NUCLEAR-PRODUCED HYDROGEN BY A THERMOCHEMICAL CU-CL PLANT FOR PASSENGER HYDROGEN TRAINS

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Abstract

This paper compares the technical and economic aspects of electrification of a passenger-train operation in Ontario Canada, versus operation with hydrogen trains using nuclear-produced hydrogen. A local GO Transit diesel operation in Ontario has considered electrification as an alternative to reduce greenhouse gas emissions of passenger trains in the Toronto area. Hydrogen production from nuclear energy via a thermo-chemical Copper-Chlorine (Cu-Cl) cycle for train operation is shown to have lower emissions than direct electrification. It significantly reduces the greenhouse gas emissions compared to diesel operation. A bench-mark reference case used for the nuclear thermo-chemical Cu-Cl cycle is the Sulfur-Iodine (S-I) cycle, under investigation in the USA, Japan, and France, among others. The comparative study in this paper considers a base case of diesel operated passenger trains, within the context of a benefits case analysis for train electrification, for GO Transit operations in Toronto, and the impact of each cost component is discussed. The cost analysis includes projected prices of fuel cell trains, with reference to studies performed by train operators.

1. Introduction

Hydrogen generated from non-polluting sources is a promising solution to the problem of energy demand vs. environmental degradation that the world is facing today. Thermal energy taken from heat rejected from nuclear plants, industrial processes, or collected from solar energy, can be used to produce hydrogen without further conversion into electricity, as in the case with electrolysis. At standard conditions of 25 ^{o}C and atmospheric pressure, the minimum energy required for separating water into hydrogen and oxygen is 286 kJ/mol. This represents the

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enthalpy of formation of water. However, since water does not separate directly into its components, and other intermediate steps are necessary, the total energy required depends on the process and not solely the thermodynamic state of water [1]. The thermo-chemical Cu-Cl cycle for hydrogen generation uses "waste heat" and operates at much lower temperatures than other thermo-chemical cycles, so it is potentially less stringent with regards to materials and maintenance requirements.

#	Reaction	Temperature °C	Type
1	2Cu(s) þ 2HCl(g) → 2CuCl(l) + H2(g)	430–475	Endothermic
2	2CuCl(s)+2CuCl (aq) → CuCl2(aq) + Cu(s)	< 100	Electrochemical
3	CuCl2(aq) → CuCl2(s)	<100	Endothermic
4	2CuCl2(s) + H2O(g) → CuO.CuCl2(s) + 2HCl(g)	400	Endothermic
5	CuO$CuCl2(s)→ 2CuCl(l) + 1/2O2(g)	500	Endothermic

Table 1: Reactions in the Thermo-chemical Cu-Cl Process [2]

The five steps occur in a continuous loop (See Fig 1) where water enters at 25 °C and heat is supplied at 500 °C. The past literature indicates that for each gram of hydrogen produced, the thermo-chemical process requires 221 kJ of heat for endothermic reactions and ancillary heating processes [2]. **Error! Reference source not found.** shows the approximate temperatures at which each reaction occurs, where reactions 1, 3, 4, 5 are thermally driven and reaction 2 is electrochemically driven.

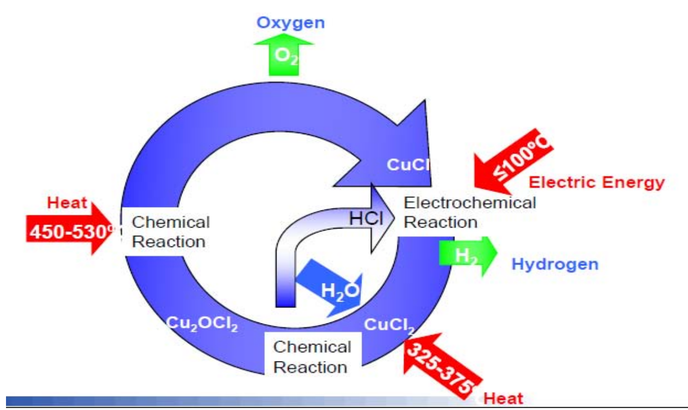

Figure 1: Thermo-chemical process for the generation of hydrogen (4)[4]

