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Modelling hydrogen fuel distribution

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The global transport sector is facing pressure to change its fuel mix due to the need to reduce greenhouse gas emissions and avoid potentially higher oil prices. Graham et al. (2008) assessed the potential contribution of various alternative fuels in Australia under alternative carbon and oil price scenarios. It is apparent that vehicle electrification is an important strategy for reducing emissions in transport and there are two main approaches. The first is use of on-board batteries to store electricity drawn directly from the grid (assuming electricity is steadily decarbonised). A second path to electrification is use of hydrogen fuel cells.

In considering these two different paths to electrification of transport vehicles, the major advantage of hydrogen is that it provides a similar travel range to current vehicles. The major disadvantage is that it lacks the equivalent fuel distribution infrastructure of conventional fuel or of the electricity grid if using batteries for storage. This paper focuses on the problem of building distribution infrastructure for hydrogen. Since we already have technologies for converting other energy sources into hydrogen (e.g. electrolysis, gasification and steam reforming) at a competitive cost relative to conventional automotive fuels, and because we also have fuel cell vehicles available in the market (notwithstanding the need to reduce costs), the problem of fuel distribution would seem to be the most pressing issue facing the future of the industry.

A number of studies have contributed to the literature on the distribution of hydrogen fuel. Yang and Ogden (2007) studied the relative merits of three alternative delivery systems: compressed gas in trucks, liquid gas in trucks and pipelines. Compressed gas trucks were found to be ideal for low consumption markets at a short distance from the hydrogen production site. However if the consumption at the delivery node was high then pipelines were preferred no matter what the delivery distance was. If the distance was large but the consumption at the delivery site was moderate then liquid gas distribution in trucks was preferred. Mintz et al (2006) came to similar conclusions. These differences in the optimal distribution infrastructure arise from different combinations of fixed and variable costs for the three distribution technologies that may result in economies of scale or distance or both.

Pigneri (2005) studied an additional distribution option, which is to supply electricity to an electrolyser directly at the refuelling station, and compared this to compressed gas trucks and pipelines. He found that there were cost advantages in the strategy of using the electricity grid as the main distribution system, since this avoided building a pipeline that would be under-utilised for many years. However, if the market penetration was above 25 percent the other distribution options were more cost effective. In the choice between pipelines and compressed gas in trucks, pipelines were found to be superior.

Different hydrogen production and distribution models tend to emphasise different features depending on whether the model developer has a particular resource or delivery mode in mind and which outcomes they want to examine as an assumption or a model output. This paper develops a general model where both the choice of hydrogen distribution methods and networks are model outputs and tests whether such a model can reproduce some of the characteristics of the results in the literature. We use the State of Victoria in Australia as case study.

The modelling results generally support past conclusions about the relative competitiveness of gas by truck, and liquid by truck and pipeline delivery modes. However, this modelling approach highlights the capacity inflexibility of pipeline hydrogen delivery in response to rising demand. The modelling indicates that pipeline delivery will not be economic during the early stages of market penetration, will reach a point of dominance when demand is significant but at short distance, but may lose significant share of the hydrogen delivery task when new small scale supply fields must be drawn upon as demand expands further.

Keywords: *distribution infrastructure, dynamic optimisation, hydrogen*

1. INTRODUCTION

With the exception of only a few countries, such as Brazil which manufactures large quantities of sugar cane ethanol, oil based fuel products such as petrol and diesel account for the majority of transport fuels consumed. Transport accounts for approximately 14 percent of global greenhouse gas emissions (WRI, 2006) and many countries, particularly in the developed world, are planning to introduce a price on greenhouse gas emissions via either direct taxation or cap and trade schemes. Another important driver in the transport sector is the price of oil. During the 1990s, the price of oil was on average only US$28/bbl. After 2005, the price of oil rose above US$40/bbl and was as high as US$140/bbl in July 2008. It has since dropped back, almost to 1990 levels, due to a substantial reduction in global economic growth taking pressure of the general level of prices across the economy. Despite pressure now being reduced on the oil price, the International Energy Agency (2008) still expects oil prices to average US$100/bbl between 2008 and 2015, with significant volatility around that trend leading to potential for high price spikes, in addition to the current downward trend being experienced. Given the high exposure of most countries to oil as a transport fuel, this presents a significant threat to economic welfare.

