Analysis of Hydrogen Economy for Hydrogen Fuel Cell Vehicles in Ontario

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Abstract

The ‘Hydrogen Economy’ is a proposed system where hydrogen is produced from carbon dioxide free energy sources and is used as an alternative transportation fuel. Application of hydrogen on-board fuel cell vehicles (FCVs) can significantly decrease harmful air pollutants and greenhouse gases emissions. There must be significant transition of infrastructure in order to achieve the hydrogen economy with investment required in both production and distribution infrastructure. This research is focused on the projected demands for infrastructure transition of hydrogen economy in Ontario, Canada. Three potential hydrogen demand and distribution system development scenarios are examined to estimate hydrogen FCVs market penetration, as well as the associated hydrogen production and distribution. Demand of transportation hydrogen is estimated based on various types of hydrogen FCVs. Finally, an estimate of hydrogen demand from FCVs in Ontario and the resulting cost of delivered hydrogen are investigated.

Keywords
Hydrogen economy, hydrogen fuel cell vehicles, Hydrogen demand scenarios, Ontario

1. Introduction

There is an increasing need for alternative fuels to meet the increasing global energy demand, current urban air quality impacts and the treaty of global climate change (Lin et al. 2008). According to Statistics Canada (2007), energy demand in Canada has increased from 7385 petajoules in 2003 to 7643 petajoules in 2006. The global energy demand is projected to increase by over 60% by 2030 (Kamarudin et al. 2009). About 18% of energy is consumed by the transportation sector, and the transportation sector also accounts for 20% of the projected energy demand increment until 2030 (Ball et al. 2008). Automobile fuel combustion also emits enormous amount of air pollutants. According to Environmental Protection Agency of US (2008), in 2007 approximately 75% of CO emissions were contributed by highway vehicles and non-road mobile sources and nearly 50% of VOC emission came from highway vehicles. These air pollutants deteriorate urban air quality and also threaten human health. Scientific studies show that air pollutants can cause some health problems such as aggravation of respirator, cardiovascular diseases, and cancers (OMA 2005). For instance, in the state of Ontario over 1700 deaths a year are thought to be a result of poor urban air quality (OMA 2005). In addition, Greenhouse Gas emissions from automobiles contribute significantly to the global warming (Dougherty et al. 2008).

To overcome the above mentioned issues, hydrogen is envisioned as a clean energy carrier which can replace fossil oil. Hydrogen can also be used as an energy storage medium that facilitates the implementation of intermittent renewable power sources such as wind and solar (Taljan et al. 2008). The emerging technology of on-board hydrogen fuel cells are near commercialization. Moreover, the overall energy efficiency of hydrogen FCVs is also higher than internal combustion vehicles (ICE) vehicles (Campanari et al. 2008). The main automakers have already started their FCVs projects and developed a few fuel cell models, such as Hydrogen3 in 2002 from GM, Focus FCV from Ford, FCHV-5 in 2001 from Toyota, and FCX model in 1999 from Honda (DOE 2004). With the current advancement in fuel cell technology, hydrogen FCVs are moving towards market penetration. In this paper, three scenarios were built to describe and explore the growth trend of fuel cell vehicle market, hydrogen demand from FCVs and the resulting cost of hydrogen production.
2. Hydrogen Demand from H2 FCVs in Ontario

2.1 Number of FCVs in Ontario Market

Based on the demand scenarios obtained from Greene et al. (2007), this paper assumes that the growth of hydrogen FCVs in Ontario will follow a similar trend in the near future. With this assumption, three scenarios were built to describe the growth of the FCVs market from 2015 to 2050, as exhibited in Table 1.