2. Thermo-chemical Cu-Cl hydrogen production from nuclear energy

The Generation IV International Forum selected in 2002 six concepts of Super Critical Water Cooled Reactors for deployment by 2030. Most of the six systems employ a closed fuel cycle to maximize the resource base and minimize high-level waste sent to a repository. Only one is cooled by light water, two are helium-cooled and the others have lead-bismuth, sodium or fluoride salt coolant. The latter three operate at low pressure, with a resulting safety advantage. The last has the uranium fuel dissolved in the circulating coolant. Temperatures range from 510°C to 1,000°C, compared with less than 330°C for today's light water reactors. This means that four of them can be used for thermo-chemical hydrogen production. The CANDU supercritical water reactor (25 MPa and 510 - 625°C) directly drives the turbine, without any secondary steam system, simplifying the plant [3]. These temperatures facilitate co-generation of electricity and hydrogen uniformly throughout the year, independently from the behavior of demand for electricity [4].

The hydrogen plant becomes a parallel, manageable load that facilitates the modulation of thermal load to the reactor, hence, with an electrical load decrease, the SCWR could produce more hydrogen and vice versa. Heat exchangers of a recuperator-type would be used for this purpose [4]. Figure 2 provides a schematic flow diagram of this concept.

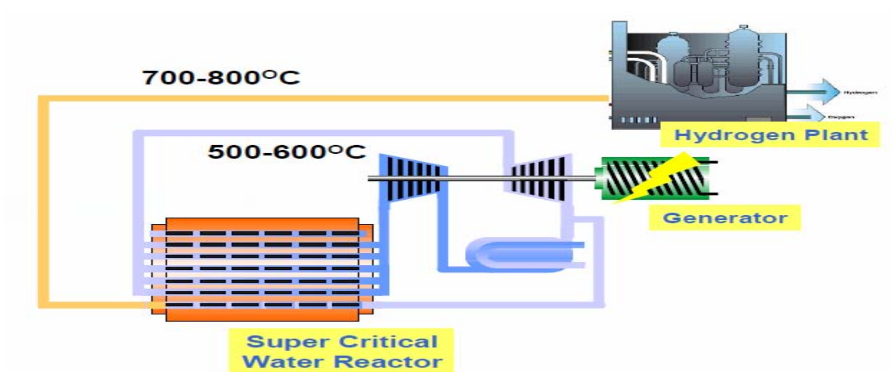

Figure 2: Cogeneration of Hydrogen with Re-Heat Through Outer Channels (4)[4]

A comparative study performed by the National Research Council [5] on hydrogen production technologies, found that hydrogen production by using thermal nuclear energy to split water can yield a source cost of 1.63 \$/kg. In a similar analysis, focused on the Sulfur-Iodine process using thermal energy from nuclear sources, Brown [6] performed a detailed techno-economic evaluation of the Sulfur-Iodine cycle, using a nuclear GT-MHR reactor. The report indicated that the cost of hydrogen yields 1.87 \$/kg, where 58% of the cost is due to the operation of the nuclear plant, and the other 42% corresponds to the operation of the S-I plant. Accordingly, the cost of high quality thermal energy used in the S-I cycle can be estimated at 9.6 \$/GJ. After considerations for fixed operational costs, capital charges at 12.5%, transportation, dispensing and CO_2 capture at 1 \$/kg CO_2, this yields a total hydrogen cost of 3.58 \$/kg H_2. The study also indicated that allocating thermal energy from the nuclear reactor for hydrogen production results in a net 50.1% energy efficiency.

In a study that presented recent Canadian advances in nuclear-based production of hydrogen by electrolysis and the thermo-chemical copper–chlorine (Cu–Cl) cycle, Naterer et al. [4] reported a thermal conversion efficiency for the Cu-Cl thermo-chemical cycle of 0.221 GJ/kg H_2, approximately 52%, although a more realistic heat-to-hydrogen efficiency of 43% was used. Orhan (7) performed an exergo-economic analysis of the Cu-Cl thermo-chemical cycle for the production of hydrogen and found the cost of hydrogen varying between 20 \$/GJ and 140 \$/GJ, for plant sizes varying from 10 tons/day to 200 tons/day H_2.