The twin pressures of the potential introduction of carbon pricing and higher and more volatile oil prices has revived interest in alternative transport fuels. These include various types of biofuels (e.g. ethanol and biodiesel), natural gas (in compressed or liquefied form), and electricity via battery storage or through fuel cells driven by a fuel source such as hydrogen. Graham et al. (2008) assessed the potential contribution of various alternative fuels in Australia under alternative carbon and oil price scenarios. The study found that the electrification of road transport was a viable and indeed central component of transforming Australia's transport fuel mix. Providing the primary energy source is not greenhouse gas intensive, electrification enables the transport sector to access a lower emission fuel that is also abundant. Most other liquid fuel options do not satisfy these requirements (Figure 1[1]). Only high blends of biodiesel offer significant greenhouse gas reduction, but it is significantly limited in supply. Biodiesel is produced at present from waste cooking oil, tallow or canola, none of which are available in substantial quantities relative to the task at hand. Apart from waste oil, they also have alternative uses which limit the volume available purely for transport needs. Algae based biodiesel may offer greater quantities but is not yet mature (CSIRO and RIRDC, 2007).

It is apparent that electrification is essential for reducing emissions in transport and there are two main approaches. The first is use of on-board batteries to store electricity drawn directly from the grid (assuming electricity is eventually decarbonised). Battery powered electric vehicles are available at around twice the cost of current vehicles, and costs are expected to fall once production volumes increase. Their energy consumption is around 0.2 kWh per kilometre and their range is around 100-150km per day. To travel just 50km a day (closer to the average) requires a night time recharging regime of around 1-2 kWs for 5-10hours.

An alternative path to electrification is use of hydrogen fuel cells. Hydrogen fuel cell vehicles are also currently available. The Honda Clarity is available for lease only and so the vehicle price is unknown (Honda, 2008). The Clarity has a range of 435km holding 5kg of hydrogen at 5000psi in its 171 litre tank.

In comparing these two different paths to the electrification of transport vehicles, the major advantage of hydrogen is that it provides a similar travel range to current vehicles. The major disadvantage is that it lacks fuel distribution infrastructure equivalent to that currently available for liquid hydrocarbon fuel or to the electricity grid if using batteries for storage. This paper focuses on this problem of building distribution infrastructure for hydrogen. Since we already have technologies for converting other energy sources into

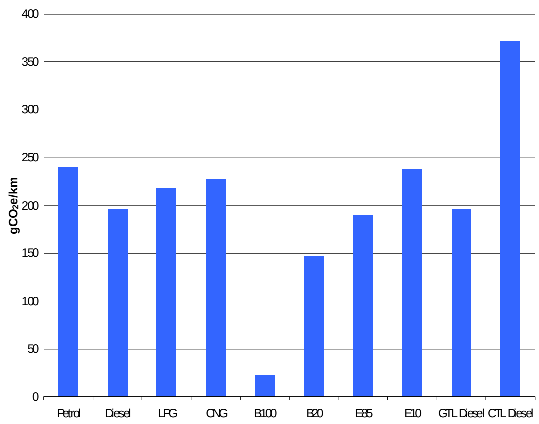

Figure 1. CSIRO estimates of full fuel cycle greenhouse gas emissions of selected transport fuels

[1] LPG is liquefied petroleum gas; CNG is compressed natural gas; B100 is 100 percent biodiesel fuel; B20 is 20 percent biodiesel, 80 percent diesel; E85 is 85 percent ethanol, 15 percent petrol; E10 is 10 percent ethanol 80 percent petrol; GTL is gas to liquids diesel; CTL is coal to liquids diesel.

hydrogen (e.g. electrolysis, gasification and steam reforming) at a cost similar to conventional fuels, and because we also have fuel cell vehicles available in the market (notwithstanding the need to reduce costs), this problem of distribution would seem to be the most pressing issue facing the future of the industry.