<table>
<thead>
<tr>
<th>Year</th>
<th>2015</th>
<th>2025</th>
<th>2050</th>
</tr>
</thead>
<tbody>
<tr>
<td>Market share (Scenario 1)</td>
<td>0.00</td>
<td>0.04</td>
<td>0.91</td>
</tr>
<tr>
<td>Market share (Scenario 2)</td>
<td>0.00</td>
<td>0.05</td>
<td>0.95</td>
</tr>
<tr>
<td>Market share (Scenario 3)</td>
<td>0.00</td>
<td>0.15</td>
<td>0.95</td>
</tr>
</tbody>
</table>

The year of 2015 is considered as the time when hydrogen FCVs enter automobile market, and the year of 2025 is the time when hydrogen FCVs start growing rapidly. While the year of 2050 is assumed to be the time when hydrogen FCVs dominate car market and essentially all FCVs are fuelled by hydrogen. Scenario 1, 2 and 3 represent conservative, moderate and optimistic hydrogen fuel cell vehicle market development expectations, respectively. Based on hydrogen FCVs market development assumptions above, the next section presents the logistic model which will be used to estimate hydrogen demand in order to service these vehicles.

2.2 Logistic Model

The work of Collantes (2007) outlined that the logistic model could be applied to describe hydrogen FCVs market development. The logistic model is defined as follows:

$$ P_{FCV} = \frac{1}{1 + \exp\left[-\left(a_{FCV} + b_{FCV} (t - t_0)\right)\right]} $$

where $P_{FCV}$ is the car sale market share of hydrogen FCVs, $a_{FCV}$ and $b_{FCV}$ are the coefficients of the logistic model, $t_0$ is the year of hydrogen FCVs entering car sale market, which is assumed to be 2015 for Ontario, and $t$ is the time (year).

Using the values in Table 1 and the logistic model, the hydrogen FCVs market share in each year over a long-term planning horizon is shown in Fig. 1.

![Figure 1: Hydrogen FCVs sale market share](image)

2.3 Number of Annual Hydrogen FCVs Sale

The number of hydrogen FCVs annual sale in Ontario is estimated as follows:

$$ N_{FCV} = P_{FCV} \times N_{new\ car\ sale} $$

where $N_{FCV}$ is the number of new hydrogen FCVs sold in each year, $P_{FCV}$ is percentage of hydrogen FCVs on annual new car market, and $N_{new\ car\ sale}$ is the number of new vehicles sold in each year.
The value of \( N_{\text{new car sale}} \) is estimated using historical data of the number of new vehicle sale in Ontario from 1968–2007 (Statistics Canada 2008). Through a linear regression on the historical data, a pattern for the number of new vehicle sold in Ontario each year is estimated as below.

\[
N_{\text{new car sale}} = -1.211 \times 10^7 + 6353t
\]  

(3)

2.4 Estimation of Accumulative Number of Hydrogen FCVs

The total number of fuel cell vehicles can be estimated by the following equation

\[
N_i = N_{\text{accumulation}} - N_{\text{unused car}}
\]  

(4)

where \( N_{\text{accumulation}} \) is the accumulated number of hydrogen FCVs sold from the 1st year to the year \( i \) (i.e. 2015–2050), \( N_{\text{unused car}} \) is the number of hydrogen fuel cell vehicles which will be out of the road in the year \( i \), and \( N_i \) is the total number of hydrogen fuel cell vehicles running on road in the year \( i \).

Assume \( N_{\text{unused car}} \) is the number of hydrogen FCVs which are out of vehicle lifetime (\( N_{\text{out of vehicle lifetime}} \)), Eq. 4 is transformed as follows:

\[
N_i = N_{\text{accumulation}} - N_{\text{out of vehicle lifetime}}
\]  

(5)

\( N_{\text{out of vehicle lifetime}} \) is estimated to be the cumulative number of hydrogen FCVs sold from the 1st year to the year of “\( i \)-lifetime”. For example, if vehicle lifetime is 10 years, and then \( N_{\text{out of vehicle lifetime}} \) will be the cumulative number of hydrogen FCVs sold from the 1st year to \( i \)-10th year. The next section presents how to estimate the lifetime of hydrogen FCVs.