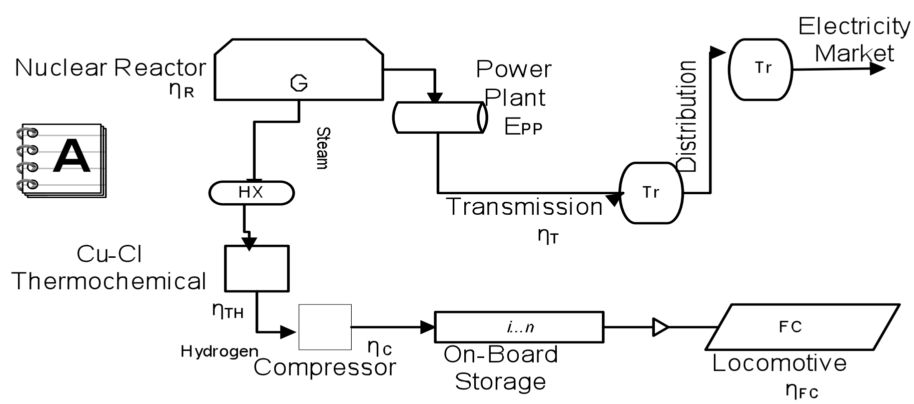

Figure 3: Thermo-chemical Cu-Cl Hydrogen and Configuration for Train Operation

Based on costing factors similar to those of the S-I cycle, a cost for thermal energy is assumed to vary from 9 \$/GJth to 84 \$/GJth (8). The process considered in this study is shown in Figure 3, integrated with train operations, where thermal energy is supplied directly from a nuclear plant via a heat exchanger. Thermal energy can also be supplied from other processes where surplus heat is available, and where primary energy sources do not pollute. It is implicit in the figure that when compared to electrolysis, the resulting efficiency of the thermo-chemical Cu-Cl cycle is higher, due to avoiding the low efficiency conversion from thermal to mechanical energy, and to electrical energy as required by electrolysis.

Because of the nature of the process, the thermo-chemical production of hydrogen becomes more competitive at larger capacities [5], [8], [9]. Also, the overall efficiency of a thermo-chemical cycle is higher when compared to electrolysis, given the direct utilization of thermal energy, which eliminates the intermediate need for electrical conversion. Figure 4 illustrates how costs associated with the capital and operations of a thermo-chemical plant contribute to the cost of hydrogen. Thermal energy contributes approximately 55% to the final cost of the hydrogen delivered to trains. This cost is estimated by taking as a reference the thermo-chemical Sulfur-Iodine cycle for the production of hydrogen. This is a process similar in concept to the Cu-Cl process, where high quality heat is extracted from nuclear or solar thermal plants, and a closed loop operation splits waters into oxygen and hydrogen. The Sulfur-Iodine cycle operates at temperatures substantially higher than the Cu-Cl cycle. In thermal energy systems, the energy cost is higher than that required for the thermo-chemical Cu-Cl cycle.

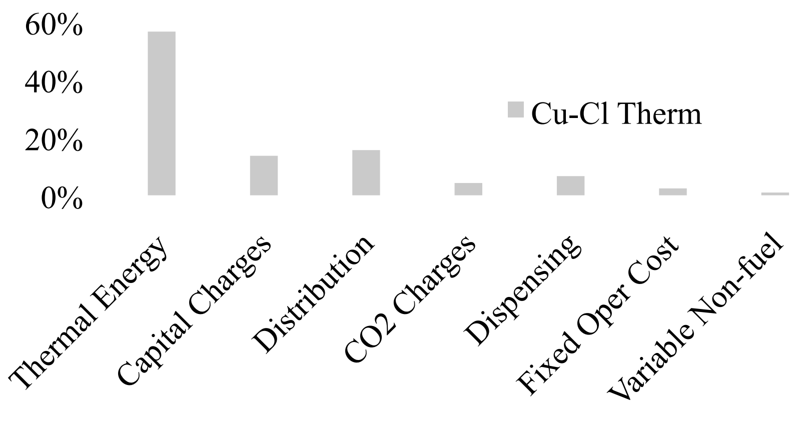

Figure 4: Cost Contributors to Thermo-chemical Hydrogen

The thermo-chemical Cu-Cl cycle for the generation of hydrogen uses thermal energy directly from the source without the intermediate production of electricity. The Cu-Cl thermo-chemical cycle is a promising technology since it can use heat available at substantially lower temperatures when compared to the Sulfur-Iodine process (530 vs. 800 ^{o}C). The lower temperature requirements make it ideal for the recovery of otherwise wasted energy from nuclear reactors or the utilization of solar concentrators at high efficiencies of conversion.