A number of studies have contributed to the literature on the distribution of hydrogen fuel. Yang and Ogden (2007) studied the relative merits of three alternative delivery systems: compressed gas carried by truck, liquid gas by truck, and pipelines. Compressed gas trucks were found to be ideal for low consumption markets at a short distance from the hydrogen production site. However if the consumption at the delivery node was high then pipelines were preferred no matter what the delivery distance. If the distance was large but the consumption at the delivery site was moderate then liquid trucks were preferred. Mintz et al (2006) came to similar conclusions. These differences in the optimal distribution infrastructure arise from different combinations of fixed and variable costs for the three distribution technologies that result in economies of scale or distance or both.

Pigneri (2005) studied an additional distribution option, which is to supply electricity to an electrolyser directly at the re-fuelling station, and compared this to compressed gas in trucks and pipelines. He found that there were cost advantages in the strategy of using the electricity grid as the main distribution system, since this avoided building a pipeline that would be under-utilised for many years. However, if the market penetration was above 25 percent, the other distribution options were more cost effective. This follows from the assumption in Pigneri (2005) that smaller scale electrolysers are around twice the cost of the centralised electrolyser plant. In the choice between pipelines and trucks, pipelines were found to be superior because their operating costs were lower and the demand scenarios studied were of high volume supply.

An alternative model described by Parks (2006) considers nine different primary energy resources from which to produce the hydrogen and utilises mathematical programming to solve the network planning problem of determining which distribution paths are used to deliver the hydrogen to the refuelling site. In the Parks (2006) model, the key distribution nodes are refuelling stations within a designated urban area. Each node can on-sell to other nodes. It does not simultaneously solve for multiple cities but can do so iteratively. Only one distribution method may be assumed in each scenario.

From these examples in the literature it is clear that hydrogen production and distribution models tend to emphasise different aspects, depending on whether the model developer has a particular resource or delivery mode in mind and which parameters are to be treated as an assumption or a model output. This paper aims to develop a general model where the choice of both hydrogen delivery modes and of networks are model outputs, and tests whether such a model can reproduce some of the characteristics of the existing results in the literature. Such a model will be cast within a dynamic optimisation framework where the model is provided with the various fixed and variable cost functions of the different distribution paths, and its objective is to solve for the least cost delivery modes to be employed over the whole investment horizon. It must also solve the supply problem of selecting from which fields hydrogen will be manufactured, given both the primary energy resources and the end-users are distributed at varying distances from one another.

In order to populate the model with real world data we chose the State of Victoria in Australia. Distances from resources to major cities vary in that state by between 10 and 250km. Although there are a wide variety of energy sources available in principle, we chose to limit the study to biomass. Biomass is the most geographically distributed resource and therefore provides the most difficult distribution problem. In this case we are using gasification to produce the biomass with the hydrogen produced on site (ruling out the electricity grid as a delivery mode). The model will be generalised to a wider set of primary energy resources in the future. The distribution systems that are included in the study are compressed gas in trucks, liquefied gas in trucks, and pipelines. Although limited by a minimum size threshold, the size of the hydrogen fuel markets vary significantly among several regional capitals and one large capital city in the state. This opens up the possibility that the co-existence of several different distributions options may be the lowest cost.

The following section provides more detail about the model structure. The next section discusses the key assumptions and scenarios applied in the modelling. Following that, we discuss the modelling results and conclusions.

2. MODEL STRUCTURE

The hydrogen fuel distribution model is a dynamic optimisation model which minimises the aggregate cost of meeting a given demand for hydrogen fuel at each demand node, with supply available from various production nodes, or fields, located at different distances. Hydrogen is able to be transported to the demand nodes via three different types of distribution infrastructure which are optimally selected by the model to be least cost over the entire time period of interest.

This type of model structure is a familiar programming problem and so not all of the equations are provided here. However, the key equations, being the objective function, allowable distribution paths and economies of scale in pipeline construction, are discussed.

