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Compressed air energy storage with waste heat export: An Alberta case study

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ABSTRACT

Interest in compressed air energy storage (CAES) technology has been renewed driven by the need to manage variability form rapidly growing wind and solar capacity. Distributed CAES (D-CAES) design aims to improve the efficiency of conventional CAES through locating the compressor near concentrated heating loads so capturing additional revenue through sales of compression waste heat. A pipeline transports compressed air to the storage facility and expander, co-located at some distance from the compressor. The economics of CAES are strongly dependant on electricity and gas markets in which they are embedded. As a case study, we evaluated the economics of two hypothetical merchant CAES and D-CAES facilities performing energy arbitrage in Alberta, Canada using market data from 2002 to 2011. The annual profit of the D-CAES plant was \$1.3 million more on average at a distance of 50 km between the heat load and air storage sites. Superior economic and environmental performance of D-CAES led to a negative abatement cost of −\$40/tCO_2e. We performed a suite of sensitivity analyses to evaluate the impact of size of heat load, size of air storage, ratio of expander to compressor size, and length of pipeline on the economic feasibility of D-CAES.

1. Introduction

Electric system operators dispatch the generation fleet in response to fluctuations in the load and to ensure grid reliability. Baseload power plants are characterized with low marginal costs, low ramp rates and high start up costs. Such inherent properties can lead to their part-load and less efficient operation and also depressed electricity prices during periods of low demand. On the other hand, peaking plants have low start up costs, fast dispatch, and high fuel costs. The variations in load and technical characteristics of the generation fleet cause fluctuations in electricity prices as well as inefficient and more polluting operation of the electricity sector. Penetration of intermittent renewable energies into the electric grid could worsen the volatility of prices. Low marginal cost of wind and solar-based electricity would depress price of off-peak electricity [1]. At the same time, forecast errors, uncertainty, and rapid changes in the output of these plants could increase the price of peak electricity [2,3].

Price volatility of electricity is a business opportunity for energy arbitrage by energy storage plants. In addition to direct financial gains for the plant itself, an energy storage unit may benefit the electric system (positive externalities) in numerous ways such as increasing the capacity factor of baseload plants and intermittent renewables [4–6] and reducing grid congestion [7,8]. Pumped hydro storage (PHS) and compressed air energy storage (CAES) are the two primary technologies for bulk storage of electric energy (hundreds of MW-hours) [9]. Development of PHS is constrained by factors such as the need for sufficient elevation difference between the two reservoirs, large footprint, relatively high capital costs, and environmental licensing [5,10].

CAES facilities buy electricity when prices are (relatively) low to run large compressors and store electricity in the form of compressed air which later is combusted to power modified gas turbines (air expanders) when prices are high. CAES plants can store air in both underground (e.g. salt caverns) and aboveground reservoirs (pressure vessels) and thus have more siting flexibility [5]. Furthermore, they have shorter construction time (around three years) and are less capital intensive compared to PHS projects [11]. There are currently two operating utility-scale CAES plants in the world. The first one is in Huntorf, Germany with an output of 290 MW over four hours, while the second plant is in McIntosh, Alabama and can generate 110 MW of electricity for 26 hours [5].

Efficiency and economics of CAES have been improved since the commission of the Huntorf plant in 1978. Recuperating heat from exhaust of the air expander in order to preheat air prior to entering the combustor reduced fuel requirements of the McIntosh plant by 25% [7]. Among various CAES designs, Adiabatic and Distributed

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Nomenclature

CapEx	specific capital cost ($/MW)
CCR	capital charge rate (%)
D	diameter of pipeline (mm)
El	electric energy (MWh)
ER	energy ratio (non-dimensional)
f	friction factor of pipeline (non-dimensional)
FOM	fixed operating and maintenance cost ($/kW/year)
Heat	heating energy (MWh)
HR	heat rate (GJ/MWh)
L	length of pipeline (km)
P	pressure (kPa)
Q	flow rate (m^3/day)
T	temperature (K)
VOM	variable operating and maintenance cost ($/MWh)
Z	compressibility factor (non-dimensional)
Greek	
η	efficiency (%)

