 Accepted June 2008

HYDROGEN STORAGE FOR MIXED WIND-NUCLEAR POWER PLANTS IN THE CONTEXT OF A HYDROGEN ECONOMY

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ABSTRACT: A novel methodology for the economic evaluation of hydrogen production and storage for a mixed wind-nuclear power plant considering some new aspects such as residual heat and oxygen utilization is applied in this work. This analysis is completed in the context of a Hydrogen Economy and competitive electricity markets. The simulation of the operation of a combined nuclear-wind-hydrogen system is discussed first, where the selling and buying of electricity, the selling of excess hydrogen and oxygen, and the selling of heat is optimized to maximize profit to the energy producer. The simulation is performed in two phases: In a pre-dispatch phase, the system model is optimized to obtain optimal hydrogen charge levels for the given operational horizons. In the second phase, a real-time dispatch is carried out on an hourly basis to optimize the operation of the system as to maximize profits, following the hydrogen storage levels of the pre-dispatch phase. Based on the operation planning and dispatch results, an economic evaluation is performed to determine the feasibility of the proposed scheme for investment purposes; this evaluation is based on calculations of modified internal rates of return and net present values for a realistic scenario. The results of the presented studies demonstrate the feasibility of a hydrogen storage and production system with oxygen and heat utilization for existent nuclear and wind power generation facilities.

Keywords: hydrogen production, hydrogen storage, hydrogen economy, nuclear power, wind power, electricity markets, mixed-integer stochastic linear programming, economic evaluation.

1. NOMENCLATURE

1.1. *Parameters and constraints*

μ_{he} : hydrogen efficiency of electrolyzer (kg/MWh)

μ_{oe} : oxygen efficiency of electrolyzer (Nm^3/MWh)

μ_{hc} : hydrogen efficiency of compressor (kg/MWh)

μ_{oc} : oxygen efficiency of compressor (Nm^3/MWh)

μ_{ef} : electrical efficiency of stationary fuel cell (kg/MWh)

μ_{hf} : heat efficiency of stationary fuel cell (kg/MWh)

c^H : hydrogen selling price (CAD/kg)

c^O : oxygen selling price (CAD/Nm^3)

c^{HEAT} : heat selling price (CAD/MWh)

$P_{\max}^{NET}$: transmission line capacity (MW)

$V_{\max}^{STG}$: maximum storage level (kg)

$P_{\max}^{DIS}$: maximum stationary fuel cell electricity production (MW)

$P_{\min}^{DIS}$: minimum stationary fuel cell electricity production (MW)

$P_{\max}^{CH}$: maximum electrolyzer electricity consumption (MW)

$P_{\min}^{CH}$: minimum electrolyzer electricity consumption (MW)

N_w : number of wind scenarios

N_p : number of price scenarios

T : number of time steps

1.2. *Variables*

P_W : wind power plant production (MW)

P_N : nuclear power plant production (MW)

P_G : total wind-nuclear power plant production (MW)

P_E : electrolyzer consumption (MW)

P_F : fuel cell electricity sales (MW)

P_H : fuel cell heat sales (MW)

P_M : power exchange with the market (MW)

V_{ch} : hydrogen production by electrolyzer (kg)

V_{dis} : hydrogen consumption by fuel cells (kg)

V_O : oxygen sales to the oxygen market (Nm^3)

V_H : hydrogen sales to the hydrogen market (kg)

$P_{w,p,i}^{G}$: used wind-nuclear power for wind scenario *w* at hour *i* (MW)

$P_{w,p,i}^{CH}$: electricity consumed by electrolyzer for wind scenario *w* and price scenario *p* at hour *i* (MW)

$P_{w,p,i}^{DIS}$: fuel cell electricity produced and sold for wind scenario *w* and price scenario *p* at hour *i* (MW)

$P_{w,p,i}^{HEAT}$: heat produced and sold for wind scenario *w* and price scenario *p* at hour *i* (MW)

V_i^{STG} : storage level at hour *i* (kg)

$V_{w,p,i}^{H}$: hydrogen sold to the hydrogen market for wind scenario *w* and price scenario *p* at hour *i* (kg)

$V_{w,p,i}^{O}$: oxygen produced and sold for wind scenario *w* and price scenario *p* at hour *i* (Nm^3)

$\alpha_{w,p,i}$: on/off status of stationary fuel cells for wind scenario *w* and price scenario *p* at hour *i*

$\beta_{w,p,i}$: on/off status of electrolyzers for wind scenario *w* and price scenario *p* at hour *i*

$\hat{P}_i^{G}$: actual used wind-nuclear production at hour *i* (MW)

$\hat{P}_i^{CH}$: actual electricity consumed by electrolyzer at hour *i* (MW)

$\hat{P}_i^{DIS}$: actual fuel cell electricity produced and sold at hour *i* (MW)

$\hat{P}_i^{HEAT}$: actual heat produced and sold at hour *i* (MW)

$\hat{V}_i^{STG}$: actual storage level at hour *i* (kg)

$\hat{V}_i^{H}$: actual hydrogen sold to the hydrogen market at hour *i* (kg)

$\hat{V}_i^{O}$: actual oxygen produced and sold at hour *i* (Nm^3)

$\hat{\alpha}_i$: actual on/off status of stationary fuel cells at hour *i*

$\hat{\beta}_i$: actual on/off status of electrolyzers at hour *i*

$\hat{V}_d^{STGEND}$: storage level in the last hour of the current day (kg)

$\hat{R}_i$: Revenues at hour *i* (CAD)

$\hat{R}_i^{WH}$: Revenues without hydrogen system at hour *i* (CAD)

1.3. Input data

p_w : probability of wind scenario *w*

p_p : probability of price scenario *p*

$c_{p,i}^M$: market price forecast for price scenario *p* in hour *i* (CAD/MWh)

$W_{w,i}$: wind and nuclear generation forecast for wind scenario *w* in hour *i* (MW)

$\hat{c}_i^M$: actual market price in hour *i* (CAD/MWh)

$\hat{W}_i$: actual wind and nuclear generation in hour *i* (MW)

1.4. Abbreviations

RES: renewable energy sources
NPP: nuclear power plant
MISLP: mixed-integer stochastic linear programming
MIRR: modified internal rate of return
NPV: net present value
IRR: internal rate of return
WACC: weighted average cost of capital
O&M: operation and maintenance
CAD: Canadian dollar
USD: United States dollar
OPA: Ontario Power Authority
IESO: Independent electricity system operator
PEM: proton exchange membrane
HOEP: hourly Ontario electricity price
MAE: mean absolute error
p.u.: per unit
BCS: base case scenario
FE: sub-scenario considering forecast error
NFE: sub-scenario not considering forecast error
FC: sub-scenario considering fuel cells
NFC: sub-scenario not considering fuel cells
OCE: Ontario centre of Excellence
NSERC: National Sciences and Engineering Research Council of Canada

2. Introduction

There is a growing need for an energy carrier to replace dwindling and emission generating fossil fuel based energy sources in the future, especially in the transportation sector. The concept of a Hydrogen Economy has been proposed to address this problem [1], [2], in which there is a proposed economy where energy is stored and carried as hydrogen.

