Can CCS become a battery?

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ABSTRACT

Approaches to energy storage beyond electrochemical systems include pumped hydropower, flywheels, and compressed air energy storage (CAES); and technically, could also include the use of compressed carbon dioxide for providing both work and cooling services in industrial settings. This paper shows how one operational mode of compressed carbon dioxide energy storage (CDES) could enhance plant output by 10% and lead to a non-trivial increase in financial performance for a power generator. The successful CDES system could be more effective at increasing plant valuation than a plant expansion of equivalent capacity. The aim of this study is to characterize one version of the CDES concept, and to highlight innovation and analysis needs that could lead to economically feasible demonstrations.

Keywords: ccs, co2, utilization, storage, cooling

1 INTRODUCTION

It is challenging to construct a business case for Carbon Capture and Storage (CCS) without a supportive revenue model or adequate policy. Most CCS projects that attained financing at least in Y2015 relied on carbon dioxide (CO_2) utilization revenues through Enhanced Oil Recovery (EOR) markets; but EOR is deemed insufficient for growing CCS projects numerically and geographically [1]. Additional approaches are needed for delivering useful CO_2-based products or services to customers.

Among a plurality of promising CO_2 utilization pathways in commercial use or under development, energy storage is beginning to receive attention as one approach for utilizing CO_2 and thus for supporting a CCS business case. In many cases, CO_2 utilization for value-added services or products can be viewed as energy storage; e.g., consider CO_2-based refrigeration and CO_2-derived fuels. The primary focus of this study is the storage and utilization of mechanical energy by means of compressing and decompressing CO_2. Compressed CO_2 can be used as an energy storage system and one version of this approach has been conceptualized as "Earth Battery", which is a multi-fluid approach having integration with geothermal resources [2]. Unlike CAES, the highly exothermic gas compression step does not dissipate energy to the surroundings or need thermal storage solutions – the heat generated during CO_2 compression can be recovered by heat integration within a CCS plant.

To simplify the present study, consider that CO_2 is captured and transported by pipeline to a power plant seeking to implement CDES service. Figure 1 illustrates different types of configurations that may be considered. The CDES system refers to configurations IIA, IIB, IIC and derivatives. Configuration I and III, respectively, are the original plant and a conventionally-expanded original plant.

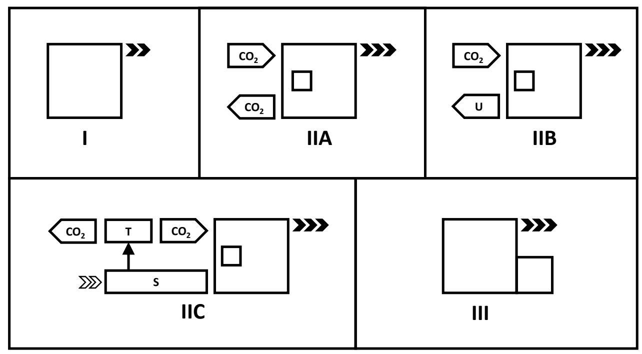

Figure 1: Representations of power plant configurations; [I] original plant, [IIA-C] modified plant using CDES service augmentation, [III] original plant with expansion. Full and hollow arrow tips represent electricity transmitted to and from the grid; U=utilzation; S=storage; T=transport.

In configurations of Type II, the CO_2 may be processed in at least two modes based on how the process begins: (1) isoenthalpic expansion followed by cooling service, and (2) isobaric heating followed by isoentropic expansion for power service. An example of the former mode is described in Figure 2 and is well suited for cooling service as it resembles, in part, the first half of commercial R744 refrigeration cycles [3]. To maximize direct power service, the process shoud begin by heating the CO_2, e.g. as in the case of geothermal heating within "Earth Battery", or in the Allam cycle.

There are many paths between pipeline CO_2 conditions and the final state of CO_2 - a lower pressure gas or a product resulting from CO_2 conversion. Opportunities for more research and analysis include determining the most promising utilization pathways suitable for configuration IIB, selecting paths in phase space that accommodate promising utilization pathways and best use available regional resources, and identifying promising storage and storage/utilization hybrid approaches of Type IIC and IIB/IIC.