Subscripts and superscripts

CAES	compressed air energy storage
Comp	compressor
Day	number of days in planning horizon
D-CAES	distributed compressed air energy storage
Down	downstream of pipeline
Exp	expander
Exp-Comp	portion of expander output used by compressor
h	hour
HOB	heat-only-boiler of district heating system
HRU	heat recovery unit
NG	natural gas
Pipe	air pipeline
Pur	electricity purchased from the market
Resv	depleted natural gas reservoir
Sold	electricity sold to the grid
Up	upstream of pipeline

CAES are of special interest. They both aim to address efficiency losses associated with waste heat of the compressor. In adiabatic CAES, air is adiabatically compressed to high pressures and temperatures and its heat is recovered prior to storage. The compression heat is stored in a thermal energy storage facility to reheat compressed air during the discharge phase. Utilization of compression heat can negate and even eliminate the need for combustion of fuel and consequently increase the efficiency of the plant [7]. However, this design is still in the research and development phase as its technical and economic feasibility is challenged by the need for high pressure and high temperature compressors and thermal energy storage facilities as well as high pressure expanders [12,13].

Distributed compressed air energy storage (D-CAES) aims to enhance efficiency and economics of CAES by utilizing the compression heat for space and water heating applications. The D-CAES concept was first proposed by the authors in an another paper [14] and a patent [15]. Energy used for municipal heating applications could be of low exergy content (low temperature) in contrast to the heating energy required for Adiabatic CAES which imposes technical difficulties to and cost burdens for this technology. The compressor of D-CAES is located near high heat load centers, such as downtown core. This configuration is in contrast to the conventional CAES in which the compressor is co-located with the expander and air storage. Compression heat would be recovered through a heat recovery unit (HRU) and sold to meet space and water heating loads with the aim of a district heating network. The downside of D-CAES is the need for a pipeline to transport compressed air from the compression facility (co-located with heat load) to the storage site located at favourable geological formations. Therefore, the capital cost of D-CAES is higher compared to conventional CAES despite its lower operational cost because of the revenue stream associated with waste heat recovery. Obviously, a D-CAES can be only economically feasible where the air storage site is in the vicinity of the heat load, otherwise the cost of pipeline would outweigh revenues from heat recovery. In some markets, the carbon emission reductions that occur when waste heat displaces gas may have a separate economic value such as a carbon credit, reduction in tax, or other instruments.

Our previous paper [14] evaluated the competitiveness of D-CAES with conventional CAES, simple cycle, and combined cycle gas turbines at a system level (i.e. minimizing the entire cost of electricity generation or maximizing the net social welfare) in a carbon-constrained world. Here we extend our earlier work to examine the performance of D-CAES under real-world market conditions. This paper compares the economics of CAES and D-CAES in a deregulated electricity market based on historical data. Both facilities are dispatched as stand-alone merchant plants performing energy arbitrage to maximize their own profitability. They are equipped with a 131 MW expander, a 105 MW compressor and a depleted gas reservoir with 1572 MWh of generation capacity in the base case scenario. The air storage site is located 50 km away from a concentrated heat load (five times larger than the University of Calgary, Canada). Price of natural gas, as a primary fuel for municipal heating would directly impact revenues associated with waste heat recovery. On the other hand, it can affect the price of electricity and thus the revenues of energy arbitrage. The main contribution of this paper is evaluating the effect of market conditions (gas and electricity prices) and design parameters (e.g. length of pipeline) on the economic competitiveness of D-CAES with conventional CAES system in energy arbitrage applications.

One should note the underlying assumption in this paper is that both facilities are price–takers. This implies the storage plants are not sufficiently large so that their operation could affect the dynamics of the market and change the price of electricity or gas. If the size of the compressor becomes comparable to the system load, then the price of off-peak electricity would likely rise (due to higher demand). This would be beneficial to the suppliers (higher sales and less cycling) while unfavourable to the consumers (including the storage plant itself due to higher prices). On the other hand, the ability of a large expander to deliver significant volumes would depress the price of peak electricity. This situation would indeed benefit the consumers (lower charges) and the grid (less need to dispatch less efficient peaking plants). However, this would hurt the profitability of the peaking plants, including the storage facility itself. Studying such possible effects are not in the scope of this paper. On the grounds that the size of the modeled compressor and expander are approximately 1% of the minimum annual load and the total installed generation capacity respectively, the authors have assumed that operation of the studied storage plants would not impact the dynamics of the market.

2. Methodology

This paper investigates potential financial gains associated with heat recovery for space and water heating applications from the