# THE FEASIBILITY OF HYDROGEN STORAGE FOR MIXED WIND-NUCLEAR POWER PLANTS

G. Taljan, *Student Member, IEEE*, C. Cañizares, *Fellow, IEEE,* M. Fowler, G. Verbič, *Member, IEEE*

***Abstract*—A novel methodology for economic evaluation of hydrogen storage for a mixed wind-nuclear power plant is presented in this article in a context of a "Hydrogen Economy". The simulation of the operation of the combined nuclear-wind-hydrogen system is discussed first, where the selling and buying of electricity and the selling of excess hydrogen and oxygen is optimized to maximize profits. This simulation is done in two phases: In the pre-dispatch phase, the system operation is optimized according to stochastic wind and price forecasts to obtain optimal hydrogen charge levels for the operational horizon. In the second phase, a real-time dispatch is carried out on an hourly basis to optimize the operation of the system to maximize profits, and to follow the 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. The results of these studies demonstrate that hydrogen for the sole purpose of storage of electricity is not economically feasible at the current state of hydrogen technology development, unless hydrogen is sold to the market for other purposes such as transportation, as in the case in a Hydrogen Economy, or in the case of limited electricity transmission capacities, i.e. transmission congestion.**

***Index Terms*—wind power, nuclear power, hydrogen storage, Hydrogen Economy, power generation planning, optimization, investment evaluation.**

## I. Nomenclature

### A. Parameters and constraints

$\mu_c$ : hydrogen efficiency of electrolyzer (kg/MWh)

$\mu_d$ : hydrogen efficiency of fuel cell (kg/MWh)

$\mu_O$ : oxygen efficiency of electrolyzer (Nm$^3$/MWh)

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

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

Accepted for publication in *IEEE Trans. Power Systems*, Feb. 2008.

This work was supported by Bruce Power, Ontario Centres of Excellence (OCE), NSERC and Ad Futura.

G. Taljan and G. Verbič are with University of Ljubljana, Faculty of electrical engineering, Ljubljana, Slovenia (e-mail: gregor.taljan@fe.uni-lj.si, gregor.verbic@fe.uni-lj.si).

C. Canizares and M. Fowler are with University of Waterloo, Waterloo, Canada (e-mail: ccanizar@uwaterloo.ca, mfowler@cape.uwaterloo.ca).

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

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

$P_{\max}^{STGDISCH}$ : maximum fuel cell power (MW)

$P_{\min}^{STGDISCH}$ : minimum fuel cell power (MW)

$P_{\max}^{STGCHAR}$ : maximum electrolyzer power (MW)

$P_{\min}^{STGCHAR}$ : minimum electrolyzer power (MW)

$c_{\min}$ : minimal bid price at the Ontario electricity market (CAD/MWh)

$N_w$ : number of wind scenarios

$N_p$ : number of price scenarios

$T$ : number of time steps

### B. Variables

$P_W$ : wind power plant production (MW)

$P_N$ : nuclear power plant production (MW)

$P_C$ : electrolyzer consumption (MW)

$P_D$ : fuel cell production (MW)

$P_M$ : power exchange with the market (MW)

$V_{charge}$ : electrolyzer hydrogen production (kg)

$V_{discharge}$ : fuel cells hydrogen consumption (kg)

$V_{hsell}$ : hydrogen exchange with the market (kg)

$P_{w,p,i}^{WIND}$ : wind-nuclear power consumed for wind scenario *w* and price scenario p in hour *i* (MW)

$P_{w,p,i}^{STGCHAR}$ : electrolyzer electricity consumption for wind scenario *w* and price scenario *p* in hour *i* (MW)

$P_{w,p,i}^{STGDISCH}$ : fuel cell electricity production for wind scenario *w* and price scenario *p* in hour *i* (MW)

$V_i^{STG}$ : hydrogen storage level in hour *i* (kg)

$V_{w,p,i}^{HSELL}$ : hydrogen exchange with the market in wind scenario *w* and price scenario *p* in hour *i* (kg)

$V_{w,p,i}^{OSELL}$ : oxygen production in wind scenario *w* and price scenario $p$ in hour $i$ ($Nm^3$)

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

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

$\hat{P}_i^{WIND}$ : actual wind-nuclear power used in hour $i$ (MW)

$\hat{P}_i^{STGCHAR}$ : actual electrolyzer electricity consumption in hour $i$ (MW)

$\hat{P}_i^{STGDISCH}$ : actual fuel cell electricity production in hour $i$ (MW)

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

$\hat{V}_i^{HSELL}$ : actual hydrogen exchange with the market in hour $i$ (kg)

$\hat{V}_i^{OSELL}$ : actual oxygen production in hour $i$ ($Nm^3$)

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

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

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

$\hat{R}_i$ : revenues from hydrogen subsystem in hour $i$ (CAD)

$\hat{R}_i^{WH}$ : revenues without hydrogen subsystem in hour $i$ (CAD)

### C. Input data

$p_w$ : probability of wind scenario $w$

$p_p$ : probability of price scenario $p$

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

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

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

$\hat{W}_i$ : actual wind-nuclear generation n hour $i$ (MW)

## II. Introduction

THERE is a growing concern about the negative environmental impacts associated with the use of fossil energy sources (FES) in particular global warming impacts. In this context, some of the main real emission-free and sustainable options for FES in electricity generation are nuclear and renewable energy sources (RES) [1]. Nuclear technology is already well developed and is a significant part of the energy mix in several jurisdictions around the world (e.g. France, Ontario). RES, on the other hand, are still at the development stage; however, some technologies, especially wind, are already taking a considerable part of the energy mix in several markets (e.g. Denmark, Germany).

With respect to transportation, there is still a lack of an energy carrier that would replace FES as an efficient and feasible storage option. In this context, the concept of a Hydrogen Economy, which is a hypothetical economy where energy is stored and carried as hydrogen ($H_2$), has been proposed [2]. Various Hydrogen Economy scenarios can be envisaged, using hydrogen in a number of different ways; a common feature of these scenarios is the use of hydrogen as an energy carrier for mobility applications (e.g. cars, rail, aircrafts) as well as electricity generation. Thus, the generation, storage and usage of hydrogen have recently gained significant attention.

There has been some research carried out investigating different hydrogen production and usage options. The possible use of nuclear power plants for the sole purpose of production of hydrogen through novel thermo-chemical cycles and high temperature electrolysis, as discussed in [3], show that those technologies will enable production of hydrogen at efficiencies as high as 50-60%, instead of less than 30% efficiency with conventional electrolysis; this will result in lowering the costs of hydrogen production. In [4], the technical and financial feasibility of hydrogen as an energy carrier is presented for a stand-alone application of RES in Australia; the results show that electricity produced by such system is more expensive than the electricity for domestic customers connected to the grid (2.52 AUD/kWh compared to 0.13 AUD/kWh). It is further shown in [5], that hydrogen storage is not yet fully competitive compared to battery storage due to its low round-trip efficiency (about 0.37% presented in the article), and high investments, operation and maintenance (O&M) costs. The two latter studies are only limited to electricity storage capabilities of hydrogen and do not include other possible applications of hydrogen, within the context of a Hydrogen Economy, such as its possible use in the transportation sector.

There has also been some research done in the field of optimal generation scheduling with electricity storage. In [6], the optimal operation of hydrogen storage together with intermittent RES on the European electricity markets is discussed. The results suggest that hydrogen storage with intermittent RES, such as wind, can considerably increase the income of the producer, and byproducts of electrolysis and fuel cell usage, such as oxygen and heat, might improve the hydrogen system economic performance. However, a comprehensive economic analysis considering the investment and O&M costs of such a system is missing in this article. In [7], the economics of nuclear power for electrolytic hydrogen production in the context of the electricity market in Alberta, Canada, is analyzed. The results are compared with common steam-methane-reforming (SMR) hydrogen production processes, with costs assumptions for the hydrogen subsystem being relatively low and without considering an adequate system operation optimization.