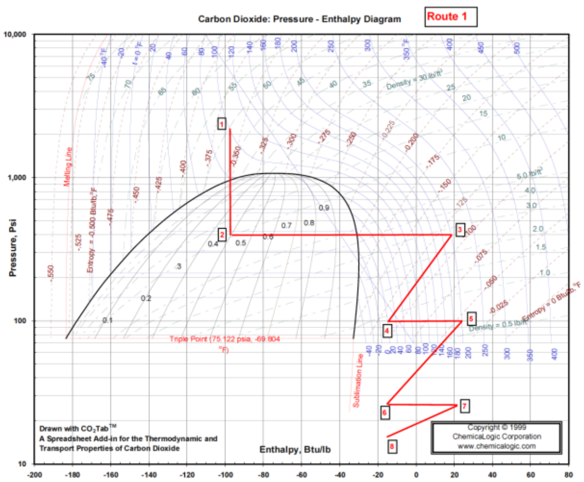

Figure 2: Pressure-Enthalpy diagram for CO_2 with an exemplary path designed to commence cooling before extracting work. (Image: courtesy of Advisian)

2 METHODOLOGY & RESULTS

This section describes the approach used to evaluate the addition of a CDES system to a conventional electricity generation plant. The approach extends the cost and performance methodology used in the NETL Cost and Performance Baseline for Fossil Energy Plants, and incorporates the Cost Estimation Methodology for NETL Assessments of Power Plant Performance.

To serve as a starting point, the entity receiving CO_2 for work and cooling service was selected to be a Natural Gas Combined Cycle (NGCC) plant, NETL Case B31A. To ensure that changes to cost and performance are reflected accurately, NETL Case B31B was used in conjunction with Case B31A to validate the methodology. Table 1 presents results indicating that DOE/NETL guidelines were accurately implemented before the modification described herein. The reader is referred to NETL documentation for more detail about the finacial model, capital structure, and other parameters [4].

		COE [$/MWh] *excl.* T&S		COE [$/MWh] *incl.* T&S	
Plant	Case	NETL	Present	NETL	Present
NGCC	B31A	57.6	57.62	57.6	57.62
NGCC w/ CCS	B31B	83.3	83.26	87.3	87.21

Table 1: Summary of NETL Cases examined

2.1 Power Markets

In a power market, the COE is associated with the supply function of the individual power plant. The COE is the lowest price at which the plant is willing to sell energy and thus it directly impacts the capacity factor of the plant. Hereafter, it is referred to as the minimum sales price offer (MSPO) for the plant. Actual power markets are complex and may require the plant to bid energy using cost-based supply offers that exclude some elements of cost. These complexities are avoided within the present study.

To attain a better understanding of operating and investment decisions in current power markets for the plants considered, a set of synthetic power markets were constructed in a simplified way. First and with respect to NETL Case B31A, a market clearing price (MCP) distribution was formed such that a plant having a MSPO of $57.62/MWh would attain a capacity factor of 85% as measured by the area under the distribution function to the right of the MSPO (Market-iii, Figure 3). Two additional markets were constructed for analysis so that the price range of current power markets is represented. Market-i closely represents a price range observed within PJM's area of service.

A key underlying assumption is that the introduction of the plant or its capacity expansion into the synthetic market would not alter the MCP distribution – this assumption allows the bypass of aggregate supply and demand function analysis. It is assumed that the plant dispatches whenever the MCP is above the MSPO.

Figure 3 shows how the MCP distribution affects the choice of operational mode. In most of the synthetic markets considered herein, the preferred operational mode is to maximize capacity factor, which is restricted to a maximum of 95% in the present analysis. In the lowest-priced synthetic market, the plant maximizes financial performance by operating below its maximum possible capacity factor (it operates at 87%), as the benefits of selling lower-priced energy cannot justify the costs. Market-i does not allow an IRROE greater than 10.70%.

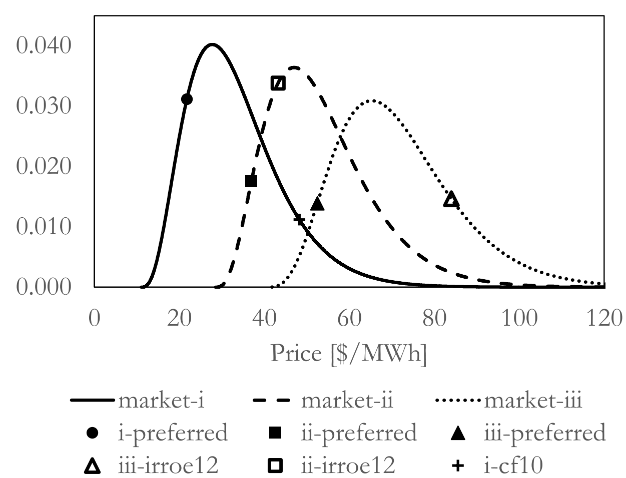

Figure 3: Market clearing price distributions for three synthetic markets (i, ii, and iii) and different operational states for a hypothetical NGCC electricity generating station, Case B31A. The point "i-cf10" shows the MSPO assocated with a capacity factor of 10%.

2.2 Power Enhancement by means of CDES

To understand the potential of using pipeline CO_2 to boost the performance of a B31A plant, a version of the path in Figure 2 was examined in a preliminary screening conducted by Advisian / WorleyParsons. The system considered may be classified as Type IIA, and is referred to as Case IIA. Performance enhancement in Case IIA occurs as a result of CO_2-based cooling and work, consistent with the process in Figure 2. Preliminary results are shown in Table 2.