Some authors argue that the Hydrogen Economy does not make sense because of lower well-to-wheel efficiencies compared to the so called “electron economy”, which is based on electricity as the main energy carrier [3]. However, this analysis is missing the consideration of realistic bulk primary energy sources for hydrogen production (e.g. novel thermo-chemical cycles and high temperature electrolysis [4]), which may achieve hydrogen production efficiencies of more than 45%, thus lowering total costs and making large-scale hydrogen production economically feasible; these production methods combined with large-scale hydrogen transportation (e.g. by hydrogen pipelines or shipping) should make hydrogen an efficient energy carrier that might replace liquid fossil fuels in the transportation sector in the future. Furthermore, electricity storage issues, such as low range of electric vehicles compared to hydrogen fueled vehicles due to low energy density of batteries, limit the use of electricity as an energy carrier in the transportation sector [5], also battery recharge times and service lifetimes will have to significantly improve for purely electrical systems to become more acceptable to the transportation market. Finally, hydrogen integrated into electrical power systems could be a possible solution to the electricity storage problem, thus facilitating the increased use of intermittent renewable energy sources (RES) such as wind and solar, and reducing CO_2 emissions and air pollution produced by power systems [6].

Several issues have to be considered for the Hydrogen Economy to become a reality. The transition period to a fully implemented Hydrogen Economy, specifically a period of time where infrastructure and consumption growths are considered, is one of these issues. A frequently discussed option for this transition period is small-scale production of hydrogen using the hydrolysis process together with electric power systems [7]. A blend of nuclear and wind energy is proposed in [8] to provide emission-free and economically feasible hydrogen production. These studies are based on low electrolyzer cost assumptions, and are generally lacking a detailed economic evaluation and sensitivity analyses of possible investment scenarios.

Hydrogen has been also researched as an electricity storage option. Thus, in [9], the technical and financial feasibility of hydrogen as an energy carrier is researched for a stand-alone application of renewable energy sources (RES) in Australia, with the results showing that electricity produced by such system is more expensive than the electricity for domestic customers connected to the grid. It is further shown in [10] that hydrogen storage is not yet fully competitive compared to battery storage due to its low round-trip efficiency and high investment, operation and maintenance costs. In [11], the optimal operation of hydrogen storage together with intermittent RES (e.g. wind) on the European electricity markets is discussed; the results suggest that hydrogen storage considerably increases the income of the producer, and byproducts of electrolysis and stationary fuel cell usage, such as oxygen and heat, might further improve the hydrogen system economic performance. The authors in [12] present an economic viability study of hydrogen storage for different round-trip efficiencies, concluding that hydrogen storage is not economically competitive at the present state of technological development. In this context, hydrogen storage is further investigated in [13], where oxygen and heat byproducts are considered to improve the hydrogen system economic viability; however, the results of the study show that the resulting profits still do not justify the investment. In none of these papers, the possibility of hydrogen utilization in the context of a Hydrogen Economy (e.g. use of hydrogen for transportation) has been considered.

To address several of the aforementioned shortcomings in the existing technical literature, the current paper examines the feasibility of a hydrogen system for combined electricity storage and hydrogen production purposes, with utilization of byproducts such as oxygen and hydrogen, in the context of a Hydrogen Economy. The proposed study methodology is somewhat similar to that used in an earlier work; thus, the presented studies are based on a two stage analysis approach together with economic feasibility analysis.

In Section III, the proposed models and analysis techniques are described in detail. The system data used for the proposed studies is discussed and justified in Section IV, in the context of the Ontario electricity market. Section V presents and discusses the results obtained from the proposed models and data, and the main contributions and the conclusions of the presented studies are presented in Section VI.

3. Simulation Methodology

The simulation methodology starts with an optimization of the hourly operation of the system, which constitutes the first stage of the economic evaluation process. This yields daily profits which are then aggregated for a year and used as an input in the second stage of the economic evaluation procedure where financial indices (e.g. internal rate of return) are calculated based on constant profits throughout the systems' lifetime, following a similar procedure to that proposed in [14].

This study considers a system consisting of a nuclear power plant (NPP) and a wind farm selling electricity to the Ontario electricity market, according to market rules described by the Independent Electricity System Operator [15], [16], [17], is studied here. This is a realistic scenario for southwestern Ontario with a nuclear power producer, i.e. Bruce Power, and a number of large scale wind farms located nearby. The proposed system includes hydrogen storage and distribution facilities according to the model depicted in Fig. 1. The system includes hydrogen facilities for electricity storage and hydrogen selling, with these facilities being located near the load. It is assumed that part of the electricity production can be stored as hydrogen in periods of low electricity prices and sold back to the grid at high-price periods, or sold to the hydrogen market to optimize profits. Oxygen and heat utilization is also considered in the model.

The detailed electrolyzer model, with compressors for hydrogen and oxygen, is illustrated in Fig. 2, as per the notation defined in Section I. Observe the decoupling of the electrolyzer into two branches: the left branch represents the oxygen flow, and the right branch depicts the hydrogen flow through the electrolyzer and compressors. This figure also depicts the detailed stationary fuel cell model, which is decoupled, with the left branch representing the electricity production and the right branch the heat production; thus, the fuel cell is actually a combined heat and power production unit. The operation of the system depicted in Fig. 1 is performed using the approach presented earlier in [13] and [14], which was developed based on [18] and [19]. Thus, a two-level study approach is used, where dispatch levels are first obtained one-day ahead, based on a mixed integer stochastic linear programming (MISLP) model. The system's real-time operation is then simulated based on real-time data, so that financial parameters, such as energy sold, energy purchased, income, etc., can be calculated based on the results. In these models, wind production and electricity prices are considered to be stochastic input parameters, and hydrogen, heat and oxygen selling is also considered. The hydrogen storage operational constraints are modeled in both stages based on a method introduced in [20].