2.5 Vehicle Lifetime

The lifetime hydrogen FCVs can be estimated by the following equation:

\[
LT = LM / D
\]  

(6)

where \( LT \) is lifetime of one vehicle in Ontario, \( LM \) is the lifetime mileage of one passenger car in Ontario, and \( D \) is the annual travel distance per vehicle in Ontario.

The lifetime mileage (\( LM \)) of a passenger car was estimated to be 152,137 miles (Lu 2006). A survey of Statistics Canada (2006) showed that total travel distance (\( D_{\text{total}} \)) of all vehicles in Ontario in 2005 was estimated to be 125,102 million kilometres; while in 2005 the number of registered vehicles (\( N_{\text{registered vehicles}} \)) in Ontario was 7,130,323. Substituting these two numbers into Eq. 7 shown below, the annual travel distance per vehicle (\( D \)) can be found.

\[
D = D_{\text{total}} / N_{\text{registered vehicles}}
\]  

(7)

Based on the above discussions and using Eqs. 2 and 4–6, the estimated number of on-road hydrogen FCVs in Ontario from 2015 to 2050 is displayed in Table 3. It must be noted that this is a conservative estimate (i.e. assuming that FCV will last the same as the current ICE vehicles), but it is anticipated with improving technology that the durability of fuel cell vehicles will increase over time.

<table>
<thead>
<tr>
<th>Year</th>
<th>2015</th>
<th>2020</th>
<th>2025</th>
<th>2030</th>
<th>2035</th>
<th>2040</th>
<th>2045</th>
<th>2050</th>
</tr>
</thead>
<tbody>
<tr>
<td>Scenario 1</td>
<td>0</td>
<td>32,336</td>
<td>132,070</td>
<td>423,990</td>
<td>1,179,800</td>
<td>2,816,700</td>
<td>5,410,800</td>
<td>8,347,700</td>
</tr>
<tr>
<td>Scenario 2</td>
<td>0</td>
<td>36,941</td>
<td>159,530</td>
<td>540,370</td>
<td>1,546,200</td>
<td>3,602,700</td>
<td>6,514,900</td>
<td>9,404,000</td>
</tr>
<tr>
<td>Scenario 3</td>
<td>0</td>
<td>152,760</td>
<td>543,690</td>
<td>1,432,700</td>
<td>3,032,500</td>
<td>5,383,400</td>
<td>7,988,200</td>
<td>10,202,000</td>
</tr>
</tbody>
</table>

2.6 Hydrogen Consumption of Hydrogen FCV

Currently, there is still no fully commercial hydrogen FCV in the market yet, but relatively successful FCV demonstration models can be taken as a reference case, such as GM Equinox Fuel Cell Vehicle, which has been tested on a 100-fleet scale. The fuel storage pressure and capacity as well as the operating range of this model are 700 bars, 4.2 kg, and 320 km, respectively (GM 2009). The model is considered as a light sport utility vehicle; thus it represents a worst case high hydrogen vehicle demand.
This study regards GM Equinox as the standard fuel cell vehicle and assumes fuel efficiency of Equinox will be the average fuel consumption of hydrogen FCVs. Thus, the hydrogen consumption per hydrogen FCV will be estimated as follows:

\[ H_{FCVs} = \frac{\text{Hydrogen storage}}{\text{Operating range}} \] (8)

Therefore, total hydrogen demand per hydrogen FCV in a year can be estimated as follows:

\[ H_{Y FCVs} = H_{FCVs} \times D \] (9)

2.7 Overall Hydrogen Demand Estimation

Upon the estimation of hydrogen FCVs market development, we will evaluate the hydrogen demand from hydrogen FCVs. Firstly, we will consider hydrogen consumption from one hydrogen fuel cell vehicle, and then hydrogen demand from all vehicles can be derived accordingly. It should be noted that this analysis can be easily extended and adapted to accommodate, plug in hybrid electric vehicles (PHEVs). Early market PHEVs are expected to have gasoline ICE or diesel range extenders. Over time (e.g. assuming in this model starting at 2015) the range extender power source in these vehicles will be substituted with hydrogen fuel cells. This model will be of good utility through assuming PHEV fully commercialized, and simply there will be less demand from each PHEV vehicle, as a limited amount of travel mileage will be achieved with the battery under charge depleting mode.