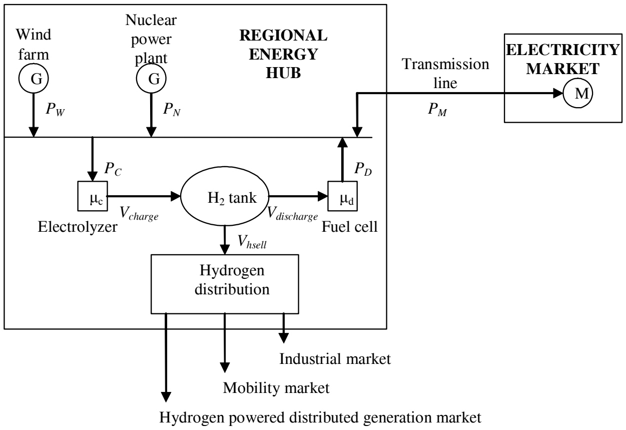


Fig. 1: Structure of a "regional energy hub" including hydrogen as energy storage and energy carrier. The notation used is detailed in Section I.

The paper results show that hydrogen production is a favorable option; however, a proper sensitivity analysis of possible investment scenarios is missing. The present paper tries to broaden these studies by considering realistic hydrogen production costs as well as uncertainties, and performing various sensitivity analyses. Thus, it tries to answer the question of whether the use of hydrogen for energy storage in a mixed wind-nuclear generation plant, considering hydrogen production within the context of a Hydrogen Economy, is economically justifiable. A variety of system optimization models and studies are performed, using various economic indices such as internal rate of return and net present value to evaluate the feasibility and worth of the proposed integrated Nuclear-Wind-Hydrogen system.

The rest of the paper is structured as follows. In Section III, the proposed models and analysis methods 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 conclusions of the presented studies are summarized in Section VI.

## III. Simulation Methodology

The proposed system consists of a nuclear power plant (NPP) and a wind farm selling electricity in the Ontario electricity market, which is a realistic scenario being currently faced by the Bruce Power company. The system includes hydrogen storage and distribution facilities according to the model depicted in Fig. 1. Hydrogen generation and storage is considered for the following potential benefits:

- Part of the electricity production can be stored as hydrogen in periods of low electricity prices and then sold to the electricity market at high-price periods.
- When there is not enough line capacity to sell the whole electricity production to the market, the excess electricity may be stored as hydrogen and then sold to the market when there is sufficient line capacity.
- Hydrogen may be sold directly to a hydrogen market when the price of hydrogen is greater than the costs of producing it, and/or when profit is higher than selling it into the electricity market.
- Hydrogen within the hub can be used as a storage mechanism to relieve some of the electrical grid operational challenges associated with the variability of wind generation, in particular power dispatch and frequency control.

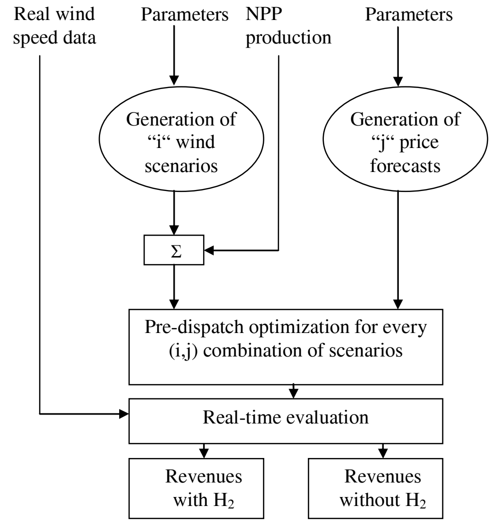


Fig. 2: System operation procedures.

The system operation and market bidding, for the system depicted in Fig. 1, is optimized based on a mixed integer stochastic linear programming (MISLP) model. In this model, wind production and electricity prices are the stochastic input parameters, and the option of selling $O_2$ and $H_2$ is also considered. The flowchart of the system operation and bidding processes used for the studies presented here is shown in Fig. 2.

Several articles about bidding of electricity from intermittent energy sources and considering price forecasts in European electricity markets are available (e.g. [8], [9]); these articles use stochastic programming techniques to incorporate the stochastic variables such as price and wind forecasts in the optimization process. In [8], the objective function is the minimization of imbalance costs due to deviations of wind production from bids to the market. In [9], a similar methodology is used to incorporate the electricity storage in form of pumped-storage units in the optimization process in day-ahead European electricity markets, with a balancing market for deviations of actual productions from bids. A novel approach is presented here for the Ontario electricity market, based on the models proposed in [8] and [9]. A two-level study approach is used; thus, dispatch levels are first obtained one-day ahead based on a stochastic optimization model, and 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 real-time operation results.

## A. Pre-dispatch

The following optimization model for obtaining one-day ahead dispatch levels considers that the only variable that links operating hours and days together is the storage content; hence, the storage content variable is fixed in this model, making it time dependent but not scenario dependent, as it can be seen from the definition of the storage content variable:

$$\max \sum_{w=1}^{Nw} p_w \cdot \sum_{p=1}^{Np} p_p \cdot \sum_{i=1}^{T} (c_{p,i}^{M}(P_{w,p,i}^{WIND} + P_{w,p,i}^{STGDISCH} - P_{w,p,i}^{STGCHAR}) + c^{H} V_{w,p,i}^{HSELL} + c^{O} V_{w,p,i}^{OSELL}) \quad (1)$$

s.t.

$$-P_{\max}^{NET} \le P_{w,p,i}^{WIND} + P_{w,p,i}^{STGDISCH} - P_{w,p,i}^{STGCHAR} \le P_{\max}^{NET} \quad (2)$$

$$0 \le P_{w,p,i}^{WIND} \le W_{w,i} \quad (3)$$

$$V_i^{STG} = V_{i-1}^{STG} + \mu_c P_{w,p,i}^{STGCHAR} - \mu_d P_{w,p,i}^{STGDISCH} - V_{w,p,i}^{HSELL} \quad (4)$$

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

$$\alpha_{w,p,i} \cdot P_{\min}^{STGDISCH} \le P_{w,p,i}^{STGDISCH} \le \alpha_{w,p,i} \cdot P_{\max}^{STGDISCH} \quad (6)$$

$$\beta_{w,p,i} \cdot P_{\min}^{STGCHAR} \le P_{w,p,i}^{STGCHAR} \le \beta_{w,p,i} \cdot P_{\max}^{STGCHAR} \quad (7)$$

$$0 \le V_i^{STG} \le V_{\max}^{STG} \quad (8)$$

$$V_{w,p,i}^{OSELL} = \mu_O P_{w,p,i}^{STGCHAR} \quad (9)$$

All variables above are properly defined in Section I. In this model, $c_{p,i}^{M}$ and $W_{w,p,i}$ are stochastic parameters, with $c_{p,i}^{M}$ representing the electricity price at the location being considered, which in markets based on locational marginal pricing it would be affected by line congestion; however, for the case studied here, which is located in Ontario, a uniform price market, this price is not considered to be affected by line congestion. The binary variables $\alpha_{w,p,i}$ and $\beta_{w,p,i}$ for on/off modeling of the electrolyzer and fuel cells in equations (6) and (7) make this model a mixed integer stochastic linear programming (MISLP) model. The production and consumption limits of the model are defined by the line capacities in equation (2). Equation (3) restricts the actual wind production depending of the wind forecast $w$ at hour $i$. Equations (4)-(8) model the operation of the hydrogen subsystem. Finally, equation (9) describes the production of oxygen depending on electrolyzer utilization. The optimization function considers only a limited operation horizon of one day, with hourly resolution and no start up time for electrolyzers. Two consecutive operation periods are linked via the hydrogen storage content equation (4) at the end of the first period. Finally, observe that the model considers the simultaneous production and consumption of hydrogen, since, as per Fig. 1, there is a hydrogen demand from a market driven by Hydrogen Economy considerations, with hydrogen being sold for transportation applications, i.e. the hydrogen system is not only used to simply "store electricity."