3.1. Pre-dispatch

The following optimization model for obtaining the one-day-ahead dispatch levels is used, where the only variable linking together operating hours and days being storage content, i.e. the storage content variable is fixed, making the model time dependent but not scenario dependent:

$$\begin{aligned}\max \quad & \sum_{w=1}^{Nw} p_w \cdot \sum_{p=1}^{Np} p_p \cdot \sum_{i=1}^{T} (c_{p,i}^{M} (P_{w,p,i}^{G} + P_{w,p,i}^{DIS} - \\ & P_{w,p,i}^{CH}) + c^{H} V_{w,p,i}^{H} + c^{O} V_{w,p,i}^{O} + c^{HEAT} P_{w,p,i}^{HEAT})\end{aligned} \tag{1}$$

subject to:

$$P_{w,p,i}^{G} \le P_{\max}^{NET} \tag{2}$$

$$0 \le P_{w,p,i}^{G} \le W_{w,i} \tag{3}$$

$$\begin{aligned}V_i^{STG} &= V_{i-1}^{STG} + \mu_{he} \cdot \frac{1}{\left(1 + \dfrac{\mu_{oe}}{\mu_{oc}} + \dfrac{\mu_{he}}{\mu_{hc}}\right)} \cdot P_{w,p,i}^{CH} \\ & - \mu_{ef} P_{w,p,i}^{DIS} - V_{w,p,i}^{H}\end{aligned} \tag{4}$$

$$V_0^{STG} = \hat{V}_{d-1}^{STGEND} \tag{5}$$

$$\alpha_{w,p,i} \cdot P_{\min}^{DIS} \le P_{w,p,i}^{DIS} \le \alpha_{w,p,i} \cdot P_{\max}^{DIS} \tag{6}$$

$$\begin{aligned}&\beta_{w,p,i} \cdot \left(1 + \frac{\mu_{oe}}{\mu_{oc}} + \frac{\mu_{he}}{\mu_{hc}}\right) \cdot P_{\min}^{CH} \le P_{w,p,i}^{CH} \\ &\le \beta_{w,p,i} \cdot \left(1 + \frac{\mu_{oe}}{\mu_{oc}} + \frac{\mu_{he}}{\mu_{hc}}\right) \cdot P_{\max}^{CH}\end{aligned} \tag{7}$$

$$0 \le V_i^{STG} \le V_{\max}^{STG} \tag{8}$$

$$V_{w,p,i}^{O} = \mu_{oe} \cdot \frac{1}{\left(1 + \frac{\mu_{oe}}{\mu_{oc}} + \frac{\mu_{he}}{\mu_{hc}}\right)} \cdot P_{w,p,i}^{CH} \tag{9}$$

$$P_{w,p,i}^{HEAT} = \frac{\mu_{ef}}{\mu_{hf}} P_{w,p,i}^{DIS} \tag{10}$$

where all variables are properly defined in Section I. In this model, $c_{p,i}^{M}$ and $W_{w,i}$ are stochastic parameters. The binary variables $\alpha_{w,p,i}$ and $\beta_{w,p,i}$, representing on/off statuses of the electrolyzer and stationary fuel cells in (6) and (7), make the model a MISLP problem. Equation (1) describes the objective function, and (2) limits the production and consumption of the model to available line capacities. In (3), the actual wind production is limited by the forecasted wind-nuclear production associated with the wind forecast 'w' at hour 'i'. Equations (4)-(8) correspond to the operation of the hydrogen storage system, where two consecutive days are linked via actual hydrogen storage content at the end of the day using (5). Finally, (9) and (10) are used to calculate the oxygen and heat production from electrolyzers and stationary fuel cells, respectively. The use of the efficiencies for the calculation of hydrogen and oxygen productions in the electrolyzer is the result of the two branch model in Fig. 2. The optimization period is assumed to be one day, with hourly resolution.

A one-day forecasting horizon is chosen, since a longer horizon would not improve the overall performance of the system, as the forecasting error of electricity prices and wind speeds increase with forecasting length [11], [15]. On the other hand, a shorter pre-dispatch optimization horizon would result in increased number of local optima, without the ability to profit from all wind-power and price fluctuations.

3.2. Real-time Dispatch

A simple real-time operating strategy that follows the scheduled hydrogen storage obtained from the solution of the MISLP problem (1)-(10) is used here. The hydrogen that is not sold as electricity is sold to the transportation hydrogen market to maximize profits. The optimization is also done on an hourly basis for one day, and the constraints are the same as in the previously described optimization model. Thus, the resulting real-time MILP optimization model is defined as follows:

$$\begin{aligned} \max \quad & (\hat{c}_i^{M} (\hat{P}_i^{G} + \hat{P}_i^{DIS} - \hat{P}_i^{CH}) \\ & + c^{H} \hat{V}_i^{H} + c^{O} \hat{V}_i^{O} + c^{HEAT} \hat{P}_i^{HEAT}) \end{aligned} \tag{11}$$

subject to:

$$\hat{P}_i^{G} \le P_{\max}^{NET} \tag{12}$$

$$0 \le \hat{P}_i^{G} \le \hat{W}_i \tag{13}$$

$$\begin{aligned} \hat{V}_i^{STG} &= \hat{V}_{i-1}^{STG} + \mu_{he} \cdot \frac{1}{\left(1 + \frac{\mu_{oe}}{\mu_{oc}} + \frac{\mu_{he}}{\mu_{hc}}\right)} \cdot \hat{P}_i^{CH} \\ & - \mu_{ef} \hat{P}_w^{DIS} - \hat{V}_i^{H} \end{aligned} \tag{14}$$

$$\hat{V}_1^{STG} = V_i^{STG} \tag{15}$$

$$\hat{V}_0^{STG} = \hat{V}_{d-1}^{STGEND} \tag{16}$$

$$\hat{\alpha}_i \cdot P_{\min}^{DIS} \leq \hat{P}_i^{DIS} \leq \hat{\alpha}_i \cdot P_{\max}^{DIS} \tag{17}$$

$$\hat{\beta}_i \cdot \left(1 + \frac{\mu_{oe}}{\mu_{oc}} + \frac{\mu_{he}}{\mu_{hc}}\right) \cdot P_{\min}^{CH} \leq \hat{P}_i^{CH} \leq \hat{\beta}_i \cdot \left(1 + \frac{\mu_{oe}}{\mu_{oc}} + \frac{\mu_{he}}{\mu_{hc}}\right) \cdot P_{\max}^{CH} \tag{18}$$

$$0 \leq \hat{V}_i^{STG} \leq V_{\max}^{STG} \tag{19}$$

$$\hat{V}_i^{O} = \mu_{oe} \cdot \frac{1}{\left(1 + \frac{\mu_{oe}}{\mu_{oc}} + \frac{\mu_{he}}{\mu_{hc}}\right)} \cdot \hat{P}_i^{CH} \tag{20}$$

$$\hat{V}_d^{STGEND} = \hat{V}_T^{STG} \tag{21}$$

$$\hat{P}_i^{HEAT} = \frac{\mu_{ef}}{\mu_{hf}} \hat{P}_i^{DIS} \tag{22}$$

Observe that this model is similar to the pre-dispatch model (1)-(10); however, in this case, there are no stochastic parameters and the optimization model corresponds to one-hour only, which is then solved on an hourly basis for a 24 h period.