The total hydrogen demand from all hydrogen FCVs in Ontario is estimated by multiplying \( H_{Y FCVs} \) by the total number of vehicles running on the road for a specific year, as shown in Eq. 10. The obtained results are summarized in Table 4.

\[ H_{T FCVs} = H_{Y FCVs} \times N_i \] (10)

Table 3: Hydrogen demand of hydrogen FCVs in Ontario from 2015 to 2050 (kg/yr)

<table>
<thead>
<tr>
<th>Year</th>
<th>2015</th>
<th>2020</th>
<th>2025</th>
<th>2030</th>
<th>2035</th>
<th>2040</th>
<th>2045</th>
<th>2050</th>
</tr>
</thead>
<tbody>
<tr>
<td>Scenario 1</td>
<td>0</td>
<td>7.45E+06</td>
<td>3.04E+07</td>
<td>9.76E+07</td>
<td>2.72E+08</td>
<td>6.49E+08</td>
<td>1.25E+09</td>
<td>1.92E+09</td>
</tr>
<tr>
<td>Scenario 2</td>
<td>0</td>
<td>8.51E+06</td>
<td>3.67E+07</td>
<td>1.24E+08</td>
<td>3.56E+08</td>
<td>8.30E+08</td>
<td>1.50E+09</td>
<td>2.17E+09</td>
</tr>
<tr>
<td>Scenario 3</td>
<td>0</td>
<td>3.52E+07</td>
<td>1.25E+08</td>
<td>3.30E+08</td>
<td>6.98E+08</td>
<td>1.24E+09</td>
<td>1.84E+09</td>
<td>2.35E+09</td>
</tr>
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</table>

3. Hydrogen Cost

In this section, economic estimates for hydrogen production, storage and distribution are conducted to investigate hydrogen cost based on the estimated hydrogen demand of hydrogen FCVs in Ontario. There are a number of methods ways to produce hydrogen such as steam reforming of methane (SMR), water electrolysis, high temperature electrolysis, and thermochemical cycle hydrogen production (Chui et al. 2006). The selection of hydrogen production technology and distribution method is specific to each region, with regional limitations and energy generation capacity considered (Lin et al. 2008). In Ontario, for example, there is a policy decision to eliminate energy production from coal in order to address climate change concerns, and thus hydrogen form coal is not assumed in this work, but others have considered coal (Nils et al. 2008 and Strachan et al. 2009).

Approximately 50% of power in Ontario is generated from nuclear and 25% from renewable energy resources with specific goals to increase renewable energy generation. Steam reforming of methane is the most common process to produce hydrogen in large scale production, but it is not taken into account in this paper, due to a large amount of carbon dioxide being generated as by-product. Also in the future there are expected increases in natural gas price that will make SMR less competitive. Theoretically, high temperature electrolysis and thermochemical cycle do not produce any pollutant or greenhouse gas directly. The efficiencies of high temperature electrolysis and thermochemical cycles are projected to reach up to 53% and 45%, respectively (Fujiiwara et al. 2008 and Elder et al. 2009). However, these two methods are still at the phase of research, not fully applicable at this time. Therefore, this paper uses centralized water electrolysis is regarded as a “green” option to be selected to generate hydrogen. During the transition to hydrogen economy, distributed hydrogen production by via on-site electrolyser is likely to be utilized to meet the demand rather than centralized production (US NRC 2004). Figure 2 demonstrates the flow chart of centralized hydrogen production and distribution analysis for hydrogen FCVs in Ontario.
### 3.1  Cost of Water Electrolysis Hydrogen Production

