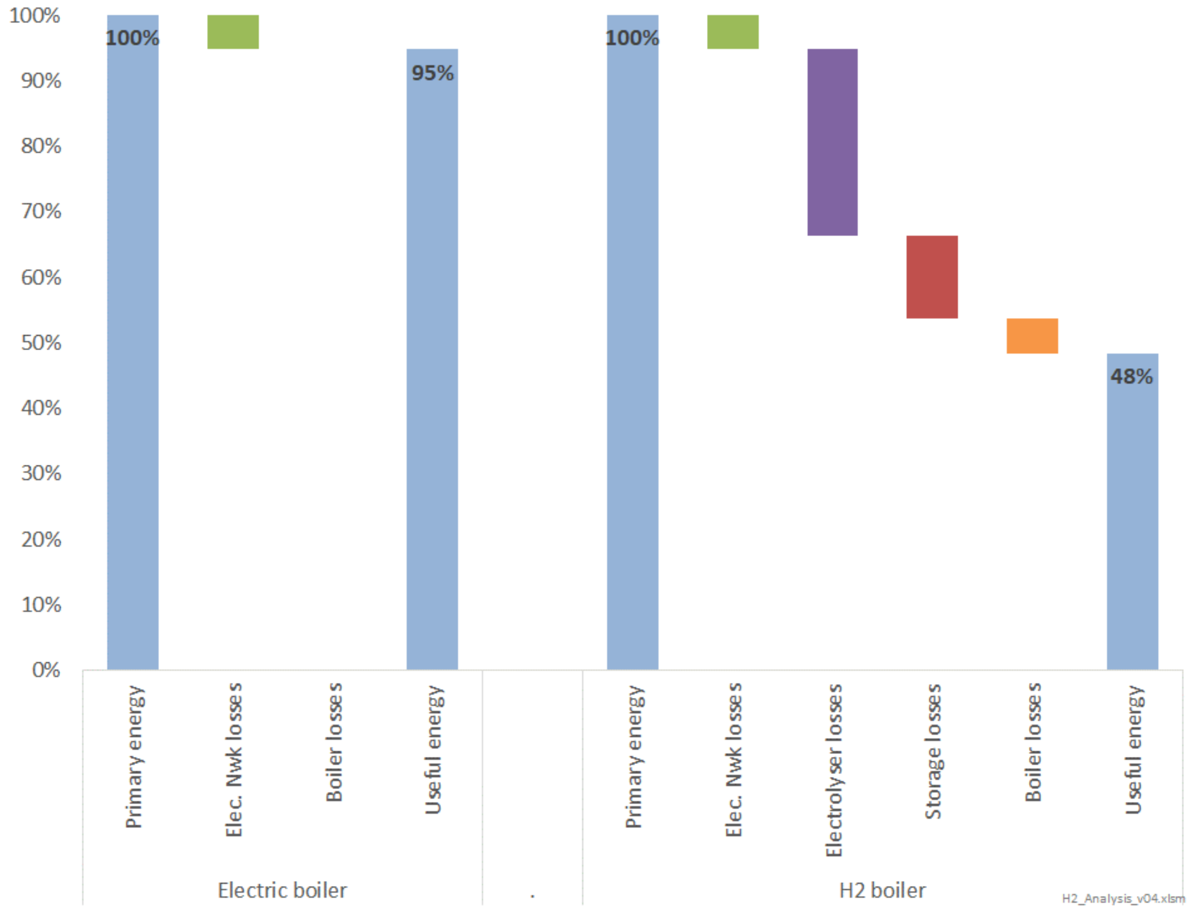
- Gas is competitive where available, even at $100/tCO_2$
- Coal is starting to become uneconomic at this carbon price relative to direct electric and biomass options. (Noting that there can be significant site-specific variations for all three options).
- Hydrogen is not projected to be competitive relative to the other low-carbon options: direct electric and biomass. There is no carbon price which will alter this evaluation.

  Further, to the extent that large-scale hydrogen production drives the need for new renewable generation, thereby increasing the wholesale electricity component of hydrogen production, the relative economics of green hydrogen as an industrial process heat fuel will become even more challenging. We have not shown the graphs with these higher green hydrogen costs as they do not change the fundamental conclusions.