The forecasting horizon is set to 24 h, since a longer horizon would not improve the overall performance of the system, since the forecasting error of electricity prices and wind speeds increase with forecasting length [8], limiting the ability to properly asses the optimal operation of the system. On the other hand, a shorter pre-dispatch optimization horizon would mean only increased number of local optimums, without having the ability to make use of all the wind power and price fluctuations.

## B. Real-time Dispatch

A simple real-time operating strategy that follows the scheduled hydrogen storage obtained from the solution of the MILSP problem (1)-(9) is used. The excess hydrogen is sold as electricity from stationery fuel cells or to a hydrogen market to maximize profits. The optimization is done on an hourly basis. The constraints are the same as in the previously described optimization model. Thus, the real-time dispatch problem is modeled as a mixed-integer linear programming (MILP) optimization problem as follows, with all variables being defined in Section I:

$$\max \quad (\hat{c}_i^{M}(\hat{P}_i^{WIND} + \hat{P}_i^{STGDISCH} - \hat{P}_i^{STGCHAR}) + \hat{c}^{H} \hat{V}_i^{HSELL} + c^{O} \hat{V}_i^{OSELL}) \quad (10)$$

s.t.

$$-P_{\max}^{NET} \le \hat{P}_i^{WIND} + \hat{P}_i^{STGDISCH} - \hat{P}_i^{STGCHAR} \le P_{\max}^{NET} \quad (11)$$

$$0 \le \hat{P}_i^{WIND} \le \hat{W}_i \quad (12)$$

$$\hat{V}_i^{STG} = \hat{V}_{i-1}^{STG} + \mu_c \hat{P}_i^{STGCHAR} - \mu_d \hat{P}_w^{STGDISCH} - \hat{V}_i^{HSELL} \quad (13)$$

$$\hat{V}_1^{STG} = V_i^{STG} \quad (14)$$

$$\hat{V}_0^{STG} = \hat{V}_{d-1}^{STGEND} \quad (15)$$

$$\hat{\alpha}_i \cdot P_{\min}^{STGDISCH} \le \hat{P}_i^{STGDISCH} \le \hat{\alpha}_i \cdot P_{\max}^{STGDISCH} \quad (16)$$

$$\hat{\beta}_i \cdot P_{\min}^{STGCHAR} \le \hat{P}_i^{STGCHAR} \le \hat{\beta}_i \cdot P_{\max}^{STGCHAR} \quad (17)$$

$$0 \le \hat{V}_i^{STG} \le V_{\max}^{STG} \quad (18)$$

$$\hat{V}_i^{OSELL} = \mu_O \hat{P}_i^{STGCHAR} \quad (19)$$

$$\hat{V}_d^{STGEND} = \hat{V}_T^{STG} \quad (20)$$

Observe that this model is very similar to the pre-dispatch model (1)-(9); however, in this case, there are no stochastic parameters and the optimization model corresponds to one-hour only, which is solved on an hourly basis for 24 h.

### C. Economic Evaluation

The economic evaluation of projects is based on the calculation of one or more numerical indices which bear the information about the economical viability of a project. The net present value (NPV) and the internal rate of return (IRR) are indices most commonly used in the industry [10]. The NPV is the sum of the discounted cash flows during the lifetime of the project, and the IRR is the marginal discount rate for which the NPV is zero [11]. The components which are taken into account when calculating the cash flow in this article are the following: initial investment costs including transportation and installation; replacement investment costs (for replacements of worn-down assets); O&M costs; revenues; depreciation (amortization); taxes; and salvage value. It is assumed that the cash flow is already expressed in nominal monetary units with respect to the time of evaluation of the first project cash flow, so that the inflation rates are taken into consideration. The income or profit obtained from the hydrogen subsystem is the difference between total income of the wind-nuclear system with hydrogen and without hydrogen, where the income with hydrogen system is calculated using:

$$\hat{R}_i = (\hat{c}_i^M (\hat{P}_i^{WIND} + \hat{P}_i^{STGDISCH} - \hat{P}_i^{STGCHAR}) + c^H \hat{V}_i^{HSELL} + c^O \hat{V}_i^{OSELL}) \tag{21}$$

The income without fuel cells is calculated using the following equation:

$$\hat{R}_i^{WH} = \hat{c}_i^M \cdot \min(P_{\max}^{NET}, \hat{P}_i^{WIND}) \tag{22}$$

## IV. Actual System Setup

The system is assumed to be located in Bruce County in Ontario, Canada. This location was chosen because of Bruce Power's NPP currently operating in the region, together with a growing wind capacity in the region such as Huron Wind's wind farm. Any investment or O&M costs associated with existing units are disregarded in the economic analysis, since these units are already operational, regardless of whether the hydrogen storage option is considered. All location-specific parameters are considered to be those for Ontario; thus, the chosen currency is Canadian dollars (CAD), which is converted from US dollars (USD) at a rate of 1 USD per 1.04923 CAD. From some initial studies, it was observed that the number of wind scenarios did not impact the operation of the system, due to sufficient capacity of the transmission network and the fact that the energy production from Bruce Power's NPP is sufficient to run the electrolyzers; hence, only one wind scenario is considered here in the optimization procedure. Even in the case of insufficient line capacity, wind forecasts will not impact system profitability due to the observed low fuel cell utilization. This assumption is further justified based on the results presented and discussed in Section V.

To represent the stochastic price behavior, 30 price scenarios are generated for each optimization period, which is considered to be 24 h with hourly resolution. 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 discount rate used in the calculations of the NPV is 8%, as per typical values ranging from 5% to 10% [10].

There are two governmental/provincial tax rates in Canada depending on yearly income. For incomes less than 300,000 CAD, an 18.62% tax rate applies, and for incomes above this figure a 34.12% tax rate is used. 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 [12]. 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 [12], is assumed to cover 25% of the initial investment costs; this support does not include replacement costs for worn-down equipment after its lifetime. The uniformed salvage value of equipment at the end of its lifetime is assumed to be 10% of the investment costs [13]. The operation and maintenance costs are assumed to be 2% per year of initial investment [13].

### A. Ontario Electricity Market

The model was developed considering the Ontario electricity market rules [14], [15], [16]. Hence, the following assumptions for the developed models are based on a NPP and a wind farm operating in Ontario:

- The producer is a price taker in the electricity market, due to the relatively small scale of the hydrogen facilities.
- The market bids are $c_{min}$=-2000 CAD/MWh, so that the units are always dispatched. The NPP production is added to the wind-power production, and the aggregated production is used as an input to the model.
- The NPP production is greater than the maximum electrolyzer demand; thus, there is always enough electricity to feed the electrolyzer.
- For real-time operation, the wind farm is considered as an intermittent generator according to [15]. Intermittent generators supply the Independent Electricity System Operator (IESO) with production forecasts, but are not obliged to actually deliver the forecasted power, and do not have to follow the IESO's dispatch instructions. These types of generators may not register for the provision of any physical service, other than energy and reactive support and voltage control services.
- Qualifying large-scale wind energy generation projects are also eligible for a Wind Power Production Incentive [12]. An initial incentive payment of 12 CAD/MWh of production, gradually declining to 8 CAD/MWh, is available for the first ten years of production.