The objective function is of the following general form:

$$\text{Minimise } \sum_{n,time} \frac{Cost_{n,time}}{(1+r)^{time\text{-}1}} \tag{1}$$

where r is the discount rate and n is the set of costs incurred along the supply chain from the field to the city stations being the costs of:

- production of the biomass feedstock,
- biomass conversion into hydrogen via gasification,
- conditioning the hydrogen ready for transport (relating mainly to the compression or liquefaction of the gas),
- the distribution from field to the city via compressed gas truck, liquefied gas truck, or pipeline: including fixed investments costs associated with the infrastructure such as trucks, trailers and pipelines; and operating costs such as transport energy consumption, capital maintenance and labour,
- intra-city distribution based on an idealised spatial arrangement of refuelling stations in the city as proposed by Yang and Odgen (2007), and
- refuelling infrastructure, which requires different storage and building infrastructure depending on the mode of distribution to the city.

Most of the costs above are described by simple formulations of fixed or linearly increasing costs functions. Costs are typically increasing with distance and the number of units of infrastructure. These are governed by the demand or flow of hydrogen required, and the selection of the least cost supply paths and delivery modes. The main equation governing the selection of least cost supply paths is of the following general form:

$$\sum_{field,mode} Supply_{field,city,mode,time} \geq Demand_{city,time} \tag{2}$$

Under this type of equation, cities cannot trade with one another, but each field may supply more than one city. An equation which indicates the limit of available feedstock at a given field encourages production from several fields. Without this restriction, the solution would simply choose the limitless supply available from the lowest cost field (lowest cost being determined by cost of feedstock, delivery distance and mode).

Whilst we have said that most cost functions are either constant, or linearly increasing with distance and volume, we assume that pipeline delivery experiences economies of scale, that is, decreasing costs with volume of hydrogen transported. In order to represent this we utilise the following equations:

$$\sum_{pipetype} X_{field,city,pipetype,time} \leq 1 \tag{3}$$

$$PipelineCost_{time} = \sum_{field,city,pipetype} X_{field,city,pipetype,time} \times Distance_{field,city} \times \left(CapitalCost_{pipetype} + OMCost_{pipetype}\right) \tag{4}$$

$$PipelineSupply_{field,city,time} \leq X_{field,city,pipetype,time} \times PipeCapacity_{field,city,pipetype} \tag{5}$$

The use of a binary variable X is the primary method for expressing decreasing per unit costs for larger pipelines and controlling the selection of pipeline size. Each step in the cost-quantity function is denoted by an element of the set *pipetype*. Equation (3) ensures that only one or zero steps can be selected. Selection of the point on the stepped cost function is governed by equations (4) and (5). Equation (4) states that pipeline cost is a function of the distance between the hydrogen production field and the end users in the city, and the annual capital and operating costs associated with the selected pipeline size, which is selected through the choice of *X*. Equation (5) states that the pipeline size, *PipeCapacity*, again selected through the choice of binary variable *X*, must be at least as large as the amount to be supplied through it.

3. ASSUMPTIONS

3.1. Data assumptions

The fields are based on Statistical Divisions used by the Australian Bureau of Statistics for collecting data within Australia. Biomass feedstock availability is modelled as a percentage of the three types of feedstock harvested from agricultural land. In this study, we assume only 5 percent of gross feedstock is available for hydrogen production with the remainder of biomass being used primarily for the food market. The total amount of biomass available ranges between 4.8 and 9.9 million dry tones per year. The calorific value of crop and pasture is 8.9 GJ/tFW, and the conversion parameter from wet to dry weight is 1.78tFW/tDM. A fraction of 0.67 is applied to rough biomass resources as a yield adjustment. Therefore, the hydrogen capacities for crop, pasture and rough biomass feedstock are 121.6, 121.6 and 81.5 kgH_2 per dry tonne of feedstock respectively. The cost of the feedstock, shown in Table 1, includes capital costs, operating costs, feedstock cost, and feedstock transportation costs.

There are several potential stages for hydrogen production from biomass. The locations selected for the production facilities can also be optimised. The facilities could be built on the biomass production site, at the city-gate of the demand clusters, or at other intermediate locations. In this case, we assume all hydrogen production facilities are located at the biomass production sites, since in most cases transporting a bulky material such as biomass is not energy efficient. The biomass to hydrogen conversion method is assumed to be a mid-size gasification process with hydrogen output of 24000 kg H_2/day.