The cost of hydrogen produced via water electrolysis consists of two parts: operating cost and depreciable capital investment. Operating cost includes cost of water, electricity, labor and labor related costs, while depreciable capital investment includes purchased equipment, piping, electrical, instrumentation and other auxiliary costs. For the sake of brevity, interested readers can refer to the work of Ivy (2004), Environment Canada (2008), Weinert (2005), and Garrett (1989) for the parameters that were assumed in obtaining the total cost of water electrolysis hydrogen production. Since this paper considers centralized hydrogen production, it is assumed that the hydrogen production will be co-located (or very close) with primary energy production; thus there is no electricity transmission cost added. The following subsections discuss the main cost components that constitute the total cost of water electrolysis hydrogen production.

#### 3.1.1 Cost of Water Consumption

Water consumption can be estimated by the equation below,

\[
W_{\text{consumption}} = \frac{F_{\text{hydrogen}} \times M_{\text{water}}}{M_{\text{hydrogen}} \times E_{\text{conversion}}}
\]  

(11)

where \( W_{\text{consumption}} \) is water consumption by water electrolysis (kg H\(_2\)O/h), \( F_{\text{hydrogen}} \) is flow rate of hydrogen output (kg H\(_2\)/h), \( M_{\text{water}} \) is molecular weight of water (g H\(_2\)O/mol), \( M_{\text{hydrogen}} \) is molecular weight of hydrogen (g H\(_2\)/mol), and \( E_{\text{conversion}} \) is conversion efficiency of water to hydrogen (%).

#### 3.1.2 Cost of Electricity Consumption

Consumption of electricity is defined as follows:

\[
E_{\text{consumption}} = \frac{H_{\text{heating value}} \times F_{\text{hydrogen}}}{E_{\text{energy}}}
\]  

(12)

where \( E_{\text{consumption}} \) is electricity consumption of water electrolysis (kWh/h), \( H_{\text{heating value}} \) is high heating value of hydrogen (kWh/kg H\(_2\)), and \( E_{\text{energy}} \) is energy efficiency of water electrolysis (%).

#### 3.1.3 Labor Cost

Assuming 4 operators per shift, the total cost of labor can be calculated as follows:

\[
L_{\text{cost}} = \frac{N_{\text{operator}} \times S_{\text{operator}}}{F_{\text{hydrogen}}}
\]  

(13)

where \( L_{\text{cost}} \) is cost of labor ($/kg H\(_2\)), \( N_{\text{operator}} \) is the number of operators at a shift, and \( S_{\text{operator}} \) is hourly salary of operators ($/h-operator).

#### 3.1.4 Depreciable Capital Investment

The cost of electrolyzer hydrogen generation station unit is given by Weinert (2005). However considering a large number of units required by the centralized hydrogen production station, an electrolyzer unit price would decrease to
some level. Progress ratio equations (Seebregts et al. 1999) are introduced to account for the decrease in the price, as defined below.

\[ SC = SC_0 \left( \frac{C}{C_0} \right)^{-b} \]  \hspace{1cm} (14)

\[ Pr = 2^{-b} \]  \hspace{1cm} (15)

where \( SC \) is unit cost with cumulative capacity \( C \), \( C_0 \) is cumulative capacity, \( b \) is learning index, \( C_0 \) is initial cumulative capacity, \( SC_0 \) is initial unit cost with initial cumulative capacity, and \( Pr \) is progress ratio.

Cumulative capacity is defined as the total number of electrolyzer hydrogen generation station, while initial cumulative capacity \( C_0 \) is 1. Cost of electrolyzer generation station \( SC_0 \) and value of progress ratio \( Pr \) can be found in (Weinert 2005) and then we can achieve the unit cost \( SC \) and the total cost of electrolyzer hydrogen generation stations.

