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ECONOMIC AND ENVIRONMENTAL FEASIBILITY STUDY OF HYDROGEN-NATURAL GAS CO-STRORAGE

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***Abstract*— Underground storage of hydrogen with natural gas (UHNG) is a novel compound technology which has been proposed to provide utility-scale energy storage capacity. This technology revolves around the use of electrolyzers to convert electrical energy to chemical energy in the form of hydrogen, then, hydrogen is injected underground, along with natural gas, into existing natural gas storage facilities. Finally, depending on the particular application, the energy stored as hydrogen can be recovered in different forms: as hydrogen for industrial and transportation applications, as electricity to serve power demand, or as hydrogen-enriched natural gas to serve gas demand. It is found that, if operated as the decision points have specified, at the end of three years, the concentration of hydrogen in the reservoir is expected to increase to 2%. Also, it is found that it is not profitable to sell the hydrogen-enriched natural gas at the same price as regular natural gas.**

Index terms— **Hydrogen; Natural gas; Underground storage; Process simulation; Emissions**

I. INTRODUCTION

In the context of electric power supply chains, this paper addresses the surfacing issues related to surplus base load generation and the deployment-related intermittent nature of renewable energy generators. In solution to the problems at hand, utility-scale energy storages are able to act as energy buffers to both generation and demand management dispatches.

Utility-scale energy storages offer a wide-range of applications which require associative technologies related to criteria of energy storage capacity, and rated input and output; each technology is unique in its conversion method of electrical energy to storable energy units. Such technologies include, batteries, compressed air energy storage (CAES), and pumped hydro energy storage [1-6].

A noteworthy and new technology is the underground storage of hydrogen mixed with natural gas (UHNG). UHNG uses electrolysis to store energy by converting electrical energy to hydrogen, which is then introduced to natural gas so that the mixture can be stored. UHNG is attributed with features unique to all other technologies: UNGH is constructed of technically superior and modern components; UNGH is a more physically complex system owing to the fact that its performance is contingent on its constituent technologies; UNHG is afforded several energy recovery pathways, unlike other technologies.
Thus, UHNG is a potentially innovative technology, which has yet to prove itself; its use of multiple energy vectors deviates from conventional forms of energy storage, and its overall performance is contingent upon the exact configuration of its constituents.

- RESEARCH OBJECTIVE AND APPROACH

The objectives of this paper is to achieve a better understanding of the technology of underground storage of hydrogen with natural gas, by investigating its dynamic behavior, financial and environmental performance. The goal is to simulate conditions which are likely to be in place a short time after the implementation of the underground storage of hydrogen: hydrogen is produced and injected into the natural gas storage system in relative small proportions (Fig. 1).

Model Overview

In order to study the dynamic behavior of UHNG, a mathematical model is built using a MatLAB-Simulink graphical modeling environment. Once the dynamic physical behavior of an energy hub employing UHNG is determined for the case study, the corresponding financial and environmental performance of the system can be determined.
The main technological components, as shown in Fig. 1, are the electrolyzer and storage reservoir. The dynamic behavior of each block is dependent on fixed technological constraints, but also on conditions and process variables which can be manipulated to optimize the process. Rated capacity of reservoir is assumed to be 6.1-7.6 MMSCF, while that of electrolyzer is 8.7 MW.
The decision point D_2 indicated in Fig. 1 determines whether the electrolyzer is operated to produce electricity, depending on the hourly price of grid power. The threshold

value used in determination is the 24 hours moving average of the Hourly Ontario Energy Price (HOEP) from the IESO [7]. It is estimated that, whenever the HOEP is lower than its daily moving average, the demand for electricity is lower than average, thus it is preferable to use grid power to supply electrolytic hydrogen production, when surplus base load generation is more plentiful. Vice versa, when HOEP is higher than its daily moving average, the electrolyzers are in stand-by as not to increase electricity demand during those hours. This practice ensures that the electrolyzer is operated daily during the off-peak hours.

In addition, the decision D3 determines whether the hydrogen produced by the electrolyzer is sent to storage. As input, it requires the knowledge of the reservoir injectability/deliverability and the flow rate of hydrogen produced. Hydrogen is sent for storage if it has been produced and if the reservoir could accept injected gas. In the case that the hydrogen produced exceeds the injectability of the reservoir, or in the case that the reservoir is producing gas from storage, the portion of hydrogen that cannot be injected is assumed to be absorbed by local hydrogen demand, immediately. This assumption can be verified by examining the amount of hydrogen thus consumed from simulation results.

Furthermore, the penultimate decision point, D4, determines how much natural gas is blended with the hydrogen that is to be injected. In this scenario, the amount of natural gas alongside hydrogen is calculated based on the injectability of the reservoir. It is set up so that the combined mixture fulfills the injectability limit exactly, so that the maximum amount of gas is injected into the reservoir during its operations.