Field	Melbourne	Barwon	Western District	Central Highlands	Wimmera	Mallee	Loddon	Goulburn	Ovens-Murray	East Gippsland	Gippsland
$/tDM	37-67	40-67	42-67	41-67	150-251	140-251	60-101	60-101	58-101	38-67	36-67

Table 1: Assumed cost range of biomass feedstock by field, CSIRO unpublished data

Hydrogen is passed to a terminal at the end of the conversion process which prepares the hydrogen for transportation to refuelling stations. The costs of components for the transmission and distribution process are directly obtained or adopted from the values in the "H2A Delivery Components Model" developed by US DOE (2009) Table 2 shows the main assumptions in relation to truck delivery. Pipeline delivery costs per volume of hydrogen are assumed to decrease with pipeline size. The cost of the smallest size pipeline considered is $350,000 per kilometre. The largest is four times the diameter allowing for greater volume but with only a 60 percent increase in costs per kilometre.

Hydrogen distribution within the city is simplified by using the idealised models of the city developed in Yang and Ogden (2007). Based on that approach, the average delivery distances for trucks can be reduced to a simple equation of the radius of the city and the number of stations in the city as follows:

$$Distance = 1.42 \times CityRadius \times Stations\ . \qquad (6)$$

The average intra-city pipeline network length can also be expressed with a simple equation:

$$Distance = 2.43 \times CityRadius \times Stations^{0.4909} \qquad (7)$$

We assume the capital and installation cost for urban pipeline distribution to be $800,000 per km; the fixed operating costs for pipeline are assumed to be 4 percent of total capital cost per annum.

To support the introduction of hydrogen into the light duty vehicle (LDV) markets, hydrogen refuelling stations must be reasonably abundant. Each conventional fuel station today serves an average fleet of 2000

LDVs. Accordingly we assume that the number of hydrogen vehicles served at each station ranges from 200 to up to 2000 hydrogen fuelled vehicles as hydrogen fuel penetration increases into the LDV market. We additionally assume that the number of hydrogen stations must be at least 10 percent of the current number of conventional fuel stations.

At each refuelling station the refuelling infrastructure is assumed to be sized to cope with peak demand achieving an average utilisation factor of 70 percent. The size of the refuelling infrastructure is assumed to increase over time from 150 kg/day to 1,000 kg/day (at each refuelling station) as market penetration increases.

Data	Compressed Gas Trucks (G)	Liquid H2 Trucks (L)
Total Capacity (kg H2)	280	4000
Truck capital Cost:	120,000	120,000
Trailer capital Cost	198,000	750,000
Truck cab lifetime (yr)	10	10
Truck trailer lifetime (yr)	20	20
Load/Unload time (hr)	3	6.5
Fuel Economy of Trucks (L/km)	0.2	0.2
Average speed	65	65
Driver hours	8 hr/driver/day	8 hr/driver/day
Truck Availability	24 hr/day, 3 shifts/day	
Fuel Price ($/L)	1.5	

Table 2: Key assumptions for truck delivery, based on US DOE (2009)

3.2. Scenario design

We examine a single scenario where the consumption of hydrogen for transport in LDVs commences in 2015. It is assumed that there are 0.7 LDVs per person, and fuel consumption for each hydrogen fuelled LDV is 0.6 kg hydrogen per day. Population growth rate is assumed to be a constant 2 percent per annum. Population by region is based on ABS (2006). Market penetration of hydrogen fuel cell vehicles begins at 1 percent, growing to a 20 percent share of the LDV market by the year 2030. This is considered to be a more realistic scenario than those examined in Yang and Odgen (2007) and Pigneri (2005), which examined market penetration rates held constant through time. There are several recent studies that project future market share. Graham et al (2008) found that, under moderate oil and carbon price scenarios, hydrogen fuelled electric vehicles could account for around 25 percent of vehicle-kilometres travelled in Australia in 2050. Under a more stringent carbon constraint, IEA (2008) projected a global fuel cell vehicle uptake share of 40 precent by 2050. The 25 percent share by 2050 projected in Graham et al (2008) was adopted for this paper.