TABLE I: ELECTROLYZER PARAMETERS

| PARAMETER | VALUE |
|---|---|
| Number | 32 |
| Price (CAD per module) | 480463 |
| Lifetime (years) | 10 |
| Max. capacity (MW/module) | 0.288 |
| Min. capacity (MW/module) | 0.072 |
| Hydrogen efficiency (kg/MWh) | 18.7 |
| Oxygen efficiency ($Nm^3$/MWh) | 119 |

TABLE II: COMPRESSOR PARAMETERS

| PARAMETER | VALUE |
|---|---|
| Number | 40 |
| Price (CAD per module) | 81523 |
| Lifetime (years) | 20 |
| Capacity ($Nm^3$/h) | 48 |

TABLE III: STORAGE PARAMETERS

| PARAMETER | VALUE |
|---|---|
| Number | 101 |
| Price (CAD per module) | 22033 |
| Lifetime (years) | 20 |
| Max. capacity (kg/module at 400 bars) | 20.62 |
| Initial hydrogen in tank (kg) | 0 |

TABLE IV: FUEL CELL PARAMETERS

| PARAMETER | VALUE |
|---|---|
| Number | 141 |
| Price (CAD per module) | 195000 |
| Lifetime (years) | 20 |
| Max. capacity (MW/module) | 0.065 |
| Min. capacity (MW/module) | 0.065 |
| Hydrogen efficiency (kg/MWh) | 68.1 |

### *B. Wind Subsystem*

Huron Wind is Ontario's first commercial wind farm, and is located on the shore of Lake Huron in Bruce County, Ontario. The site is seven kilometers northwest of Tiverton in the municipality of Kincardine. The wind farm consists of five Vestas V80 1.8 MW wind turbines, which gives a total output power of 9 MW [17]. The wind speeds for 2005 were obtained from the design proposal for renewable energy generation facilities in Kincardine [13].

### *C. Nuclear Subsystem*

Bruce Power is Canada's first private nuclear generating company, and the source of more than 20% of Ontario's electricity. It is located approximately 250 km northwest of Toronto and currently operates six reactor units, with installed capacity of 4820 MW. 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 [18], which gives them a capacity factor of 82%, equal to 3952.4 MW of constant electricity production. It is assumed that 3000 MW of constant electricity is sold to the IESO on a bilateral contract, and the remaining 952.4 MW capacity is bid into the electricity market or may be converted to hydrogen.

### *D. Transmission Line Capacity*

A simplified model of the line capacity is used here, which is an adequate approximation for the purpose of the present feasibility study. Thus, transmission capacity limits are represented through the use of $P_{\max}^{NET}$ in equations (2) and (11) of the pre-dispatch and dispatch models, respectively. Observe that if the wind power plant were located afar from the NPP, to generalize the proposed optimization models, the transmission line limits could be readily included into the model by simply separating the power limits on the output of the wind, nuclear and hydrogen subsystems instead of representing them in the proposed aggregated manner. Furthermore, note that the transmission line capacity model can be readily changed to accommodate hourly changes in transmission capacity; this can be accomplished by replacing $P_{\max}^{NET}$ by $P_{\max,i}^{NET}$ in equations (2) and (11). Finally, it should be mentioned that the transmission losses are not considered in the model since this is a particular transmission system issue under the purview of the system operator (Ontario's IESO in this case), and is handled centrally and independently from the power producers, based on mechanisms such as system balancing services and/or network charges, which do not have a significant influence on the proposed models, analysis methodologies and results.

For the particular case study discussed here, the majority of the power is transmitted via the 500 kV Bruce-Milton line with total capacity of 5000 MW, running from the Bruce area to the load centre in the eastern part of Ontario around Toronto. In principle, there is abundant line capacity according to the IESO data, and hence thermal, voltage and other IESO managed constraints should not impact the system operation and profitability. This assumption can be further justified by considering the relatively low installed capacity of hydrogen subsystem, which leads to the free line capacity being lower than the fuel cell capacity for only 17 hours a year in 2006, for example. Finally, the refurbishment of Bruce A reactors 1 and 2 will add an additional 1500 MW of installed capacity in 2010-2011; however, this should not impact the system operation and revenues, as it will be accompanied by an expansion of the Bruce-Milton transmission line. In spite of these observations, congestion of the Bruce-Milton transmission corridor is still studied in this paper, as discussed in detail in Section V-C.

### *E. Hydrogen Subsystem*

The hydrogen subsystem is dimensioned to have the same capacity as the wind subsystem. The NPP is assumed to provide required electricity in periods of low electricity production from wind. The test system is comprised of 32 Hydrogenics HySTAT-A IMET 1000 Electrolyzers [19], with total installed power of 9.216 MW and a maximum production rate of hydrogen of 1920 $Nm^3/h$. Because the prices of equipment are confidential, the prices reported in [20] were used here. Thus, electrolyzer prices are assumed to vary from 1370 USD/kW to 3693 USD/kW, depending on installed power and economies of scale; hence, a price of 1590 USD/kW (1668.2757 CAD/kW), assuming a large-scale economy and medium sized units, was used here. All electrolyzer parameters are listed in Table I. A hydrogen efficiency of 4.8 $kWh/Nm^3$ or 18.728867 kg/MWh was considered according to [19]; this figure represents the amount of hydrogen produced by 1 MWh of electricity, and results in an efficiency of 62.5%, including rectifier and auxiliaries, and considering the energy value of 1 kg of hydrogen to be equal to 33.33 kWh [2].

Hydrogen production is considered here to be solely from traditional and commercially available electrolysis processes, since the use of thermo-chemical processes for hydrogen production would require the replacement of the existent nuclear reactors, as this is not technically feasible with current low-temperature Canadian nuclear technology. Nevertheless, observe that the proposed optimization models could be in principle modified to consider this possibility; in this case, different conversion efficiencies and associated parameters would have to be considered accordingly.

A compressor array comprised of 40 PPI 3 stage metal diaphragm compressors [21], with total capacity of 1920 $Nm^3/h$, is assumed to be used to compress the hydrogen to 400 bar (6000 psig), which is the storage pressure of the storage tanks, allowing the distribution to the hydrogen market. The efficiency of the compressors is assumed to be practically 100%. Prices for compressors vary from 10000 USD/kg/h (900 $USD/Nm^3/h$) to 27142 USD/kg/h (2440 $USD/Nm^3/h$) for this size diaphragm compressors [20]. A medium price of 18000 USD/kg/h was chosen here, which is equal to 18886 CAD/kg/h (1698 $CAD/Nm^3/h$). All compressor parameters are listed in Table II.

The hydrogen storage consists of 101 hydrogen storage vessels, assumed to be provided by CP Industries, with total capacity of 2082.62 kg of hydrogen at 400 bars. This provides enough storage to store the hydrogen produced in 12 consecutive hours. This size was chosen on the assumption that the system will be optimized in 24 h intervals, and that peak prices are reached in the afternoon. The price of one CPI tank is 21000 USD (22033 CAD), according to the producer information. The storage parameters are shown in Table III.

The stationery fuel cell array includes 141 Hydrogenics HyPM 500 series fuel cells of 65 kW each; this adds up to 9.165 MW of total installed capacity for the entire array. The technical parameters are depicted in Table IV, as per reference [22]. Prices are confidential and vary in the literature. In [20], the price range stated is 297 USD/kW-8965 USD/kW. In [23], the lowest price is 3000 USD/kW, which seems to be reasonable from the discussions in [20], and is hence used here. The minimum capacity of the array is equal to the maximum capacity of a single fuel cell power module. The hydrogen efficiency of the fuel cells in Table IV represents the amount of hydrogen needed to produce 1 MW of electricity; hence, the overall fuel cell efficiency is 44%, which gives a "round-trip efficiency" (i.e. generation of electricity from hydrogen and then use of hydrogen to produce electricity) of 27.50%. Observe that this means that the selling price of electricity should be about four times the buying electricity price for the hydrogen subsystem to be able to profit from the storing of electricity.