The total cost of plant is estimated by the factor method, which assumes that the cost of other part of plant to be fractions of purchased equipment cost. Thus, the total cost of plant will be the multiplication of the sum of factors and the cost of purchased equipment. The values of factors can be found in (Garrett 1989). The depreciation of total plant cost was calculated using the straight line method (Turton et al. 2007), which defined as:

\[ Depreciation = (Original \ plant \ cost - Salvage \ value) / plant \ life \ time \]  \hspace{1cm} (16)

where the values of salvage and plant lifetime were assumed to be zero and 30 years, respectively.

### 3.1.5 Cost of Electrolysis Hydrogen Generation

Upon estimation results obtained above, the cost of electrolysis hydrogen generation is estimated by the equation below.

\[ TCP = CP_{electricity} + CP_{water} + CP_{labor} + CP_{depreciation} \]  \hspace{1cm} (17)

where \( TCP \) is the total cost of electrolysis hydrogen generation ($/kg H_2), \( CP_{electricity} \) is unit cost of electricity consumption of electrolysis ($/kg H_2), \( CP_{water} \) is unit cost of water consumption of electrolysis ($/kg H_2), \( CP_{labor} \) is unit cost of labor ($/kg H_2), and \( CP_{depreciation} \) is the unit depreciation from capital investment ($/kg H_2).

### 3.2 Cost of Gaseous Hydrogen Storage and Distribution

The parameters and equations used to estimate the capital and operating costs of compressed gaseous hydrogen storage and pipeline distribution can be found in (Garrett 1989 and Amos 1998).

#### 3.2.1 Gaseous Hydrogen Storage

Since hydrogen is a very light element compared with other gases, the density of hydrogen gas is low; therefore compressing hydrogen gas prior to storage is considered to be an economical way to store hydrogen. The process of hydrogen gas storage requires high pressure compressors and storage tanks, thus the cost of hydrogen storage will include operating cost of hydrogen compression and capital investment depreciation of compression and storage equipment.

The power consumption of high pressure hydrogen compressors in kWh/h is:

\[ E_{\text{comp}} = \text{Flow} \times \text{ComPower} \left[ \ln \left( \frac{P}{P_0} \right) \right] \]  \hspace{1cm} (18)

where \( Flow \) is the flow rate of hydrogen gas, \( ComPower \) is the power consumption of hydrogen compressor at the reference pressure, \( P_0 \) is atmospheric pressure, \( P_1 \) is the reference pressure, and \( P \) is the operating pressure of compressors used in the plant.

The cooling water consumption of high pressure hydrogen compressors in gallon/h is:
where $\text{CompCool}$ is the reference value of cooling water consumption.

The capital cost of high pressure hydrogen compressor is:

$$\text{CompCap} = \text{CompCost} \times \text{CompSize} \left( \frac{E_{\text{comp}}}{\text{CompSize}} \right)^{\text{CompExp}} \left( \frac{P}{P_1} \right)^{\text{CpExp}}$$

(20)

where $\text{CompCost}$ is the reference cost of hydrogen compressor per unit power consumption, $\text{CompSize}$ is the reference compressor power, $\text{CompExp}$ is the assumed exponent of compressor size, and $\text{CpExp}$ is the assumed exponent of compressor pressure.

The capital cost of the hydrogen storage tank is:

$$\text{TankCap} = \text{TankCost} \times \text{TankSize} \left( \frac{\text{Storage}}{\text{TankSize}} \right)^{\text{TankExp}} \left( \frac{P}{\text{TankPress}} \right)^{\text{TPExp}}$$

(21)

where $\text{TankCost}$ is the reference cost of hydrogen gas tank per unit gas volume, $\text{TankSize}$ is the reference volume of hydrogen gas tank, $\text{Storage}$ is the design volume of hydrogen gas tank at the pressure $P$, $\text{TankPress}$ is the reference pressure of gas tank, $\text{TankExp}$ is the exponent of tank size, and $\text{TPExp}$ is the exponent of gas tank pressure.