The income obtained from the hydrogen storage system is the difference between the total income of the wind-nuclear system with hydrogen, and the income of the system without hydrogen. The income with the hydrogen system is calculated as follows:

$$\hat{R}_i = (\hat{c}_i^M (\hat{P}_i^G + \hat{P}_i^{DIS} - \hat{P}_i^{CH}) + c^H \hat{V}_i^H + c^O \hat{V}_i^O + c^{HEAT} P_{w,p,i}^{HEAT}) \tag{23}$$

On the other hand, the income without the hydrogen system is calculated using the following equation:

$$\hat{R}_i^{WH} = \hat{c}_i^M \cdot \min(P_{\max}^{NET}, \hat{P}_i^G) \tag{24}$$

3.3. Economic Analysis

The modified internal rate of return (MIRR), referred to also as growth rate of return, and the net present value (NPV) economic indices are used in this paper [21]. The MIRR was chosen over the simple rate of return (IRR) index due to a better assessment of negative cash flow impacts after the initial investment year; this is done by discounting the negative cash flows with respect to the project’s first year based on the finance rate. The positive cash flows, on the other hand, are discounted with respect to the last year of the project based on the reinvestment rate.

The finance rate in this article is assumed to be equal to weighted costs of capital (WACC), and the reinvestment rate is assumed to be the same as typical discount rates used in the industry. The components taken into account in the calculation of cash flows are the following: initial investment costs including transportation and installation; replacement investment costs (for replacements of worn-down assets); operation and maintenance (O&M) costs; revenues; depreciation (amortization); taxes; and salvage value.

4. ACTUAL SYSTEM SETUP

The nuclear-wind system is assumed to be located in Bruce County in Ontario, Canada, because Bruce Power's NPP operates in the region and the Ripley Wind Farm Project being built there; hence, any investment or O&M costs associated with existing units are disregarded in the economic analysis. The hydrogen storage system is assumed to be located in the greater Toronto area, which is Ontario's major load center, and assumes that this region has a well-developed hydrogen, heat and oxygen markets. The chosen currency is Canadian dollars (CAD), which is converted from US dollars (USD) at a rate of 1 USD per 1.04923 CAD. Since the prices of equipment cannot be properly forecasted, fixed equipment prices are assumed here. Furthermore, exchange rate changes are assumed to be small, and hence these are not considered to have a significant impact on the system economics. These are typical assumptions used in the technical literature [21].

A number of preliminary studies were performed based on the developed models and the methodology presented in Section 3 and the data provided in Section 4. These preliminary studies showed that the number of wind scenarios does not impact the operation of the system due to sufficient capacity of the transmission lines, and the fact that the energy production from Bruce Power's NPP is assumed to be constant and fed directly into the grid, except for the amount that is used to cover for the unavailability of wind power. Therefore, the NPP's power is used only to increase the utilization of the hydrogen subsystem, which obtains most of its required energy from the wind farm. Hence, the operation of the hydrogen system becomes basically price dependant rather than wind speed dependant, given the high nuclear power production capacity compared to the wind power production. The wind variability, as seen from the hydrogen system perspective, can be therefore neglected in the subsequent analysis. According to this reasoning, only one wind scenario is considered in the article. On the other hand, 30 price scenarios are generated for each optimization period to represent the stochastic price behavior, with the optimization period being considered to be 24 hours with hourly resolution. The various studied scenarios are described in more detail in Section 4.4.

The profit calculation is done for one year, which is then used in economic evaluations. The project lifetime is assumed to be 20 years. The finance rate is assumed to be 6.6% as per typical values for North America [22]. The reinvestment rate is assumed to be equal to a discount rate of 10%, as in [23].

Two governmental/provincial tax rates are applied in Canada depending on yearly income [24]. However, a provincial tax incentive is assumed because of production of hydrogen from RES; thus, an 18.62% tax rate is used here regardless of income [25]. Furthermore, a government investment support from the Ontario Power Authority (OPA), due to emission free hydrogen production from RES and NPP, in the form of a standard offer program [25], is assumed to cover 25% of the initial investment costs; this support does not include replacement costs for worn-down equipment after its lifetime. A uniform salvage value of equipment at the end of its lifetime is assumed to be 10% of the investment costs [24]. The O&M costs are assumed to be 2% per year of initial investment [24]. It is assumed that sufficient quantities of fresh water are available free of charge for the electrolysis process at this location, due to the vicinity of the Great Lakes.

4.1. Wind Power Plant

The Ripley Wind Power Project is one of Suncor Energy Products Inc. and Acciona Wind Energy Canada Inc.'s latest generation developments. The wind farm is located on the eastern shores of lake Huron in Huron-Kinloss Township, approximately 220 km west of Toronto and 140 km north of London. The wind farm consists of 38 Enercon E82 2 MW wind turbines with total capacity of 76 MW [26]. The wind speed data for 2004 were provided by Suncor and wind farm production was calculated based on the Enercon E82 wind-turbine model represented in Fig. 3; this model was obtained using a curve fitting process based on the producer's data [27].

4.2. Nuclear Power Plant and Transmission Line

Bruce Power is Canada's first privately owned nuclear power plant, with installed capacity of 4820 MW, and is located approximately 250 kilometers northwest of Toronto. Because Bruce power is privately owned, the actual production profile and income data are confidential.

In 2004, Bruce power produced 33.6 TWh of electricity [28], which gives them a capacity factor of 82% that is equal to 3952.4 MW of constant electricity production. It is assumed here that 3000 MW of band electricity is sold to Ontario's ISO (IESO) on a bilateral contract, and the remaining 952.4 MW are sold to the electricity market or converted to hydrogen. A 500 kV transmission line Bruce-Milton together with other lower-voltage lines is assumed to have a capacity of 5000 MW. The refurbishment of Bruce A reactors 1 and 2, which will add an additional 1500 MW of installed capacity in 2010 and 2011, respectively, is not considered to impact the system operation and revenues, since the transmission capacity will likely increase when these reactors come into the operation. Another work, [14], considered the impact of the transmission line constrain, should it become constrained in the future.