Plant Performance Comparison		B31A	B31A*	Case IIA
Air Temperature	°F	59	90	90
Net Power Output	kW	630,000	586,518	654,051
Enhancement in Output	kW			67,533
Net Fuel Input, LHV	kW	1,105,162	1,040,978	1,190,236
Net Plant Heat Rate, LHV	BTU/kWh	5,990	6,056	6,209
Efficiency	%	57.00	56.35	54.95
CO_2 Consumed	tonne/MWh	-	-	4.35
Additional Fuel Consumed	MMBTU/MWh	-	-	7.54

Table 2: Performance of Cases B31A and IIA at an off-design air temperature

The primary effect of using CO_2 in this case is the cooling of inlet air to the combustion turbine, counteracting the performance decay resulting from the lower air density on hot days. This is only one mode of operation and is most suitable for hot and humid climates, e.g. June-September in Dallas (TX), April-October in Laredo (TX), and at least July-October in Phoenix (AZ).

Table 2 shows that plant B31A loses approximately 6.9% of its net power output (43.5 MWe) when the air temperature increases to 90°F from the design-point temperature. By implementing CO_2-based cooling and work service in a path that is consistent with Figure 2, an enhancement of 67.5 MWe in net power output can be attained relative to the state of diminished performance (B31A*). This would boost the plant output above the original design point, producing more power but forcing the combustion turbine to operate at less efficient rotation rates.

2.3 Financial Performance

To measure and optimize the plant's financial performance, the unlevered free cash flow (FCF) to the firm was selected. The internal rate of return on the unlevered FCF, hereafter "IRR(FCF)", is the primary financial metric in this analyis.

It was assumed that CDES is compensated at least similarly to the base plant as they co-operate in Market-i. The capacity factor for this auxiliary system depends on other fixed and variable costs as discussed herein.

Additional power market assumptions that are relevant to assessing the economic value of the CDES approach used in Case IIA: (a) the value of deferred transmission and distribution is \$500/kW/yr, (b) capacity auction revenue is \$150/MW/day, and (c) non-spinning reserves revenue is \$6/MWh. All value/revenue streams are scaled by the capacity factor of the CDES system. Revenues for (b) and (c) enter the financial statements in a conventional way.

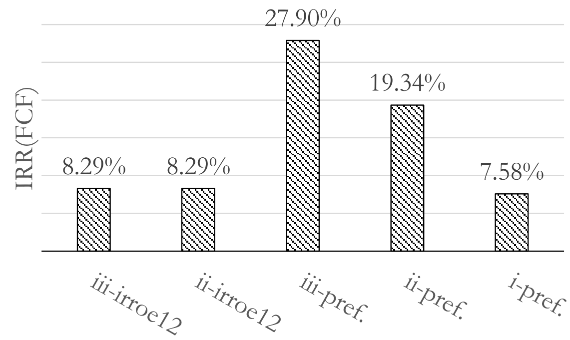

Figure 4: Internal Rate of Return (IRR) on the unlevered free cash flow (FCF) to the firm for the operating states of plant B31A that are indicated by the symbols in Figure 3.

The value of deferred transmission and distribution (T&D) is accounted for the CDES system indirectly: the value of deferred T&D is recognized as a debit to intangible assets with a concurrent credit to retained earnings; additionally, by providing CDES service, the statement of cash flows reflects increased operational cash flow in the amount of the debit.

The base plant, B31A, only earns energy revenues within Market-i. The aim of the utility company in deciding on a CDES system would be to improve financial performance by a number of basis points above an IRR(FCF) of 7.58%. It is assumed that 60- and 100-basis points enhancement are significant enough to influence major investment decisions on basis that 60 bps signifies the difference between 30-year Treasury bonds and 10-year Treasury notes; and 100 bps signifies the difference between 30-year bonds and 5-year notes, at the time of writing this paper.

Figure 5 shows the required minimum capacity factor needed by the CDES system in Market-i in order to attain the specified basis-point enhancements to IRR(FCF).

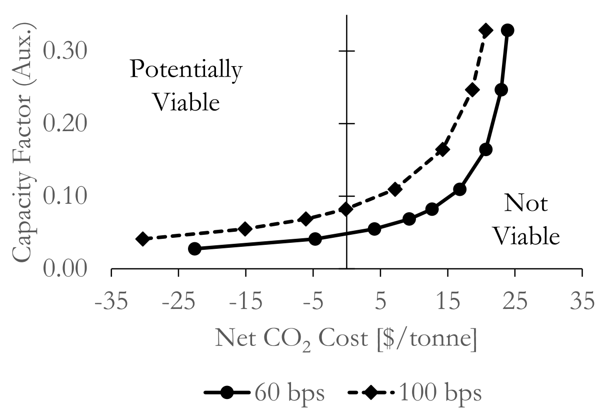

Figure 5: Minimum capacity factor of the CDES system and key variables affecting its ability to realize a 60- or 100-basis points (bps) enhancement of IRR(FCF) for a modified B31A plant in Market-i.