For each demand cluster, hydrogen demand is estimated by the following equation:

$$H_2DemandDensity = PopulationDensity \times VehicleOwnership \times FuelUse \times MarketShare \quad (8)$$

(kg H_2/day/km^2) (people/km^2) (LDV/person) (kg H_2/day/vehicle) (%)

4. MODELLING RESULTS

The key modelling results are presented in Figure 2 and Figure 3. Figure 2 shows the delivery mode that was chosen over time with increasing hydrogen demand. When hydrogen demand is low at the commencement of market uptake in 2015, gas delivery trucks are selected by the model as the least cost mode for hydrogen delivery. After 12 years, the first liquid trucks are utilised and pipeline use commences 5 years later. At this time compressed gas trucks cease to be used as all market are now large enough to justify the larger volume modes of pipeline and liquid truck delivery. Additional pipelines are built in 2038 and over several years from 2045. Each time a new pipeline is built the utilisation of the liquid truck delivery mode decreases but then steadily increases to meet growing demand.

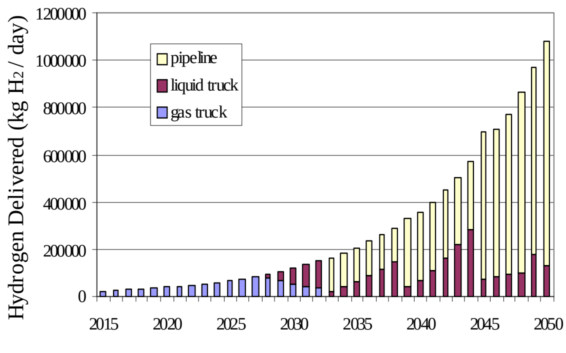

Figure 2: Hydrogen fuel consumption by delivery mode

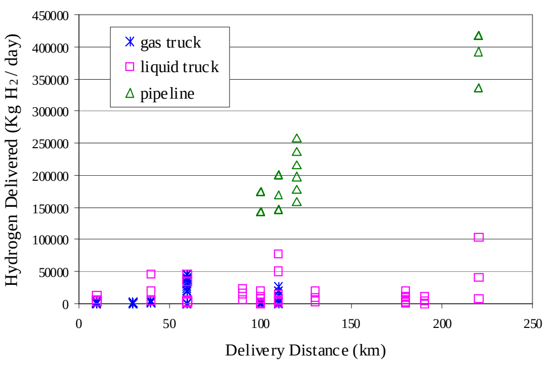

Figure 3: Hydrogen consumption by distance travelled and delivery mode during the projection period

The shift to liquid gas delivery over the longer term reflects the fact that, as demand increases, biomass resources nearer to the demand clusters are reaching their maximum supply levels and hydrogen delivery distances are increasing. While compressed gas delivery is the most cost effective over shorter distances and smaller volumes, liquid delivery becomes more competitive for smaller volumes over longer distances (Figure 3). Pipelines are best suited to large volumes over a wide range of distances but their routes and capacities are inflexible. Pipelines lose market share to trucks delivering compressed gas, when demand is initially low, and liquefied gas when delivery distances are long but volumes are not yet high enough to justify a new pipeline.

5. DISCUSSION AND CONCLUSIONS

The results build on the existing literature on hydrogen distribution modelling by presenting a model that jointly optimises the selection of both the least cost supply network and the delivery mode. The scenario framework is also altered towards the more realistic case where demand begins low and grows over several decades to supply a significant market share (assuming fuel cell vehicles can be cost competitively produced) whereas previous literature has tended to explore scenarios where market share is fixed over time. The modelling results generally support past conclusions about the relative competitiveness of gas in truck, liquid in truck and pipeline delivery modes. However, the modelling approach here highlights the inflexibility of pipeline hydrogen delivery capacity in response to rising demand. The modelling indicates that pipeline delivery will not be economic during the early stages of market penetration, will reach a point of dominance when demand is significant and at a short distance, but may lose significant share of the hydrogen delivery task when new, small scale, supply fields must be drawn upon as demand expands further.

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