The total initial investment costs are 5238 CAD per kW of installed capacity. The hydrogen selling price is taken as bulk hydrogen price produced from natural gas in 2020, which is half of the assumed lifetime of the system. Natural gas is currently the primary energy source for production of hydrogen as well as the lowest cost source, [23]; therefore, it is assumed that the prices of hydrogen will be mostly dependant on natural gas prices in the system's life-time. The bulk pre-tax price of hydrogen for different natural gas prices is reported in [23]; if natural gas prices vary between 3.5-15 USD/GJ, the hydrogen prices vary between 1.8-4.1 USD/kg for a 22 tons/day hydrogen production plant. Since nominal gas price forecasts in [24] for 2015-2030 are 7.62-12.24 USD/MBtu, the price at 2020 is assumed to be 9.16 USD/MBtu, which is equal to 8.68 USD/GJ. Hence, according to this price of gas, the hydrogen production price is assumed here to be 2.74 USD/kg. If a carbon tax of 0.35 USD/kg is added as in [23], the converted end-price is 3.24 CAD/kg. If Canadian and Ontario tax rates of 34.12% are added, the wholesale hydrogen price becomes 4.35 CAD/kg.

Hydrogen transportation costs are considered "external" costs for the present studies, and are hence not factored in the hydrogen selling price. Usually, gaseous hydrogen can be transported using high-pressure cylinders, tube trailers or pipelines [25]. Compressed-gas truck delivery would be the cheapest option for the production rate considered in the present article, costing around 0.0111 CAD/kg/km for an 80 km distance, or 0.0066 CAD/kg/km for 800 km.

Because there is no ready market for the volume of oxygen produced, the oxygen price is assumed to be 0 $CAD/Nm^3$. This is a conservative assumption, since future market potential for oxygen, such as those associated with oxy-combustion processes, would improve the overall economics of the discussed system.

### *F. Electricity Price Forecasts*

A simple electricity price forecasting module was developed, assuming a normal distribution of electricity price forecasts around actual electricity prices. The price forecasts are generated here by adding random numbers from normal distribution, with mean value $\mu$ = 0 CAD, and a standard deviation of $\sigma$ = 13.8 CAD, to the hourly Ontario energy price (HOEP); the maximum relative error is limited

TABLE V: THE PRE-DISPATCH RESULTS FOR THE SIMPLE TEST CASE

| p | i | $W_{w,i}$ | $c^{M}_{p,i}$ | $P^{WIND}_{w,i}$ | $P^{STGCHAR}_{w,p,i}$ | $P^{STGDISCH}_{w,p,i}$ | $V^{HSELL}_{w,p,i}$ | $V^{STG}_{i}$ | $V^{OSELL}_{w,p,i}$ |
|---|---|---|---|---|---|---|---|---|---|
| 1 | 1 | 960.11 | 64.111 | 960.11 | 9.216 | 0 | 0 | 172.6052 | 1097.137 |
| 1 | 2 | 961.37 | 87.15 | 961.37 | 0 | 0 | 172.6052 | 0 | 0 |
| 1 | 3 | 958.38 | 69.82 | 958.38 | 9.216 | 0 | 0 | 172.6052 | 1097.137 |
| 1 | 4 | 960.77 | 78.13 | 960.77 | 9.216 | 0 | 345.2105 | 0 | 1097.137 |
| 2 | 1 | 960.11 | 75.27 | 960.11 | 9.216 | 0 | 0 | 172.6052 | 1097.137 |
| 2 | 2 | 961.37 | 90.07 | 961.37 | 0 | 0 | 172.6052 | 0 | 0 |
| 2 | 3 | 958.38 | 62.69 | 958.38 | 9.216 | 0 | 0 | 172.6052 | 1097.137 |
| 2 | 4 | 960.77 | 60.86 | 960.77 | 9.216 | 0 | 345.2105 | 0 | 1097.137 |

TABLE VI: THE REAL-TIME RESULTS FOR THE SIMPLE TEST CASE

| i | $\hat{W}_i$ | $\hat{c}^{M}_i$ | $\hat{P}^{WIND}_i$ | $\hat{P}^{STGCHAR}_i$ | $\hat{P}^{STGDISCH}_i$ | $\hat{V}^{HSELL}_i$ | $\hat{V}^{STG}_i$ | $\hat{R}_i$ | $\hat{R}^{WH}_i$ |
|---|---|---|---|---|---|---|---|---|---|
| 1 | 960.11 | 48.73 | 960.11 | 9.216 | 0 | 0 | 172.60 | 46337.43 | 46786.52 |
| 2 | 961.37 | 49.1 | 961.37 | 9.216 | 0 | 345.2104 | 0 | 48252.67 | 47203.51 |
| 3 | 958.38 | 46.7 | 958.38 | 9.216 | 0 | 0 | 172.60 | 44326.07 | 44756.46 |
| 4 | 960.77 | 37.03 | 960.77 | 9.216 | 0 | 345.2104 | 0 | 36737.75 | 35577.35 |
| | | | | | | | Total | 175653.93 | 174323.86 |
| | | | | | | | | Profit | 1330.07 |

TABLE VII: RESULTS FOR BCS CONSIDERING FC AND FE

| FACTOR | FC/FE | NFC/FE | FC/NFE | NFC/NFE |
|---|---|---|---|---|
| Profit [CAD/year] | 2’964,740 | 2’958,138 | 2’964,765 | 2’958,138 |
| NPV [CAD] | -22’087,808 | 1’755,602 | -22’087,568 | 1’755,602 |
| IRR [%] | Negative | 9.60 | Negative | 9.60 |
| Utililization FC [%] | 0.037 | 0 | 0.040 | 0 |
| Utililization EL [%] | 93.42 | 93.41 | 93.43 | 93.41 |
| Investment costs [CAD] | 36’188,811 | 15’567,561 | 36’188,811 | 15’567,561 |
| O/M costs [CAD/year] | 965,034 | 415,134 | 965,034 | 415,134 |

TABLE VIII: RESULTS FOR CONGESTION SCENARIO CONSIDERING FC AND FE

| FACTOR | FC/FE | NFC/FE | FC/NFE | NFC/NFE |
|---|---|---|---|---|
| Profit [CAD/year] | 152’534,309 | 152’534,309 | 152’534,309 | 152’534,309 |
| NPV [CAD] | 567’845,524 | 713’224,172 | 567’845,524 | 713’224,172 |
| IRR [%] | 22.21 | 32.02 | 22.21 | 32.02 |
| Utililization FC [%] | 0 | 0 | 0 | 0 |
| Utililization EL [%] | 99.86 | 99.86 | 99.86 | 99.86 |
| Investment costs [CAD] | 498’436,986 | 364’764,486 | 498’436,986 | 364’764,486 |
| O/M costs [CAD/year] | 13’291,652 | 9’727,052 | 13’291,652 | 9’727,052 |

to 30% of the HOEP. This procedure yields the same mean absolute error (MAE) as the transfer function forecasting model discussed in [14]. The electricity prices were based on HOEP values for 2005, which have a mean value of 46.38 CAD/MWh [26].

## V. RESULTS AND DISCUSSION

The simulations were performed using AMPL [27], and a CPLEX solver [28]; hence, a “Branch and Cut” approach was used to deal with the integer variables, forming sub-problems, that are then solved by a simplex optimization algorithm. The economic evaluation was all done using Matlab [29].