4.3. *Hydrogen Storage System*

The hydrogen storage system is dimensioned to have the same capacity as the wind farm. The corresponding technical and financial data are listed in Table I. The NPP is assumed to provide required electricity in periods of low electricity production from wind. The Hydrogenics HySTAT-A IMET 1000 electrolyzers are assumed for the system [29]; since the prices of such units are confidential, a price of 1437.45 CAD/kW (1370 USD/kW) is used here, chosen from the prices reported in [8] and [30].

The hydrogen storage is dimensioned to be capable of storing 12 consecutive hours of hydrogen production, according to the assumption that the system's operation will be optimized in 24 hour time intervals, and peak price is reached in the afternoon. The hydrogen storage data used here are taken from [31]. The oxygen storage is assumed to be the same as hydrogen storage, which means that 14 vessels are used for storing hydrogen and oxygen, respectively. Two compressors are assumed: one for hydrogen and one for oxygen compression [20]; technical and financial parameters (except efficiencies) are taken from [31].

The stationary fuel cell array was designed to have the same hydrogen consumption capacity as is the hydrogen output of the electrolyzers. Hydrogenics HyPM 500 series proton exchange membrane (PEM) stationary fuel cells are assumed here, with technical parameters taken from [32], except for the thermal efficiency which is obtained from [20]. A moderate 1000 USD/kW price is assumed in this paper based on [8], [30] and [33], due to probable large scale production of stationary fuel cells with the corresponding economies of scale in the next 20 years, and due to the large-scale application in the discussed system setup. The combined heat and power efficiency of the stationary fuel cell is 83%, according to fuel cell parameters in the Table I.

The hydrogen selling price is taken as bulk hydrogen price produced from natural gas in 2020 [33], and is uniformly used throughout the paper. The bulk pre-tax price of hydrogen for different natural gas prices is reported in [34], where at the expected price of gas in 2020, the hydrogen production price is assumed to be 2.74 USD/kg. With carbon and sales taxes included [33], the selling wholesale hydrogen price becomes 4.35 CAD/kg, which is a conservative price since it only covers the production costs. Note that, since 1 kg of hydrogen yields about the same energy as 1 gallon (3.8 l) of gasoline [3], a car running on a 50%-efficiency fuel cell, would cost less to operate (0.035 CAD/km) than a 20%-efficiency combustion engine (0.072 CAD/km), assuming a gasoline price of 0.95 CAD/l (3.44 USD/gal) and fuel consumption of 13.2 km/l (27 mpg) [35]. Furthermore, there are other potential markets for hydrogen besides the transportation market, such as industrial (including an emerging lift truck market), electricity, and back-up power [36].

The volumetric price of oxygen is assumed to be 0.17 CAD/Nm^3 (0.12 CAD/kg when an oxygen density of 1.429 kg/Nm^3 is considered), based on information provided by an Ontario oxygen producer representative; this price includes storage, compression and piping to the end consumer. The demand of oxygen is assumed here to be significant, for applications such as waste dissolvent and other industrial uses.

The heat price is assumed to be equal to gas-heating price without the distribution, storage and dispensing costs. Thus, the price of gas was 8.77 CAD/MBtu (29.93 CAD/MWh) in the Waterloo region as of August 2007; if 90% heat utilization efficiency from gas is assumed, heat prices would be 33.24 CAD/MWh. The temperature of water from the PEM stationary fuel cells is assumed to be high enough for district water heating.

Additional price justifications and system details can be found in [13] and [14].

4.4. *Electricity Price Forecasts*

A simple electricity price forecasting model was developed assuming a normal distribution of electricity price forecasts around actual electricity prices. Therefore, the price forecasts were generated by adding error to the actual hourly Ontario electricity price (HOEP), using random numbers generated based on a normal distribution with a mean value μ=0 CAD and standard deviation σ=13.8 CAD. The maximum relative error is limited to 30% of the HOEP, which is chosen so that the mean absolute errors (MAE) are similar to these obtained with the forecast models reported in [15]. The yearly HOEP for 2005 are used for this study; thus, the mean HOEP is 46.38 CAD/MWh. It should be mentioned that these prices are highly volatile compared to other markets [37].

5. RESULTS AND DISCUSSION

The AMPL mathematical modeling language together with the CPLEX solver is used in this work for solving the proposed mixed integer optimization models. This solver is based on state-of-the-art branch and cut algorithms to solve the given optimization problems, which are basically mixed integer linear programming (MILP) optimization models, thus obtaining the best optima for a particular set of input parameters [38]. MATLAB is used for calculating various economic indices in the second stage of economic evaluation.

5.1. Pre-dispatch and Actual Dispatch

The pre-dispatch model (1)-(10) and dispatch model (11)-(24) were solved for one year operation of the system previously described. The real-time dispatch results obtained for a typical day are presented in Fig. 4, where the electrolyzer and hydrogen storage operations are depicted together with the electricity prices; the selling of hydrogen is also shown in the figure. Observe that the real-time price is the input for the real-time dispatch optimization model, and the profits with and without hydrogen are the results of the model. Results show constant hydrogen production throughout the day, because the electricity prices are relatively low; hydrogen is then sold to the market when the storage is full. Note that this is only one optimal system dispatch solution; profits would be basically the same if hydrogen is sold without storing it. All variables are normalized with respect to their maximum values and are hence presented in per unit (p.u.)

The revenues with and without the hydrogen storage system are shown in Fig. 5, together with the resulting cumulative profit, which is a cumulative sum of the differences between the revenues with and without the hydrogen storage system. Observe that the cumulative profit is negative at the early hours of system operation, since the electricity is being bought and stored as hydrogen in this period, and becomes positive when the hydrogen is sold to the market; the cumulative profit at the last hour of operation in this figure is the total profit made by the hydrogen system for the day. One can readily show that the electrolyzer is utilized at prices of electricity lower than 91.56 CAD/MWh, based on hydrogen and oxygen prices and the electrolyzer and compressor efficiencies. Fuel cells, on the other hand, can be shown to be utilized at electricity prices higher than 266 CAD/MWh for the assumed fuel-cell electrical and heat efficiencies, and based on the given prices of heat and hydrogen; this is consistent with the simulation results, which indicate that the fuel cells are seldom utilized to generate electricity (i.e. they are only employed when electricity prices are high).

5.2. Scenario without Oxygen and Heat Utilization

To be able to properly assess the impact of heat and oxygen utilization, results of a system without the use of these byproducts are presented in Table II. Oxygen compressors and storage vessels are neglected in this case, since the oxygen is not utilized. Both the scenario without oxygen and heat utilization and the base case scenario (BCS) are further divided into four sub-scenarios based on some preliminary test results; these sub-scenarios consider price forecasts with (FE) and without error (NFE), and a hydrogen storage system with (FC) and without stationary fuel cells (NFC). The results in Table II indicate that the hydrogen system is economically viable for all four studied cases. Some additional calculations show these results to be similar to the results with heat utilization only, due to low fuel cell use. Note that the investment costs shown in the table represent only 75% of the total investment costs due to the assumed governmental support.