The principal variable in Figure 5 is the net cost of CO_2, defined as the price paid (or cost to produce) less any utilization revenues or associated tax credits.

With reference to hypothetical CDES systems having to operate with a net CO_2 cost of $7.17/tonne and needing to attain a 100 bps enhancement over plant B31A in Market-i; the "capital-free" system would need to operate at a 11.0% capacity factor and is represented by a point on the upper curve in Figure 7; and a $50 million system would need to operate at a 21.1% capacity factor and would be located within the "potentially viable" area above the upper curve in Figure 7.

Looking further into these hypothetical examples reveals that the primary driver for an investment decision is the value of deferred transmission and distribution infrastructure, at least in synthetic Market-i. Capacity auctions and operating reserve revenues are inconsequential. Figure 6 illustrates the contributions of CDES attributes to overall IRR(FCF).

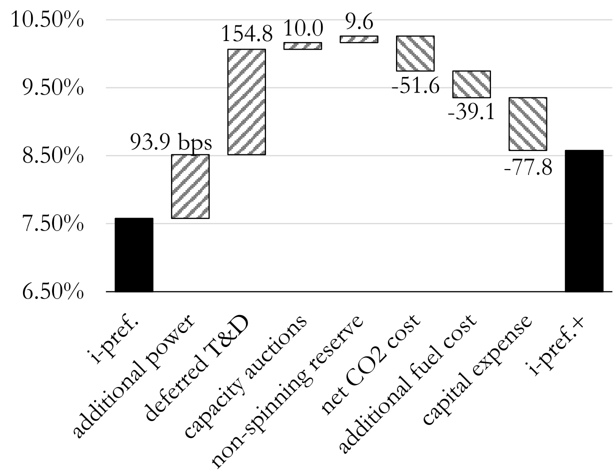

Figure 6: Contributions of the CDES system attributes to the overall change in plant IRR(FCF), summing to total of 100 basis points (bps) enhancement over the original state that is preferred by plant B31A in Market-i. Total capital expenditure for is assumed to be $50 million.

The decision to deploy an auxiliary CDES System will depend ultimately on the competing alternatives. A relevant benchmark is the expansion of the original NGCC plant so that it provides the same amount of additional power as the CDES System that has been considered in this study (67.5 MWe, Table 2).

To compare CDES to a greenfield plant expansion (oversizing) scenario, the B31A plant output and costs were scaled up using a scaling factor approach. Figure 7 shows the resultant IRR(FCF) and additional total overnight costs (TOC) over the original Case B31A.

Figure 7 suggests that a conventional plant expansion by the same capacity as the considered CDES system (67.5 MWe) would only attain a 31 basis point enhancement to the plant's IRR(FCF). For the sake of presenting a fair comparison; the value of deferred T&D, capacity auction revenue and operating reserve revenue were not granted to this expansion.

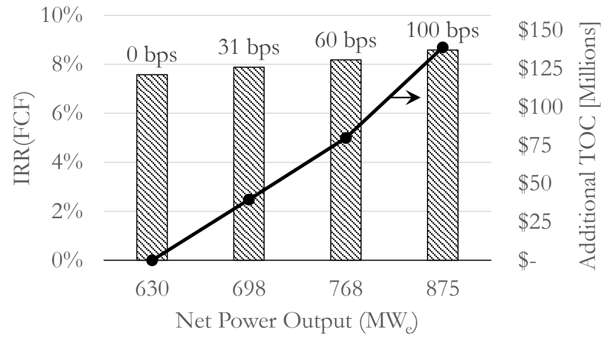

Figure 7: Power plant expansion (greenfield) as an alternative to CDES capacity

Figure 7 suggests that to attain a 100 basis point enhancement to the plant's IRR(FCF), an additional $139 million of Total Overnight Costs are required. Further analysis is needed to identify utilization pathways that reduce the net CO_2 cost to a workable range in Figure 5.

3 DISCUSSION

There are many approaches to CDES. The most valuable approaches would provide the value of deferred transmission investment, in addition to serving energy to load centers and providing reliability services. The key challenge is overcoming the cost of CO_2, which is offset-able by utilization revenues or by returning the CO_2 to the pipeline infrastructure – both approaches require addition of energy that can be removed from the grid in times of excess, and thus serve as a battery that takes and gives power. CCS is a key component of such a battery.

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4 REFERENCES

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