### A. Simple Test Scenario

To demonstrate how the pre-dispatch and real-time procedures are applied, a simple test case scenario is first used. Thus, the system described in Section IV was used, with a time horizon of 4 h and with two price forecast scenarios. The results of solving the optimization models (1)-(9) and (10)-(20) are shown in Tables V and VI. The profit made in this case due to the hydrogen subsystem utilization is 1,330 CAD. It should be highlighted, that the utilization and the resulting profits of the hydrogen subsystem are mainly dependent on three factors: electricity prices and electricity price profiles; the efficiencies of the components; and the hydrogen selling price. Investment and other costs are not a factor in this case. One can easily calculate that if there are no price forecast errors, and the hydrogen selling price is 4.35 CAD/kg, and the efficiency of the electrolyzer is 18 kg/MWh (60%), the electrolyzer would be utilized when the prices of electricity drop below 78.3 CAD/MWh. This is consistent with the results obtained in Table V, where one can observe that $P^{STGCHAR}_{w,p,i}$ is

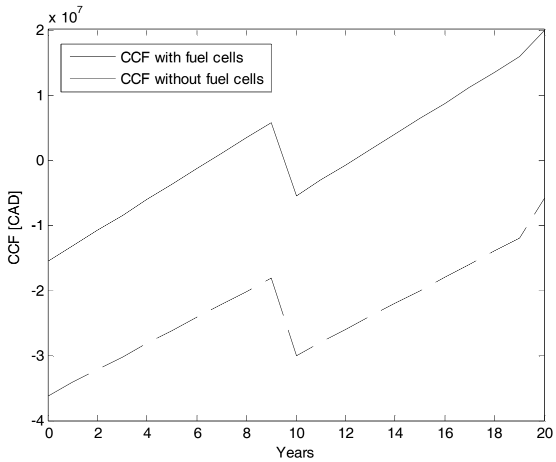


Fig. 3: Cumulative cash flow (CCF) with and without fuel cells.

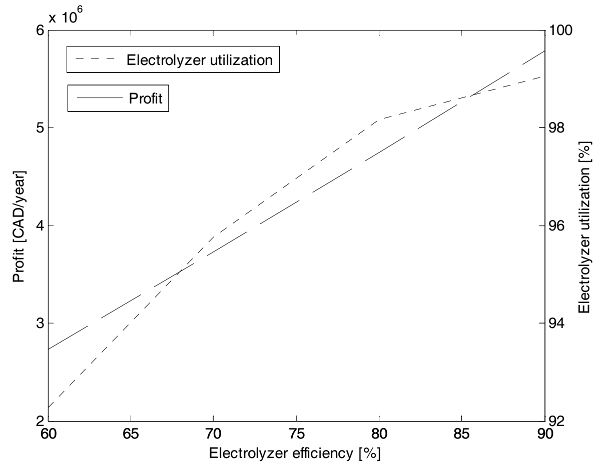


Fig. 4: Profit and electrolyzer utilization with respect to electrolyzer efficiency.

zero for $c_{p,i}^{M}$ values greater than 78.3 CAD/MWh. If a higher efficiency of 27 kg/MWh (90%) is considered, the electrolyzer would be dispatched at prices below 117.45 CAD/MWh. Similarly, the fuel cell would be utilized when the price of electricity exceeds 217.5 CAD/MWh, for a hydrogen selling price of 4.35 CAD/kg and an efficiency of 50 kg/MWh (60%), or when the price exceeds 289.99 CAD/MWh, if the efficiency is 66.66 kg/MWh (45%). Since the price of electricity rarely reaches these levels, the fuel cell utilization would be very low, as shown in Tables V and VI ( $P_{w,p,i}^{STGDISCH}$ , $\hat{P}_{i}^{STGDISCH}$ ). Notice that an increase in the hydrogen selling prices decreases the utilization and profitability of electricity generating stationary fuel cells, whereas an increase of efficiency of the fuel cells increases them.

### *B. Base Case Scenario*

The base case scenario (BCS) is based on the system data mentioned in the previous section. This is the most probable scenario in practice, and is further divided into four sub-scenarios based on price forecasts, with and without error, for the system with and without stationary fuel cells. The investment evaluation results obtained excluding fuel cells

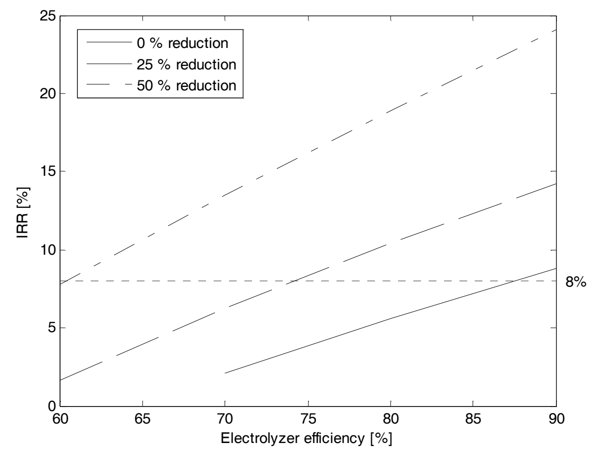


Fig. 5: IRR with fuel cells for various electrolyzer efficiencies and equipment price reductions.

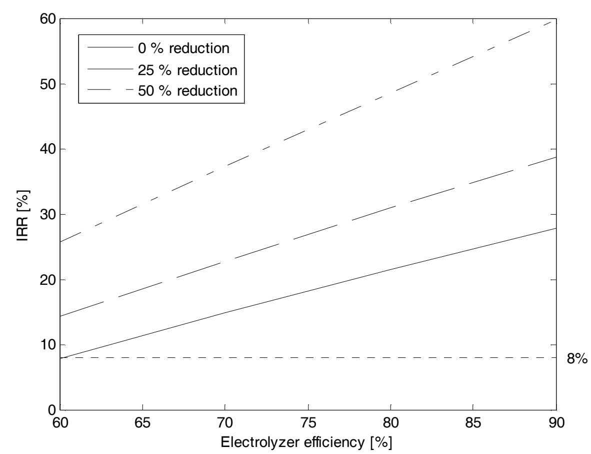


Fig. 6: IRR without fuel cells for various electrolyzer efficiencies and equipment price reductions.

(NFC) and including them (FC), with (FE) and without (NFE) forecast errors are presented in Table VII. The governmental support is already considered in the investment costs, so that the initial investment costs stated in this table are 75% of the actual initial investment costs. Neither forced outages of electrolyzers nor the scheduled outages for maintenance were considered. Observe that the hydrogen subsystem with stationary fuel cells is not profitable, due to the high costs and low utilization of those fuel cells; this is reflected in negative values for NPV and IRR.

The electrolyzer utilization is considerably higher, at about 93%. The forecasting error is shown to have only limited impact on profitability of the system with fuel cells, and no impact on the system without fuel cells; this is due to efficiency of fuel cell power modules and the relatively high hydrogen selling prices compared to electricity prices. Thus, the hydrogen is produced and sold when prices of electricity fall below the aforementioned 78.3 CAD/MWh, almost regardless of the results of the pre-dispatch phase. Notice that by omitting the under-utilized stationary fuel cells, the projects IRR is 9.6%, making it profitable enough

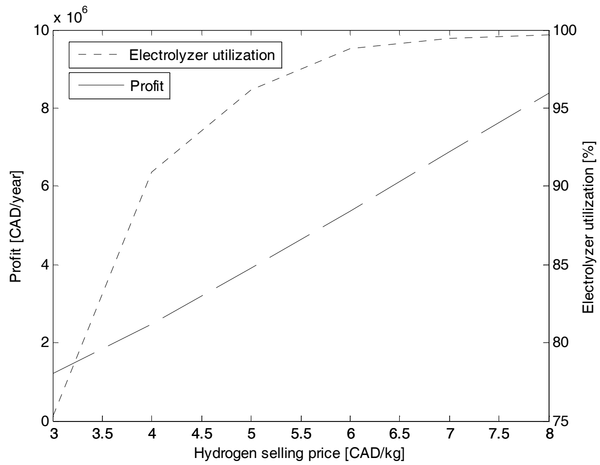


Fig. 7: Profit and electrolyzer utilization with respect to hydrogen selling prices.