5.3. Base Case Scenario (BCS)

The results for the BCS are presented in Table III, and show the profitability of hydrogen storage system for all four sub-scenarios. The NPV and MIRR are shown to be higher compared to the scenario without oxygen and heat utilization presented in Table II, which makes the option of using oxygen and heat more economically attractive. The low utilization of stationary fuel cells and the higher profitability of hydrogen system without stationary fuel cells suggest that these fuel cells are redundant to the system despite additional heat utilization; the same can be observed in the scenario without oxygen and heat use. Thus, the hydrogen system is mainly utilized for hydrogen production purposes rather than electricity storage in both cases. These results are consistent with the findings reported in [8], [14], [35] and [39]. The consistency of the results is also confirmed when comparing these results with those in other papers studying the economic viability of hydrogen for the sole purpose of electricity storage, as in [9] and [10], where it is shown that hydrogen is not economically viable for these purposes. Furthermore, since the hydrogen prices considered in the article are those from an SMR hydrogen production process using natural gas, one can observe that electrolytic hydrogen production is profitable compared to the hydrogen from the SMR process.

It can be further concluded from Tables II and III, that the price forecast error does not have any considerable impact on system economics; however, for different hydrogen and electricity prices and efficiencies, these forecasts might have a more significant effect.

The nominal and discounted cumulative cash flows of the sub-scenarios FC and NFC with forecasting error are presented in Fig. 6. The change in the cash flow in year ten is due to the replacement of electrolyzers because of an assumption made of their relatively short in-service lifetime. This change reflects the scrap value of replaced electrolyzers, costs of new electrolyzers, and profits from the hydrogen system in the tenth year of the project.

5.4. *Sensitivity Analyses*

Sensitivity analyses are performed to account for possible technology advances and price changes in the future. Through these studies, thresholds at which the system becomes economically viable are obtained, with respect to different varying parameters, yielding minimal prices and efficiencies for which the system may become feasible. The sensitivities with respect to the following parameters were studied:

- Electrolyzer hydrogen and fuel-cell electrical efficiencies.
- Hydrogen selling prices.
- Oxygen selling prices.

The impact of equipment prices were studied considering fuel cells as part of the system, which is a conservative assumption, since the results from the BCS suggest that the profitability is higher when fuel cells are disregarded. The results of the previous analyses show no considerable dependency on price forecast errors; hence, these errors were not considered in the studies presented here.

5.4.1. *Hydrogen Selling Price*

Since hydrogen prices may vary in the future, depending on the development of hydrogen markets and a Hydrogen Economy, the impact of different hydrogen selling prices is investigated in this section; these prices are assumed to vary from 2 to 8 CAD/kg (approximately half to double of the assumed price in the BCS). The utilization rates and profits with respect to different hydrogen selling prices are shown in Fig. 7. The results show almost linear dependency of profit with regards to hydrogen selling price. The electrolyzer utilization increases and reaches almost 100% utilization at high hydrogen prices.

The corresponding MIRR indices are presented in Fig. 8, for different equipment cost reductions. Note that the 10% MIRR threshold, in this and Figs. 10 and 12, depicts the line above which the system becomes economically viable.

5.4.2. *Oxygen Selling Price*

Oxygen prices are also subject to market forces and cannot be predicted in a reliable manner; thus, the impact of oxygen prices varying from 0.05 to 0.3 CAD/Nm^3 is investigated here. The resulting profits and electrolyzer utilizations are presented in Fig. 9, and the corresponding MIRR factors in Fig. 10. Observe from the latter figure that the system is economically acceptable for all oxygen prices, since the MIRR is always above the 10% threshold; the same conclusion can be reached from the results in Table II.

5.4.3. *Efficiencies*

Possible technical advances of electrolyzers and fuel cells are investigated in this section, where electrolyzer hydrogen efficiencies were varied from 60% to 90%, simultaneously with fuel cell efficiencies, changing from 45% to 60%. From these studies it was concluded that the increase of efficiencies of fuel cells has negligible impact on the profits and MIRR indices shown in Figs. 11 and 12. Therefore, only the sensitivity of electrolyzer efficiencies is represented on these figures, since these figures are not affected by variations in fuel cell efficiencies. The results depicted in these figures clearly show that the system economics are favorable for the whole range of electrolyzer hydrogen efficiencies considered.

6. CONCLUSIONS

The feasibility of hydrogen storage for a mixed wind-nuclear power plant with option of direct hydrogen selling, considering utilization of residual heat and oxygen, has been studied in this article. This analysis has been completed in the context of an envisioned ‘Hydrogen Economy’. The presented studies for a realistic wind-nuclear-hydrogen systems located in Bruce County, Canada, shows that the system is economically feasible with high rates of returns, and that profitability is considerably higher when heat and oxygen are utilized. The results further show that stationary fuel cells for electricity generation in this system are not justifiable in the price range considered; thus, the hydrogen system is mainly used for production of hydrogen for use in transportation and industrial markets rather than for electricity storage. A different system setup may lead to different conclusions; for example, significantly higher and volatile electricity prices might likely lead to a higher utilization of the stationery fuel cells, which are studies currently being performed.

7. ACKNOWLEDGEMENTS

This work was supported by Bruce Power, Ontario Centre of Excellence (OCE), National Sciences and Engineering Research Council of Canada (NSERC) and Ad Futura, which the authors gratefully acknowledge.

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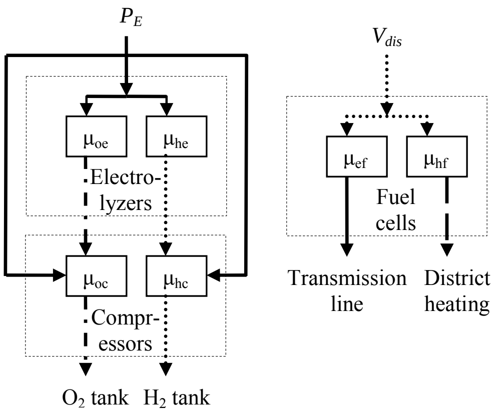

Fig. 1: Detailed electrolyzer model with compressors and stationary fuel cell model (- electricity flow, ·- oxygen flow, ·· hydrogen flow).