3. Greenhouse Gas Emissions

On average, a nuclear plant has a life cycle CO_2 emission rate of 3,200 tons/TWh, which is equivalent to about 0.0089 t/GJ [10]. This includes the construction and decommissioning of the entire nuclear reactor. It also includes the emissions from mining for uranium. To be consistent with other power generation sources considered in this study, this value needs to be discounted by the amounts corresponding to construction and decommissioning of the plant, which amounts to 2,220 tons/TWh for construction and 610 tons/TWh for decommissioning. The discounted value represents the emissions of CO_2 from regular operations of a CANDU reactor and it is expressed as 370 tons/TWh (0.0001 t/GJ, at least two orders of magnitude below the 0.066 tons/GJ for the OPG mix of power generation) (11)[11].

When hydrogen from electrolysis, in combination with the Ontario power mix available in 2015, is used for the operation of trains together with hydrogen fuel cells, the volume of GHGs generated accounts for 43% of the GHGs generated under direct electrification of the trains. Another option is hydrogen from a thermo-chemical process such as the Cu-Cl cycle, which emits only 25% of the GHGs emitted by direct electrification.

Powering the trains with hydrogen generated through a Cu-Cl thermo-chemical cycle using PEMFC technology, linked to a nuclear plant can significantly reduce the GHG emissions. The total CO_2 emissions from the GO transit Lakeshore operation in 2015 via electrification are calculated to be about 13,500 tons/year, while operation using electrolytic hydrogen generates 626 tons/year, and 345 tons/year, if using hydrogen from a thermo-chemical Cu-Cl cycle. On the basis of source energy, whether nuclear or the OPG mix, the utilization of heat rejected from nuclear plants, combined with hydrogen generated through a thermo-chemical Cu-Cl cycle and PEM fuel cell trains, results in the lowest level of GHG emissions, on the order of 0.10 kg/GJ. The high efficiency of the PEMFC complements the performance of thermo-chemical hydrogen production well, yielding the lowest GHG emissions at the prime mover, on the order of 0.04 kg/km (345,000 kg/year in 2015, and 488,000 kg/year by 2031).

A typical private vehicle in Ontario is utilized on average by 1.15 persons. One 10-car GO train carries 1,540 passengers at any time, or about the same number of people as 1,340 vehicles that emit 240 g/km of CO_2, implying that a 10-car train has the potential of saving 0.322 tons of CO_2 emissions per train-km when fully loaded. Considering the ridership expected by 2031 to be about 143 million passengers/year, the Lakeshore GO train operation on hydrogen averts the GHG emissions of approximately 29,850 tons of CO_2 and releases 3,900 tons CO_2, for a net CO_2 emission reduction of 25,950 tons of CO_2/year. The actual impact of CO_2 emissions reduction is significant when compared to the diesel alternative (as shown Figure 5).

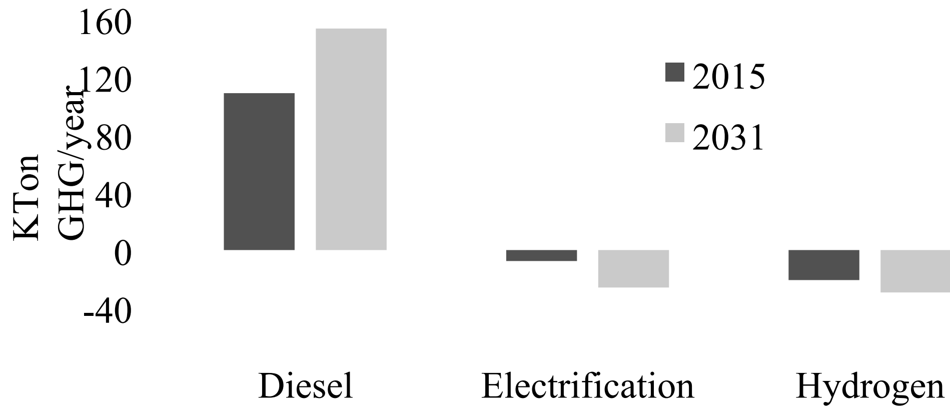

Figure 5: Total CO2 Generation / Reduction

4. Hydrogen Train

The GO Transit operates train services using push / pull locomotives with 10 or 12 double-deck units for a total capacity of 1540 passengers. The services are provided routinely from 5:30 in the morning to 1:10 in the morning using 17 diesel locomotives in the Lakeshore corridor, for which station distribution and distances are shown in Figure 6. They are used by approximately 25.5 million riders for a total of 2.47 million km per year in 2007.