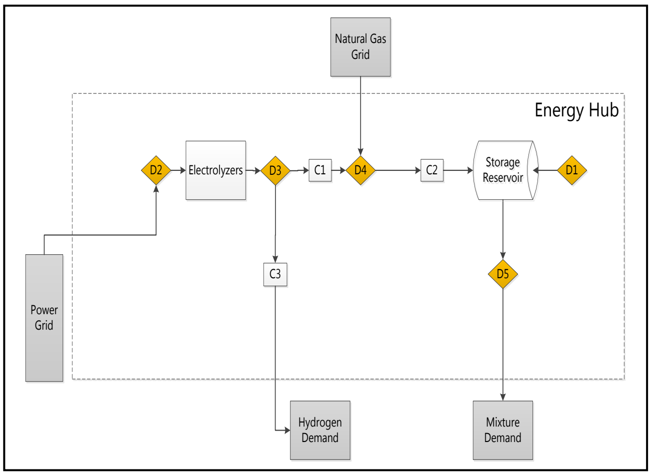


Fig. 1. Model scope for hydrogen injection

- Results and Discussion

As mentioned before, the operations of the energy hub are identical to those in the case when there is no electrolyzer in the model, with the exception that hydrogen is being injected into the reservoir during periods of low electricity prices. The dispatch of injectability/deliverability to the reservoir is drawn in Fig. 2.

The actual hourly flow rates into and out of the reservoir are the same as the deliverability/injectability values set by the reservoir model, as specified at decision points D4 and D5 as shown in Fig. 3. The actual hourly flow rates into and out of the reservoir are the same as the deliverability/injectability values set by the reservoir model, as specified at decision points D4 and D5 as illustrated in Fig. 4.

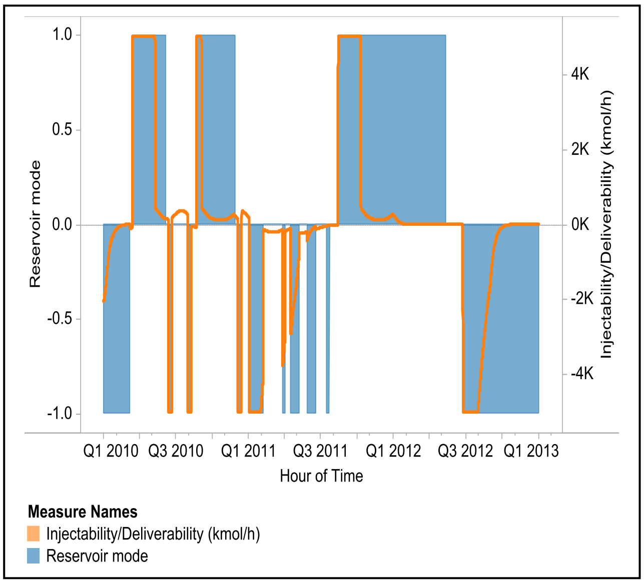


Fig. 2. Dispatch to reservoir with the hydrogen injection consideration

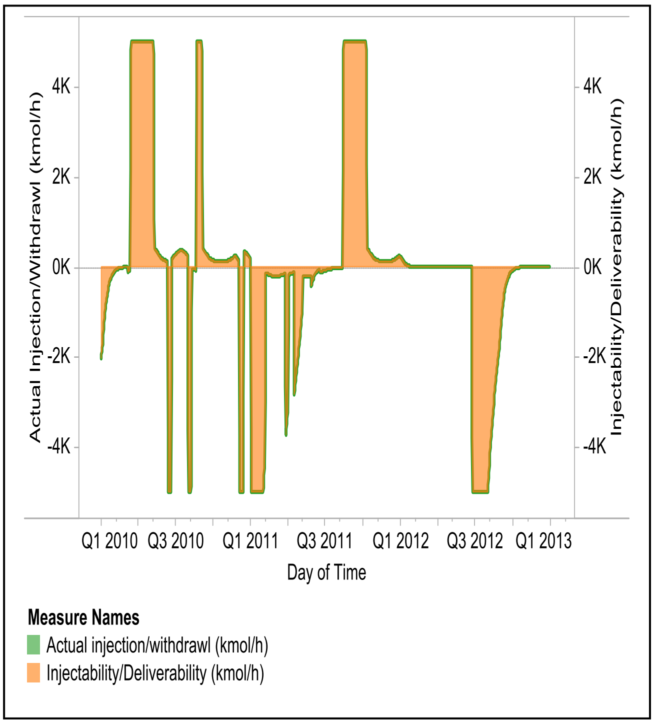
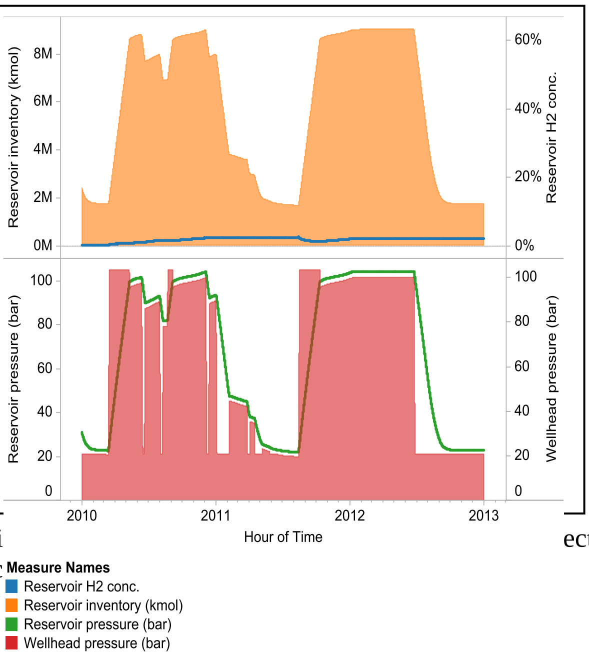