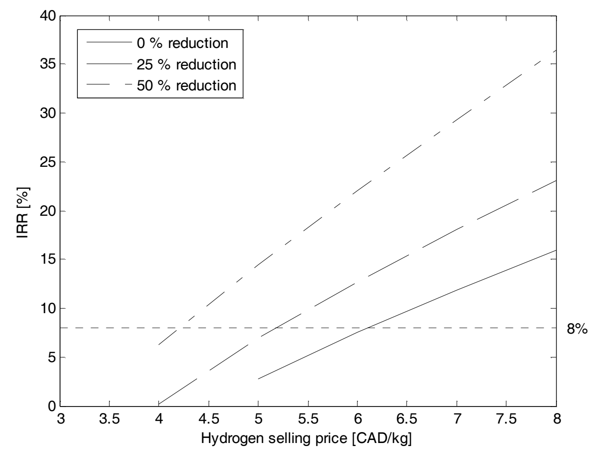


Fig. 8: IRR with fuel cells with respect to on hydrogen selling prices.

to invest on it. Figure 3 shows the cumulative net cash flows (CCF) with and without fuel cells including price forecast errors. The cash flows are nominal values, i.e. no discounting to present value is considered. The scenarios without price forecast errors result in similar cash flows. It is evident from the figure, that the hydrogen subsystem with stationary fuel cells never becomes profitable, since the cumulative cash flow never exceeds the zero margin. The scenario without stationary fuel cells, on the other hand, is shown to be profitable. Observe the considerable change on cash flows in year ten; this is due to replacement of electrolyzers at full costs in that year. In the last year of the project, the effect of salvage values is clearly visible. It should be highlighted that because the system is mainly utilized for hydrogen production instead of electricity storage, due to low fuel cell utilization, the price and wind forecasts do not have any significant impact on the system profitability. For different hydrogen and electricity prices and efficiencies, these forecasts may have a more significant effect on the system economics.

*C. Sensitivity Analysis*

The sensitivity analysis is based on the BCS, and concentrates on studying the following main issues:

1. Effect of efficiency of electrolyzers and fuel cell power modules.
2. Effect of hydrogen selling price.

Impacts of equipment prices, price forecasting errors and exclusion of fuel cells are also considered in all these studies. Sensitivities with respect to other parameters, such as the hydrogen subsystem dimensions, were not studied due to the fact that, from the results presented in the previous two sections, one can conclude that their effects would not be significant on the system under study.

*1) Fuel cell and Electrolyzer Efficiencies*

In this section, the efficiencies of fuel cells and electrolyzers were assumed to vary from 45% to 60% for the fuel cell power modules, and 60% to 90% for the electrolyzer subsystem. The results obtained indicate that the utilization of stationery fuel cell power modules is near zero for all studied efficiencies; this is due to the fact that electricity prices should exceed 217.5-289.99 CAD/MWh, depending on the efficiency of the fuel cells, for the fuel cells to be utilized, which rarely happens in the current market, as previously discussed. Based on this, the profit, electrolyzer utilization and internal rates of return depend solely on electrolyzer efficiency. In Fig. 4, the profit and electrolyzer utilization are shown with respect to the electrolyzer efficiencies. The results show almost linear dependency of profit and electrolyzer utilization with respect to efficiencies. The price and wind forecast errors do not have any considerable impact on the profitability and utilization of stationary fuel cells and electrolyzers, as well as on internal rates of returns, similar to what is reported in the previous section.

The IRR of the project with respect to electrolyzer efficiencies are depicted in Fig. 5. Different equipment price reductions are considered here, considering also a governmental initial investment support of 25%. Observe that equipment prices strongly impact the profitability of the hydrogen subsystem; the higher the reduction, the higher the profitability of the hydrogen subsystem. If one assumes an IRR of 8% to be the marginal value for the investment to be profitable, then 50% price drops with efficiencies of above 60%, or 25% price drops with efficiencies above 75%, are sufficient for the subsystem to be attractive to potential investors.

A similar study without stationary fuel cells is depicted in Fig. 6. This figure shows higher economical benefits if fuel cells are omitted, as expected.

*2) Hydrogen Selling Price*

The second part of the sensitivity analysis was devoted to hydrogen selling prices, assuming a range of 3 CAD/kg to 8 CAD/kg. Again, a very limited impact of price and wind forecast errors on profitability of the system was observed. The effect on profit and utilization of electrolyzer versus hydrogen selling price is illustrated in Fig. 7.

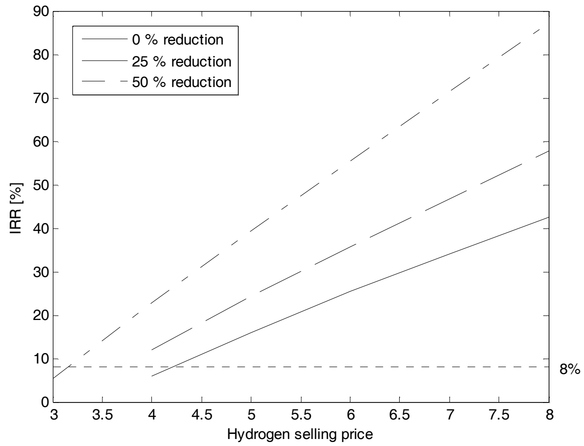

Fig. 9: IRR without fuel cells with respect to hydrogen selling prices.

Observe that utilization is close to 100% for prices above 6 CAD/kg. The profit is almost linearly dependent on hydrogen prices, with an approximate slope of 1'420,000 CAD per each CAD/kg hydrogen selling price increase. The impact of the hydrogen selling prices on the profitability of the subsystem with respect to equipment price costs is depicted in Fig. 8. These results show that the IRR of the hydrogen subsystem increases as hydrogen prices increase. The complete subsystem becomes economically viable at hydrogen prices above 6 CAD/kg in the base case scenario; at lower equipment prices the system becomes profitable at lower hydrogen prices. The economic viability of hydrogen subsystem without stationary fuel cells is presented in Fig. 9.

### D. *Transmission Congestion Scenario*

In addition to the base case scenario with sensitivity analyses, a scenario considering limited transmission line capacities is considered here, addressing possible delays in the planned transmission expansion in the Bruce area [30]. Therefore, the possibility that the energy produced by Bruce Power and wind generators is not going to be entirely transferable to end-users is investigated.

The line capacity is assumed to remain unchanged with regards to the base-case scenario. The refurbished Bruce power plant is foreseen to increase its capacity by 1500 MW, resulting in a total capacity of 6320 MW. Any other potential generation developments in the area are not considered. With same capacity factor used in the base case scenario, this capacity expansion would result in 5207 MW of constant electricity production by the NPP.

With the addition of 9 MW of Huron Wind's wind power, the installed capacity of the hydrogen subsystem to supply for the potential lack of transmission capacity is assumed to be 216 MW. The suitable hydrogen subsystem for storing this amount of excess electricity is presumed to consist of 750 electrolyzers with total hydrogen production capacity of 4045.43 kg/h. The compressor, storage tank and fuel cell arrays are assumed to be comprised of 939, 2355 and 914 units, respectively.

The results for the congestion scenario studies are shown in Table VIII. They show higher profitability of the hydrogen subsystem compared to other scenarios, due to the use of energy for hydrogen production, which would otherwise be limited by transmission line congestion. This further constraints the use of stationery fuel cells, resulting in no utilization of these devices, since their electricity production cannot be transmitted. However, the overall profitability of the Nuclear-Wind-Hydrogen system is higher than in the previous case, where there was no transmission limitation.

## VI. Conclusions

The feasibility of a wind-farm and nuclear power plant in the context of a Hydrogen Economy has been studied in this article. A novel methodology has been developed taking into account all important factors in the economic evaluation of projects for investment purposes. The proposed methodology was used to study the feasibility of a realistic wind-nuclear-hydrogen system located in Ontario, Canada. The results show that for the given realistic assumptions, hydrogen is not a viable option for electricity storage at this time for the current electricity market and pricing. It is also shown, that price and wind forecasting errors do not play a major role in the feasibility studies presented.