As with transport, the challenges for green hydrogen are the process losses and capital costs associated with producing and storing hydrogen from electricity. These outweigh the benefits of being able to target production to times of low electricity and network prices.

The dynamic of energy losses is illustrated in Figure 3, which illustrates that twice as much primary renewable electricity is required to power a hydrogen-electrolyser-fuelled boiler as an electric boiler.

Figure 3: Comparison of energy losses between electric and green-hydrogen-fuelled boilers



This dynamic of process losses and capital costs also explains why it is hard for SMR+CCS hydrogen to compete with natural gas, except at very high CO_2 prices.

4.3 Space and water heating

Direct use of fossil fuels for space and water heating accounts for 4-5% of New Zealand's greenhouse gas emissions. We have focussed on household-scale applications and compared hydrogen with natural gas and electric heat pumps.

We assume hydrogen is delivered via converted natural gas pipelines. Hydrogen can be blended into existing pipelines, but only up to a point. Beyond around 10%, a complete changeover to hydrogen is a more likely approach. This requires coordinated changeover and inspection of all end use appliance to ensure safe operation. Our estimate assumes changeover costs are recovered via a small uplift to gas network prices.

Based on our assessment, a changeover from natural gas to hydrogen does not become economic until carbon prices reach \$650/tCO_2.

However, switching from gas to electric heat pump options is projected to be economic at much lower carbon prices

Appliance efficiency is a key driver of the relative economics of heat pumps versus natural gas or hydrogen appliances. While condensing boilers can have an efficiency as high as 90%, heat pump efficiency can be as high as 350% for space heating and 130% for water heating. These very high efficiencies reflect that electricity is used to power a process for extracting ambient heat energy, rather than as a direct energy source of heating.

The low end-to-end process efficiency that hampers hydrogen in other applications becomes a more acute handicap when compared to the very high efficiency of heat pumps – almost six times as much renewable electricity is required to heat a home with green hydrogen compared to a heat pump space heater (water heating is a less extreme comparison – just over twice as much renewable electricity is required for the hydrogen option).

4.4 Power generation

Power generation emissions vary year by year but accounted for a (small by international standards) 14% of New Zealand's emissions in 2016.

Our modelling suggests that, setting aside cogeneration plant, approximately half of emissions will come from baseload fossil-fuelled plant, and half from fossil-fuelled plant used to provide hydro-firming, seasonal (winter) generation and within-day peaking.

Hydrogen could be used to power modified gas turbines, which could be used to displace carbon-emitting forms of generation. In principle, it doesn't make sense to use hydrogen to displace *baseload* generation as green hydrogen is produced using baseload electricity.

The most plausible niche for hydrogen is as a way of storing energy at times of low electricity prices for use to power peaking generation that operates at times of higher prices. We have considered two possibilities – underground storage at the Ahuroa facility, and ammonia storage. These are lower cost options than tank storage for long-term, high-volume applications.

We found that ammonia storage is relatively expensive, with a cost of approximately \$50 per GJ. At this cost, a very high carbon price of around \$750/tCO_2 would be required to compete with natural gas.

Underground storage is less costly and *based on fuel costs alone* could potentially be competitive with natural gas with a carbon price as low as \$200/tCO_2.

However, there are several other non-fuel-cost factors which appear likely to significantly increase this threshold CO_2 price for using hydrogen stored in Ahuroa as a cost-effective option for meeting New Zealand's peaking energy needs:

- Existing gas turbines cannot simply switch to burning hydrogen. Given that hydrogen turbines are at an experimental stage it is not clear the scale of investment required to re-power existing turbines or build new turbines.
- Ahuroa could require investment to make it hydrogen-capable. This could include treating the reservoir to kill bacteria that could turn hydrogen into hydrogen-sulphide, and upgrading compressors.
- Hydrogen has a lower volumetric energy density than natural gas, so Ahuroa's capacity to store energy in the form of hydrogen would be materially lower (less than a third) than its capacity to store energy as natural gas. As well as reducing the effectiveness of this option to meet seasonal and dry-year flexibility requirements, it will increase the cost as the fixed costs of Ahuroa will be spread over a smaller quantity of GJ.