Fig.3. Injectability/deliverability and actual reservoir flow rates

The concentration of hydrogen of the stored gas is now non-zero: the three year average of the reservoir hydrogen concentration is about 2%. The injected hydrogen is produced using power grid, when market price of electricity is relatively low. The electrolyzer used for the production of hydrogen shows an average utilization factor of 50% as shown in Fig. 5. Over the three years, only 36.5% of the hydrogen produced is stored, the rest needs to be absorbed by client demand at the time of production (Fig. 6).



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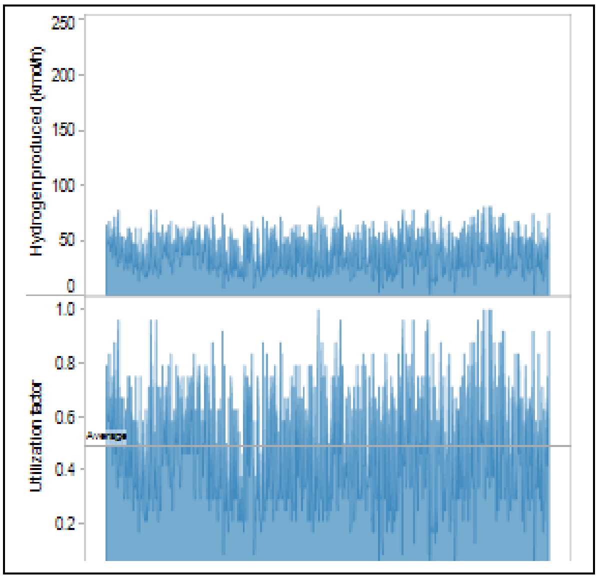

Fig.5. Electrolyzer utilization for the hydrogen injection scenario

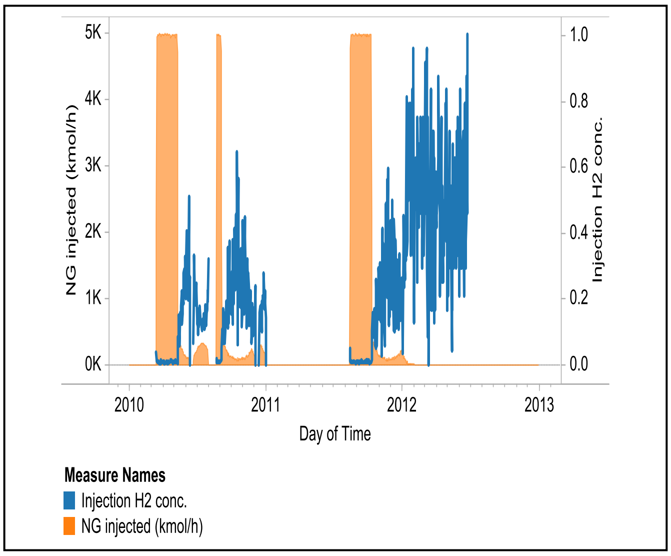

Fig.6. Flow rates of injected streams for the hydrogen injection scenario

The net annual cash flow for the simulation and the net greenhouse gas emission reduction are presented in Table 1.

TABLE 1. Net annual cash flow

Annual Cash Flow	**Average ($)**
1. Capital costs	2,979,026
2. OM costs	235,891
3. Cost of sales	20,359,813
4. Sales	19,411,763
5. Annual net	**4,162,967**
Netgreenhouse gas emission reduction (kg CO2/year)	3.41E+06

II. Conclusions

This paper involves the injection of hydrogen into the reservoir along with natural gas. The only pathway for energy recovery is the distribution and used of hydrogen-enriched natural gas by off-site users. This method can also be known as the Power to Gas pathway. It is found that, if operated as the decision points have specified, at the end of three years, the concentration of hydrogen in the reservoir is expected to increase to 2%. Also, it is found that it is not profitable to sell the hydrogen-enriched natural gas at the same price as regular natural gas; in order to break even with the additional costs required by the electrolyzer, a 16% premium is needed for the mixture.

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