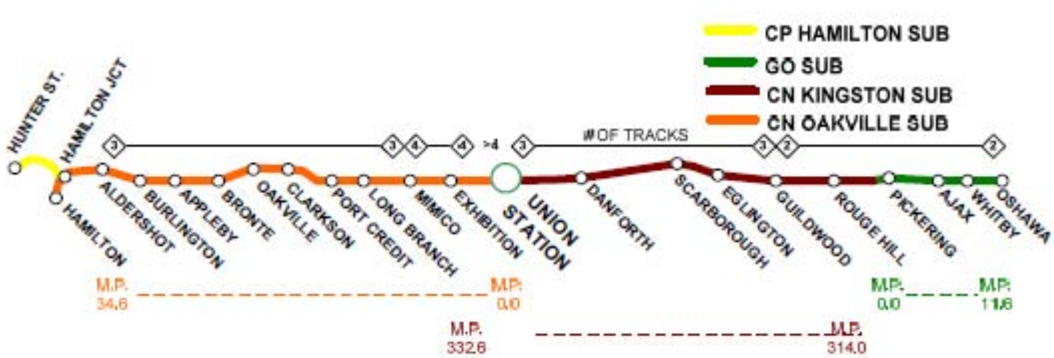

Figure 6: Train Stations along the Lakeshore Corridor [12]

GO Transit operates a combination of rail, light rail and bus services. When hydrogen generated from a thermo-chemical Cu-Cl plant is used, the train operation has a potential to result in close to zero emissions and a cost of approximately 99 $/train-km, as illustrated in Fig. 10. The cost that governments will apply to GHG emissions is not yet fully defined. Without consideration for the cost impact of GHG emissions, and at the fixed rate of 12.5% annual capital cost, fixed operational cost at 5%, and transportation to site storage and dispensing taken into consideration, the cost of generating hydrogen via the thermo-chemical Cu-Cl cycle varies with the cost of thermal energy. With a base price of 9 $/GJ, prices of thermo-chemical hydrogen production offer a relatively predictable scenario for train operation, considering thermal energy sources use either nuclear or solar energy.

Several European transit authorities have performed or are in the process of performing studies exploring the potential use of hydrogen. The Rail Safety and Standards Board (RS&SB) [13] considered a Ballard heavy-duty fuel cell power package to retrofit a Class 66 locomotive. The Locomotive Class 66 carries a 2,385 kW diesel engine that weights 14,500 kg, or 12% of the total locomotive weight. The Ballard heavy-duty package (considered as a substitute) was assumed to have a gravimetric power density of 0.175 kW/kg, for a total replacement weight of 13 tons, or 12% of the total locomotive weight. Similarly, to substitute the diesel engine in the ALP 46-A, a fuel cell power package with a gravimetric power density of 0.175 kW/kg will weigh 32 tons, which constitutes 26% of the total locomotive weight. For rail applications, although a hydrogen storage density of better than 5 MJ H_2 per litre is desirable, hydrogen stored at 350-atm reaches an energy density of 2.2 MJ/L. In terms of weight, carbon fibre vessels store hydrogen at densities of 0.06 kg/kg, which implies that for a desired capacity of 1700 kg/train, the storage system weights approximately 28 tons. Following the same approach as RS&SB, removing the weight of the diesel power cell and adding the weight of a fuel cell power system and storage tanks brings the total weight of the locomotive to 147 tons, a total increase in weight of 46%. Further research in higher energy storage densities is required to reduce the weight on board locomotives.