Given these costs, hydrogen-fired turbines may struggle to compete with other low-carbon options for meeting dry-year requirements such as biomass or over-building renewable generation.

A third potential opportunity for hydrogen to be used to provide dry-year electricity is if New Zealand develops a hydrogen export capability. In such a situation, hydrogen could potentially be diverted from export sales to powering hydrogen-fired generation during dry periods – noting that

New Zealand's winter peak demand (when dry-periods drive the need for back-up fossil generation) coincides with the lower summer demand period in major north Asian markets such as Japan, and South Korea. This export diversion option could potentially be lower cost than developing dedicated hydrogen facilities to provide dry-year energy.

However, the economics of such an option will rely on New Zealand first developing a significant hydrogen export capability, and a future international 'spot market' for hydrogen to emerge. As such, we have not considered the potential economics of this option in any detail.

4.5 Export

While much of the world appears to have sufficient land area to meet their own decarbonisation needs[4] – albeit requiring a reasonably large amount of land area to be converted to producing renewable electricity – there are some countries which are relatively 'renewables-poor'. Japan and South Korea particularly stand out as having insufficient available land for producing their own renewable electricity.

If these renewables poor countries have limited options for importing renewable electricity from adjacent countries via electricity transmission lines, and if they are unable (or unwilling) to use nuclear power to generate low-carbon electricity domestically, importing renewable electricity in the form of hydrogen appears to be the only other option for decarbonising their economies.

Hydrogen can be transported internationally by ship, either as liquified hydrogen or using ammonia or toluene as a carrier medium. This makes hydrogen production a potential avenue for exporting New Zealand's renewable energy advantage to renewables poor countries such as Japan or South Korea.

There are Japan-Australia and Japan-Brunei partnerships working to set up limited importation of hydrocarbon-based hydrogen to Japan as a potential stepping-stone to green hydrogen import. These have much lower cost than New Zealand green hydrogen, but also much lower environmental merit – particularly as at this demonstration stage they do not include carbon capture and storage.

While expensive (energy services will cost at least three to four times as much as 'renewables-rich' countries going down the direct electric route), importing hydrogen could nonetheless be an attractive option for some renewables-poor countries and it's possible a market for hydrogen will emerge.

For comparison, we estimate that:

- New Zealand will need to double its generation – the majority of which will need to be from wind and solar farms – to meet its own decarbonisation requirements via the direct electric route (triple via the hydrogen route).
- Japan will need to call upon foreign renewable generation 125 times greater than this extra New Zealand renewable generation, if it is to decarbonise completely through importing overseas hydrogen.

The scale of Japanese demand alone suggests that there would be demand for New Zealand hydrogen – even if Australian solar could produce hydrogen more cheaply than New Zealand solar or wind.

From a New Zealand production point of view, the attractiveness of hydrogen export would be weighed up against domestic uses (such as electrifying transport) – noting that developing renewable generation for hydrogen export will 'use up' some of our developable renewable

[4] These relatively 'renewables-rich' areas include North & South America, Africa, much of Europe, the Middle-East, and much of mainland Asia (but not Southern or South-Eastern Asia).

resource and increase electricity prices to a certain extent – and other opportunities for exporting energy-intensive products (such as aluminium).

Export would likely require steady, large-scale production to be viable due to the high cost and limited flexibility of liquification and ammonia conversion technologies. The associated electricity demand could be material on a New Zealand scale such that export would need to be coordinated with new supply (or retirement of a large user such as the Tiwai smelter). We estimate the delivered cost of green hydrogen produced in New Zealand and shipped to Japan could be around $44 per GJ by 2040. This compares to liquified natural gas (LNG) prices of approximately $14 per GJ, which means New Zealand green hydrogen would be competitive at a carbon price of around $550/tCO$_2$.

If international hydrogen proof-of-concept trials look to extend in future beyond hydrocarbon-based hydrogen, New Zealand could be an attractive location due to our existing high penetration of renewable electricity production.

If an overseas company wishes to invest in a hydrogen production facility in New Zealand, there does not appear to be any market failure or other factor which would prevent such a commercial development.