The operating costs of hydrogen compression and cooling are calculated by Eqs. 18 and 19, respectively. Since storage tank farm is usually integrated with production site, both production and storage are always operated together, the cost of storage labours and the related costs will not be counted separately in this analysis.

The high pressure hydrogen compressors and gas tanks are the main equipment for hydrogen gas storage. Costs of compressors and compressed gas tank are estimated by Eqs. 20 and 21, respectively. The total cost of gaseous storage tank farm is estimated by the factor method, and compressors and storage tanks are regarded as the main purchased equipment. The value of purchased equipment factor is considered to be 1.00, while the values of other factors are assumed to be a fraction of the main equipment as stated in the work of (Garrett 1989 and Amos 1998). Depreciation is calculated by straight line method.

Finally, the total cost of gaseous hydrogen storage is computed as follows:

$$\text{TCS} = \text{CS}_{\text{electricity}} + \text{CS}_{\text{cooling water}} + \text{CS}_{\text{depreciation}}$$

(22)

where $\text{TCS}$ is the total cost of gaseous hydrogen storage ($/\text{kg } \text{H}_2$), $\text{CS}_{\text{electricity}}$ is unit cost of energy consumption from compression ($$/\text{kg } \text{H}_2$), $\text{CS}_{\text{cooling water}}$ is unit cost of cooling water consumption from compression ($$/\text{kg } \text{H}_2$), and $\text{CS}_{\text{depreciation}}$ is unit depreciable hydrogen gas storage capital investment ($$/\text{kg } \text{H}_2$).

### 3.2.2 Hydrogen Gas Pipeline Distribution

Capital investment of hydrogen gas pipeline is estimated using Eq. 20 (Parker 2004). The length of the pipeline is assumed to be 200 km.

$$\text{Pipeline Cost} = \left[ 924.5 \ D^2 + 12040 \ D + 260280 \right] L + 378750$$

(23)

where $D$ is the diameter of hydrogen gas pipeline (inch), and $L$ is distance (mile).

### 3.3 Cost of Liquid Hydrogen Storage and Transportation

The parameters and equations used to estimate the capital and operating costs of liquid hydrogen storage and truck transportation can be found in (Garrett 1989 and Amos 1998).
3.3.1 Liquid Hydrogen Storage
The most feasible alternative to compressed hydrogen storage is liquefied hydrogen. Liquefiers and cryogenic storage tanks are required in hydrogen liquefaction process. Consequently, cost of liquid hydrogen storage is considered to be the sum of operating cost of liquefaction process, storage and depreciation of capital investment. Operating cost consists of power consumption, cooling water consumption, and labor cost. As mentioned earlier, labor cost is not taken into consideration for the estimation of liquid storage cost. Power and cooling water consumption are evaluated using Eqs. 24 and 25, respectively. Cost of liquefiers and cryogenic storage tanks are the main part of capital investments (see Eqs 26 and 27), while costs of other parts are assessed by factor method.

The power consumption of hydrogen liquefiers in kWh/h is computed as follows:

$$LiqEnergy = Flow \times LiqPower$$

where $LiqPower$ is the power consumption of liquefier per unit mass of liquid hydrogen.

The cooling water consumption of hydrogen liquefiers in gallon/h is:

$$Cooling = Flow \times LiqCool$$

where $LiqCool$ is the cooling water consumption per unit mass of liquid hydrogen.

The capital cost of liquefiers is:

$$LiqExp = LiqCost \times LiqSize \left( \frac{Flow}{LiqSize} \right)^{LiqExp}$$

where $LiqCost$ is the cost of liquefier per unit mass of liquid hydrogen, $LiqSize$ is the reference production capacity of liquefier, and $LiqExp$ is the exponent of liquefier size.

The capital cost of liquid hydrogen storage tank is:

$$StorageExp = StorageCost \times StorageSize \left( \frac{Storage}{StorageSize} \right)^{StorageExp}$$

where $StorageCost$ is the cost of liquefier per unit mass of liquid hydrogen, $StorageSize$ is the reference production capacity of liquefier, and $StorageExp$ is the exponent of liquefier size.