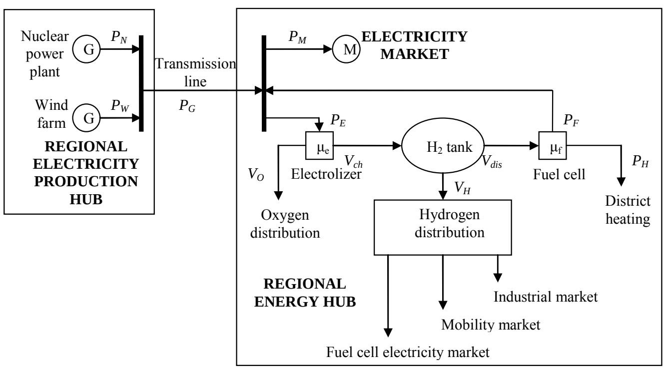

Fig. 2: Structure of a "regional energy hub" including hydrogen as an energy storage medium.

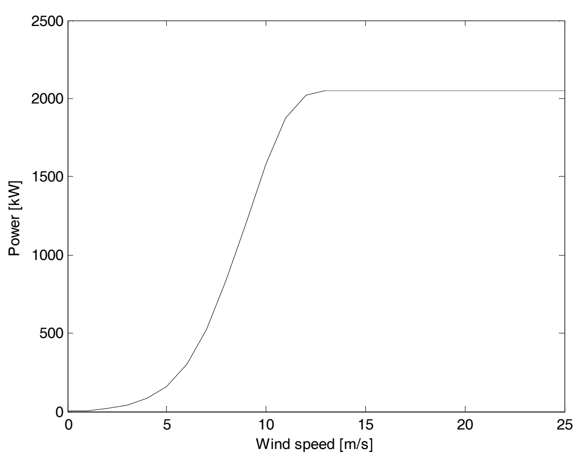

Fig. 3: The Enercon E82 wind turbine input/output characteristics.

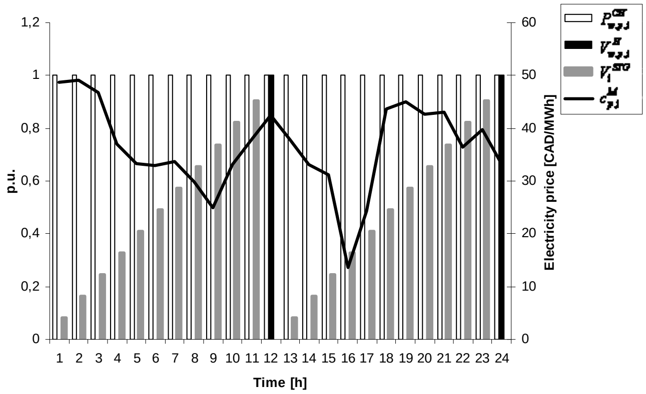

Fig. 4: Electrolyzer operation, hydrogen selling and actual electricity prices for a typical day (Day 1).

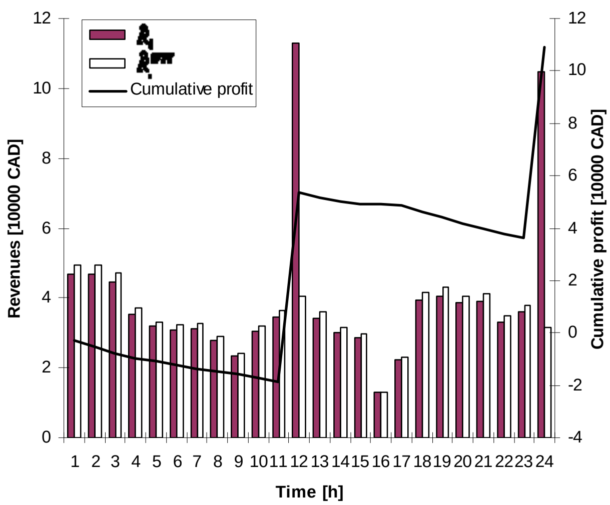

Fig. 5: The revenues with and without hydrogen storage system and the resulting cumulative profit for a typical day (Day 1).

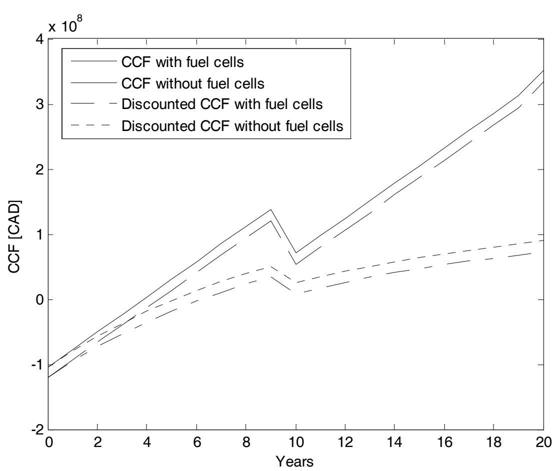

Fig. 6: Nominal and discounted cumulative cash flows for the scenarios with and without stationary fuel cells.

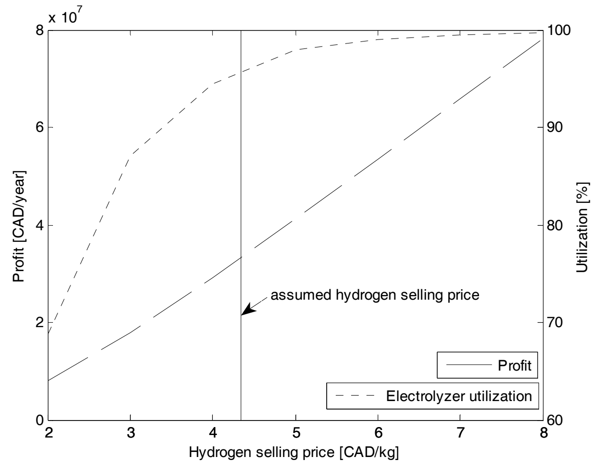

Fig. 7: Profit and electrolyzer utilization with respect to hydrogen selling prices.

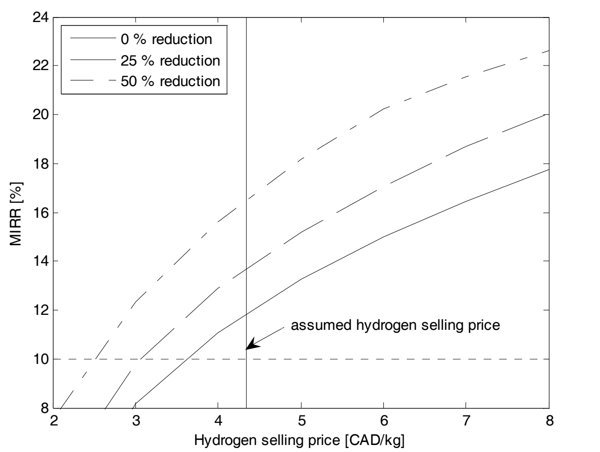

Fig. 8: MIRR with respect to hydrogen selling prices.