The costs of fuel cell power packages vary over a wide range, and future cost projections rely on mass production estimates, driven by the automobile market, in volumes and quantities that do not represent the volumes required by trucks, buses or trains. The hydrogen train study assumed a price of 500 $/kW for the cost evaluation process. The study concluded that a rail demonstration project, including a prototype design/development phase, would cost from £8 million to £10 million for a single railcar vehicle. Using a similar methodology and assumptions as RS&SB, but adapted for Ontario Canada, the cost of a fuel cell locomotive was estimated as shown in Figure 7, not including prototype design/development phase costs, and assuming a most probable cost of fuel cell power at 500 $/kW, and compressed gas storage at 800$ /kW.

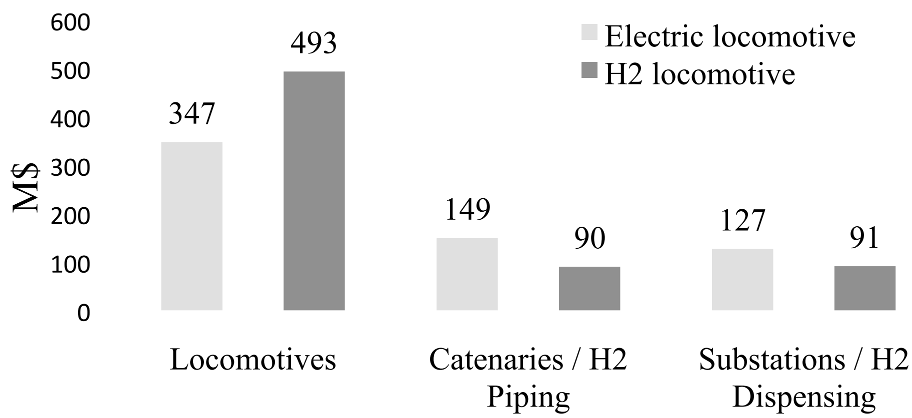

Figure 7: Cost Contributors

A Ballard heavy-duty fuel cell package was assumed to have a gravimetric power density of 0.175 kW/kg, for a total replacement weight of 13 tons, or 12% of the total locomotive weight. Similarly, to substitute the diesel engine in the ALP 46-A, a fuel cell power package with a gravimetric power density of 0.175 kW/kg will weigh 32 tons, which constitutes 26% of the total locomotive weight. Hydrogen stored at 350-atm reaches an energy density of 2.2 MJ/L, which implies that the storage system weights approximately 28 tons, based on carbon fiber vessels storing hydrogen at densities of 0.06 kg/kg. Following the same approach as RS&SB, removing the weight of the diesel power cell and adding the weight of a fuel cell power system and storage tanks brings the total weight of the locomotive to 147 tons, a total increase in weight of 46%.

A sensitivity analysis with consideration of price changes in the feedstock of various options to power the GO trains including all the factors of capital charges, thermal energy at 9 $/Gj, dispensing, storage, and emissions, indicates that the cost of hydrogen amounts to 3.77 $/kg, which implies a total cost of train operations at 5.34 $/train-km, based on a total distance traveled by Lakeshore trains in 2015 of 8.5 million km/year. Similarly, the total cost of electrical energy alone amounts to about 1.15 $/km.

The base case analysis for electrification estimated by the GO transit study assumed 24 train locomotives used by 2015 and 49 locomotives by 2031 (44 in regular use and 5 in stand-by) with each electric locomotive priced at approximately 7.2 M$. The estimated cost of the power system installed inside the locomotive, and applied in the RS&SB analysis, is 18% of the total cost of the locomotive, including the cost of power electronics and pantographs. An approximation of the cost of a fuel cell locomotive is then obtained by subtracting from the original locomotive cost, and then reinstating with the cost of a fuel cell power train plus hydrogen storage. The analysis considered the characteristics of the Ballard ALP-46A locomotive, where the fuel cell package and hydrogen storage occupies approximately 76 m^3 or 64% of the total available volume, for a total cost of 1.3 M$/Locomotive. Although this analysis considered an introductory fuel cell package price of 500 $/kW, the price of current technologies varies within a wide range that starts at approximately 117 $/kW, and reaches as high as 1,500 $/kW [14], [15].