3.3.2 Cost of Cryogenic Truck Transportation
Cost of cryogenic truck transportation is considered to consist of truck fuel cost, labor cost and cost of cryogenic trucks. These three cost components can be estimated by Eqs. 28–30. The parameters in these equations can be found in (Garrett 1989 and Amos 1998).

$$TruckCap = TruckNumber \times (CabPrice + TrailerPrice + UnderPrice)$$

$$LaborCosts = TranspHours \times DriverWage$$

$$FuelCost = DieselOilPrice \times TruckMileage$$

3.4 Cost of Hydrogen
Combining all cost elements discussed in Section 3, the total cost of liquid and gaseous hydrogen from production, storage and distribution were estimated. Tables 4 and 5 illustrate the hydrogen demand, cost of liquid and gaseous hydrogen, respectively. The costs of hydrogen for the three scenarios are different from each other due to the difference in the estimated hydrogen demand from the scenarios. As shown in results, larger scale production can generate lower unit cost of product. However, the results also show that when production scale is increased up to certain level, the impact of production scale will become minimal, and the costs of hydrogen of the three scenarios turn to be almost identical.
The model also shows that in the early year, when hydrogen production scale is small, costs of gaseous hydrogen storage and distribution are higher than liquid hydrogen storage and transportation. It is because gaseous hydrogen storage and distribution need a larger amount of capital investment on high pressure gas compressors, storage tanks and pipeline, compared with relative low investment on liquid tank farm and cryogenic trucks. However, when production capacity starts increasing, unit cost of gaseous hydrogen storage and distribution will become lower than liquid hydrogen. Figure 3 shows the trend of storage and distribution cost of hydrogen gas and liquid in accordance with hydrogen economy development.

### Figure 3: Cost of hydrogen storage and distribution (scenario 1)

4. **Conclusions**

Upon market expectations, this paper uses logistic models to represent fuel cell vehicle market penetration in Ontario. Three scenarios were established to demonstrate the optimistic, moderate and conservative FCVs market development, respectively. The number of FCVs and the corresponding hydrogen demand were estimated by the presented model. Based on demand estimation, costs of centralized water electrolysis hydrogen production, hydrogen storage and distribution were investigated. The analysis concludes that for the conservative case (scenario 1):
• The cost of hydrogen via compressed gas pipeline to the Greater Toronto Area (GTA) is 3.19 $/kg in 2050, while the cost of hydrogen via cryogenic truck transportation is 3.68 $/kg.

• The total amount of hydrogen production demand from the fleet of light duty hydrogen vehicles is about $1.92\times10^{9}$ kg/year in 2050. Assuming that hydrogen production is wholly from water electrolysis and production capacity matches hydrogen demand exactly, the power consumption from hydrogen production will be about 12,140 MW and 13,900 MW for gaseous and liquefied hydrogen respectively, which are about 36% and 41% of the current Ontario’s installed power generation capacity, 33770 MW (OPA 2007).

• In 2025, the cost of hydrogen starts to level off at 3.81 $/kg and 4.35 $/kg for gaseous and liquefied hydrogen, respectively. This is the time when large scale centralized hydrogen project would be mostly required.

The analysis also shows that production scale and cost of power have significant influence on cost of hydrogen. Also the study shows that pipeline distribution from centralized facilities is preferable for large scale hydrogen production, while cryogenic truck transportation is suitable for small scale production. The paper could be improved by conducting a sensitivity analysis in order to investigate the impacts of model parameters, such as electricity and water prices, energy efficiency of water electrolysis, and plant life, on the design of the future hydrogen infrastructure in Ontario’s FCV market. In addition, the proposed model could be further improved by evaluating the environmental impact in terms of pollutants and greenhouse emissions analyzing the entire hydrogen supply chain, starting with the generation of electricity and ending up with the hydrogen dispensing technology.

References