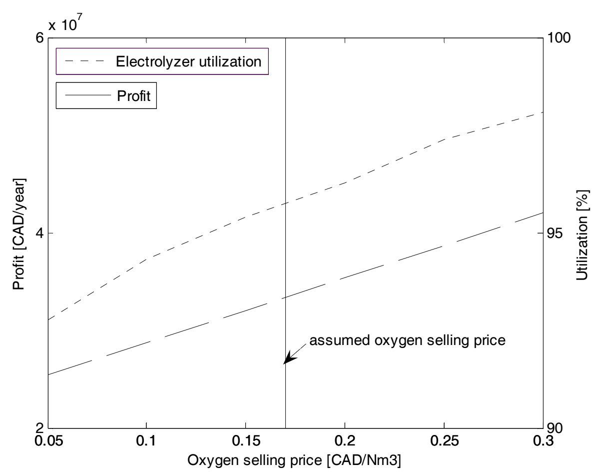

Fig. 9: Profit and electrolyzer utilization with respect to oxygen selling prices.

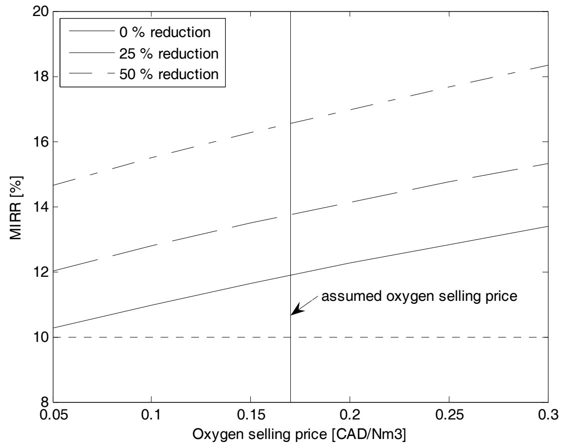

Fig. 10: MIRR with respect to oxygen selling prices.

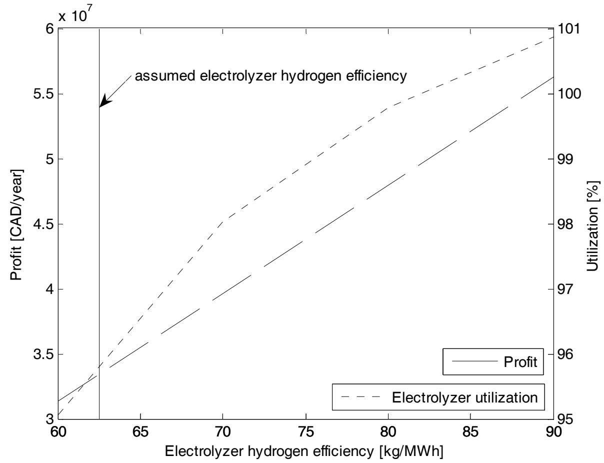

Fig. 11: Profit and electrolyzer utilization with respect to electrolyzer hydrogen efficiency.

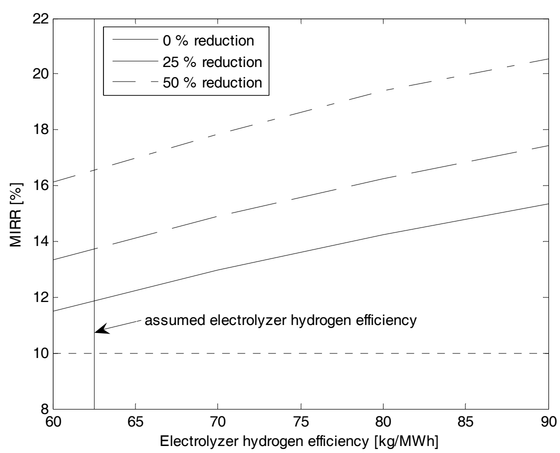

Fig. 12: MIRR with respect to electrolyzer hydrogen efficiency.

TABLE I: SYSTEM PARAMETERS

PARAMETER	ELECTROLYZER	COMPRESSOR	STORAGE	FUEL CELL
Number	264	2	28	322
Price (CAD per module)	413,985	2'560,121	881,353	65,000
Lifetime (years)	10	20	20	20
Max. capacity	0.288 (MW/module)	1661 (kg/h per module-Hydrogen) 9250 (Nm^3/h per module Oxygen)	1240 (kg/module at 6000psi)	0.065 (MW/module)
Min. capacity (MW/module)	0.072	—	—	0.065
Hydrogen efficiency (kg/MWh)	18.728867	449	—	68.09925
Oxygen efficiency (Nm^3/MWh)	104.16	2500	—	—
Thermal efficiency (kg/MWh)	—	—	—	76.92

TABLE II: RESULTS FOR SCENARIO WITHOUT OXYGEN AND HEAT UTILIZATION, WITH AND WITHOUT FUEL CELLS AND FORECASTING ERRORS

FACTOR	FC/FE	NFC/FE	FC/NFE	NFC/NFE
Profit [CAD/year]	23’337,244	23’322,249	23’337,279	23’322,249
NPV [CAD]	15’364,582	32’208,755	15’364,827	32’208,755
MIRR [%]	10.16	10.81	10.16	10.81
Fuel cell utililization [%]	0.034	0	0.046	0
Electrolyzer utililization [%]	92.18	92.18	92.19	92.18
Investment costs [CAD]	108’840,827	93’143,327	108’840,827	93’143,327
O&M costs [CAD/year]	2’902,422	2’483,822	2’902,422	2’483,822

TABLE III: RESULTS FOR BASE CASE SCENARIO WITH AND WITHOUT FUEL CELLS AND FORECASTING ERRORS

FACTOR	FC/FE	NFC/FE	FC/NFE	NFC/NFE
Profit [CAD/year]	33’339,928	33’321,487	33’339,929	33’321,487
NPV [CAD]	73’319,350	90’139,405	73’319,357	90’139,405
MIRR [%]	11.90	12.53	11.90	12.53
Fuel cell utililization [%]	0.057	0	0.057	0
Electrolyzer utililization [%]	95.80	95.80	95.80	95.80
Investment costs [CAD]	120’015,124	104’317,624	120’015,124	104’317,624
O&M costs [CAD/year]	3’200,403	2’781,803	3’200,403	2’781,803