With a large capital investment that approaches CDN $ 6.0 billion dollars, GO Transit could enhance the services for an increased ridership of more than 140 million passengers every year by 2031, to cities, and in frequencies beyond the level of services provided in 2007. The estimated cost in the report prepared for Metrolinx did not include financial charges on investment that, exception made of locomotive costs, is mainly allocated to the improvement and enhancement of rail tracks, buying of land, new bridges, new passenger stations and new maintenance sites. These investments in infrastructure are common to both electrification and hydrogen PEMFC operation, which when added to the cost of locomotive substations and catenaries in the case of electrification, and the cost of fueling stations and piping in the case of hydrogen operation, produce the estimated cost of operation per train-km as presented in Figure 8. The results are based on a 20 year planned financial life of investment and financial yearly rates varying between 12.5% and 16%.

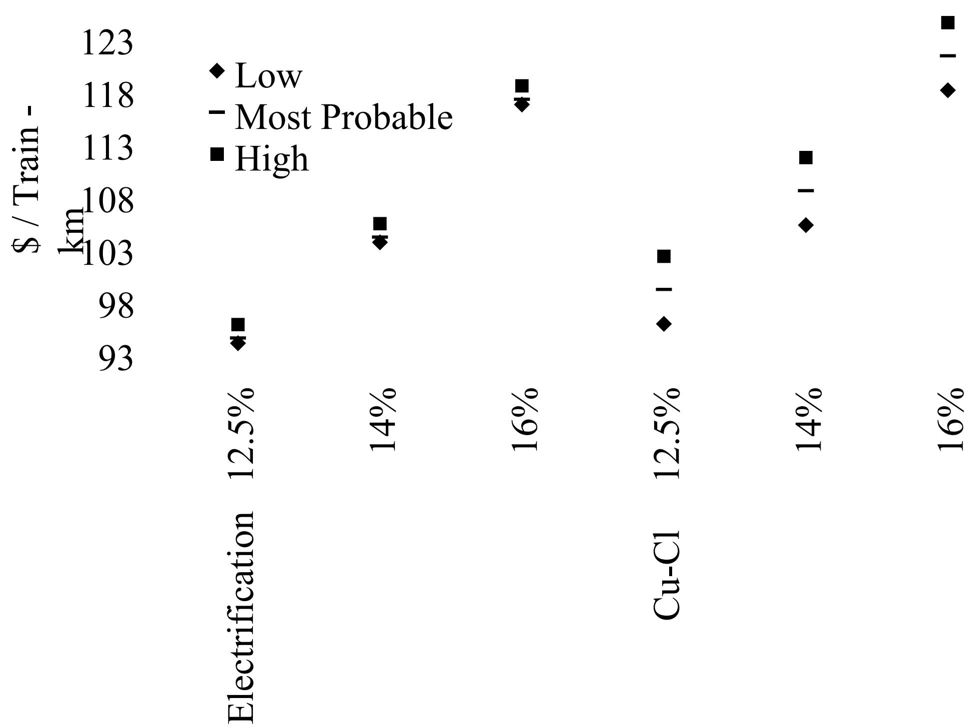

Figure 8: Projected Total Operational Cost for GO Trains

5. Conclusions

The efficient utilization of energy resources implies integration of technologies that result in generation of additional useful work. Cogeneration of hydrogen via integration of the Copper-Chlorine thermo-chemical process with thermal energy from nuclear plants results on hydrogen available in volumes adequate for application in transportation services. A single train locomotive requires up to 1700 kg of hydrogen on board; a hydrogen production rate that results unpractical and expensive for processes such as electrolysis, no withstanding the lower efficiency of the process. The analysis here assumed a cost of thermal energy from nuclear at CAN 9.0 $/GJ; a value taken from analysis performed on thermo-chemical Sulfur-Iodine processes running out from nuclear thermal energy. With consideration of all cost associated to hydrogen production, and when applied to train operations, it results in a cost of 5.34 $/train-km, a extremely high cost when compared to the electrification option of 1.15 $/km. If the cost of thermal energy from nuclear is reduced to 1 $/GJ, the impact on train operation powered by hydrogen gets reduced to 2.84 $/km. In total, taking into consideration the cost of locomotives, hydrogen storage and delivery, plus the cost of infrastructure for services projected to 2031, the hydrogen operation results in a most probable cost of 99 $/train-km, while the equivalent service under electrification results in approximately 94 $/train-km.

Acknowledgements

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