The hydrogen subsystem for producing hydrogen is shown to be profitable, if a hydrogen demand (e.g. for transportation applications) is considered; in that case, one can conclude from these studies, that it might be viable to produce hydrogen from electricity and invest in hydrogen production equipment in an existing mixed wind-nuclear energy hub. The profitability of such system is increased when limited transmission capacities prevent the selling of all the electricity produced to the electricity market, since in this case, the electricity is converted to hydrogen and sold to the hydrogen market. Thus, the hydrogen production option, in this context, may also be an alternative for grid expansion, especially in locations where such expansion is not an option due to environmental, local or other reasons.

In future research, there is a need to focus on the application of the proposed models and analysis methodology to other possible system configurations and issues. For instance, the selling of byproducts such as oxygen from the electrolyzer and heat from the fuel cells may add economic value to the hydrogen subsystem.

## VII. References


[1] A. I. Miller, R. B. Duffy, "Integrating large-scale co-generation of hydrogen and electricity from wind and nuclear sources (NUWIND ©)", IEEE EIC Climate Change Technology, pp. 1-9, May 2006.

[2] National Research Council and National Academy of Engineering, "The Hydrogen Economy: Opportunities, Costs, Barriers and R&D needs", The national Academies press, Washington, 2004.

[3] R. R. Sadhankar, J. Li, H. Li, D. K. Ryland, S. Suppiah, "Future Hydrogen Production Using Nuclear Reactors", IEEE EIC Climate Change Technology, pp. 1-9, 2006.

[4] B.D. Shakyaa, Lu Aye, P. Musgrave, "Technical feasibility and financial analysis of hybrid wind–photovoltaic system with hydrogen storage for Cooma", International Journal of Hydrogen Energy, Vol. 30, pp. 9-20, 2005.
[5] D.B. Nelson, M.H. Nehrir, C. Wang, "Unit Sizing of Stand-Alone Hybrid Wind/PV/Fuel Cell Power Generation Systems", IEEE PES General meeting, Vol. 3, pp. 2116-2122, June 2005.
[6] M. Korpas, A. T. Holen, "Operation Planning of Hydrogen Storage Connected to Wind Power Operating in a Power Market", IEEE Transactions on Energy Conversion, Vol. 21, No. 3, 2006
[7] A. Miller, R. Duffey, "Sustainable and economic hydrogen cogeneration from nuclear energy in competitive power markets", Energy, Vol. 30, pp. 2690-2702, 2005.
[8] J. Matevosyan, L. Soder, "Minimization of Imbalance Cost Trading Wind Power on the Short-Term Power Market", IEEE Trans. On Power Syst., Vol. 21, No. 3, August, 2006.
[9] J. Gonzales, R. Moraga, L. Matres, A. Mateos, "Stochastic joint optimization of wind generation and pumped-storage units in an electricity market".
[10] International Energy Agency, "Guidelines for the economic analysis of renewable energy technology applications", Paris, 1991.
[11] D. Allen, "Economic evaluation of projects", Institution of chemical engineers, Third edition, 1991.
[12] Renewable Energy Development in Ontario (REDO), "General information for potential developers", 2005.
[13] Michael Fowler, "Renewable Energy Generation Facility Design Report", University of Waterloo, 2006.
[14] H. Zareipour, "Price Forecasting and Optimal Operation of Wholesale Customers in a Competitive Electricity Market", PhD thesis, 2006.
[15] Independent Electricity System Operator, "Market Manual 9: Day-Ahead Commitment Process Operations and Settlement", Issue 4.0, March 2007.
[16] Independent Market Operator (now IESO), "Market Manual 4: Market Operations Part 4.0: Market Operations Overview", Issue 9.0, June 2004.
[17] Huronwind, "Facts and figures", 2003. [Online]. Available: http://www.huronwind.com/huronwind/hw_pdfs/34.pdf.
[18] Bruce Power, "2004 year review", 2004. [Online]. Available: http://www.brucepower.com/uc/GetDocument.aspx?docid=952.
[19] Hydrogenics Corporation, "Hystat-A Hydrogen plants brochure". [Online]. Available: http://hydrogenics.com/onsite/pdf/Hydrogen_Plants_web.pdf
[20] J. X. Weinert, T. E. Lipman, "An Assessment of the Near-Term Costs of Hydrogen Refueling Stations and Station Components", Institute of transportation studies, University of California, Davis, 2006.
[21] Presure product industries, "Fuel cell station compressor -brochure". [Online]. Available: http://www.pressureproductsindustries.com/pdfs/PPI_HP340_fuelcell.pdf
[22] Hydrogenics Corporation, "HyPM 500 series power module fuel cell brochure".
[23] F. Doty, "A Realistic Look at Hydrogen Price Projections", Doty Scientific, Inc. Columbia, 2004. [Online]. Available: http://www.dotynmr.com/PDF/Doty_H2Price.pdf
[24] International Energy Agency, "World energy outlook 2006", 2006.
[25] W. A. Amos, "Costs of storing and transporting Hydrogen", NREL, November 1998.
[26] IESO, "Hourly Ontario Energy Price (HOEP)", [Online]. Available: http://www.ieso.ca/imoweb/marketdata/marketData.asp
[27] R. Fourer, D. M. Gay, B. W. Kernighan, "AMPL: A Modeling Language for Mathematical Programming", Duxbury Press, 2 edition, November, 2002.
[28] ILOG, "ILOG AMPL CPLEX System Version 10.0 User's Guide", January, 2006.
[29] MATLAB, "Matlab Online Manuals". [Online]. Available: http://www-ccs.ucsd.edu/matlab/fulldocset.html
[30] Ontario Clean Air Alliance, "A new Bruce transmission line: Does it make sense for Ontario?", Air Quality Issues Fact Seet #23, 2007. [Online]. Available: http://www.cleanairalliance.org/resource/fs23.pdf

## VIII. BIOGRAPHIES

**Gregor Taljan** (SM'06) received his Electrical engineer diploma from the University of Ljubljana, Slovenia in 2005. He is a PhD student at the Faculty of Electrical Engineering, University of Ljubljana, working as young researcher in the Laboratory for Power Systems and High Voltage. He is currently a visiting scholar at the University of Waterloo, Canada. His research interests are in power system operation and economics and reliability evaluation of power systems.

**Michael Fowler** received his B.Eng. in Fuels and Materials Engineering from Royal Military College of Canada (RMC) in 1986, MASc in Engineering Chemistry from Queen's University in 1988. Following a career as Military Engineer in the Canadian Forces and working as an Environmental Management Consultant he completed a PhD at RMC in 2003. Dr. Michael Fowler is currently an Assistant Professor in the Department of Chemical Engineering at the University of Waterloo with a research interests in fuel cell system design and reliability, fuel cell materials durability and green power systems.

**Claudio Cañizares** (S'86, M'91, SM'00, F'07) received the Electrical Engineer degree from Escuela Politecnica Nacional (EPN), Quito-Ecuador, in 1984 where he held different teaching and administrative positions from 1983 to 1993. His MSc (1988) and PhD (1991) degrees in Electrical Engineering are from University of Wisconsin-Madison. He has been with the E&CE Department, University of Waterloo since 1993, where he has held various academic and administrative positions and is currently a full Professor. His research activities concentrate in the study of stability, modeling, simulation, control and computational issues in power systems within the context of competitive electricity markets. Dr. Cañizares has been the recipient of various IEEE-PES Working Group awards, and currently holds and has held several leadership appointments in IEEE-PES technical committees and subcommittees, as well as working groups and task forces.

**Gregor Verbic** (S'98, M'03) received in December 1995 the Electrical Engineer diploma from the University of Ljubljana, Slovenia. He joined Korona Power Engineering in 1995 where he worked for three years. His MS (2000) and PhD (2003) degrees in Electrical Engineering are from the University of Ljubljana. Dr. Verbic is now an Assistant Professor at the University of Ljubljana, Faculty of Electrical Engineering. In 2005, he was a NATO-NSERC Postdoctoral Fellow at the University of Waterloo, ON, Canada. His research activities are power-system operation, dynamics and control.