Engineering and Design of an Integrated Thermal Storage and Carbon Capture System on Calpine's Delta Energy Center

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Abstract

The United States electrical grid has begun transitioning towards lower-carbon energy sources increasingly through the implementation of variable renewable energy (VRE) sources such as solar and wind power. Fossil fuel power plants, such as combined-cycle gas turbines (CCGTs), have responded to this energy transition by increasing their responsiveness to electricity prices and becoming less base loaded. As carbon capture on these power plants becomes necessary to attain a net-zero electrical grid, further research is needed to determine how to most economically couple these carbon capture plants to the cycling fossil fuel power plants in an electrical grid with high VRE penetration.

Previously, ION Clean Energy (ION) teamed with Colorado State University, Storworks, and the University of Pennsylvania to develop a technoeconomic framework for a thermal storage system on a CCGT facility with ION's ICE-31 carbon capture solvent. The hypothetical greenfield power plant was optimized across several future electrical grids with different price signals depending on VRE penetration. The carbon capture unit was optimized against different carbon tax signals, resulting in optimal capture efficiencies between 98.0% and 99.2% depending on CO_2 tax rates and anticipated CCGT capacity factor. The team also optimized several thermal storage schemes, with the most promising technology being the Storworks Power concrete thermal energy storage (TES) design using resistive heating. This added up to \$40M to the net-present value (NPV) of the greenfield base facility over its 30-year life.

Based on the strong economics and simple design of Storworks Power concrete TES, ION has partnered with Calpine as a host site to provide a sensitivity for TES addition on a Front-End Engineering and Design (FEED) study at Calpine's Delta Energy Center. The study is still ongoing, but the results will evaluate the feasibility for the TES design using current and future price signals from the California Independent System Operator (CAISO). The capital cost for all major equipment and its installation will be estimated at an AACE Class IV level. Annual operating costs will be determined based on electrical price signals, thermal storage volume, and maximum power draw/discharge of the unit. In addition, the necessary Balance of Plant tie-ins to integrate the thermal storage with both the CCGT facility

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(electrical connections for power draw) and carbon capture facility (steam connections for thermal discharge) will be incorporated. The operating and capital costs will enable comparison against batteries as another power storage technology under Calpine's consideration across its California fleet. The FEED study will inform Calpine as they make investment decisions on carbon capture facilities with and without thermal storage throughout their CCGT fleet.

This study presents the results of an initial economic assessment of the proposed TES system. The study shows a significant positive NPV in the CAISO grid where there are large incentives for delivering Net-Zero electricity, plentiful and hours-long periods of negative electricity prices, and high demand for electricity when VRE units cannot fulfil the electrical load.

Keywords: Thermal Storage, Electrical Grid Optimization, Post-combustion capture of CO_2; Front End Engineering and Design; Deep decarbonization;

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1. Introduction

The United States (U.S.) electrical grid has begun transitioning towards lower-carbon energy sources through the implementation of variable renewable energy (VRE) sources such as solar and wind power. This trend is already observable in data on annual generation [1] and is projected to continue [2]. Combined-cycle gas turbines (CCGTs) can play an important role in providing *dispatchable* power to the grid when renewable generation is not sufficient to meet demand. However, CCGTs will need technologies like Carbon Capture and Storage (CCS) to reduce their associated carbon dioxide (CO_2) emissions. Additionally, the variability of renewable electricity generation has resulted in a more volatile price environment. There are very low or even negative prices during periods of renewable overgeneration, followed by high prices during times when demand exceeds renewable generation. CCGTs equipped with CCS may need new technologies to improve their economic performance in this volatile price environment associated with high VRE electrical grids.

In previous studies, collaborators at Colorado State University (CSU), ION Clean Energy (ION), the University of Pennsylvania, and Storworks Power proposed hot thermal energy storage (TES) as a candidate technology to improve the viability of CCGTs with CCS. A techno-economic model was developed for the proposed system and applied to the CCGT plant described in National Energy Technology Laboratory (NETL) Case B31B [3,4]. The proposed technology concept is shown in Figure 1. An air blower circulates air through the system in both the charge and discharge modes. In charge mode, the air is blown through an electric resistive heater to be heated, and then flows to the concrete TES unit to transfer heat to the concrete via holes in the concrete blocks. During discharge mode, the air flows to the now hot concrete to receive the stored heat, and then passes through a steam-generating heat exchanger to produce steam to be delivered to the CCS system. An economic decision support tool was developed that models the technology in a proposed price and policy environment to determine its economic value. The tool also conducts control co-design (CCD) optimization to determine the optimum technology configuration to achieve the highest economic impact [5]. The prior work identified the Storworks Power electric-resistance heated concrete TES as a favorable technology that added value in 12 of 14 projected future price environments [4].

While the initial results were promising, there were limitations in the work up to that point. First, the work primarily modeled government policy as a carbon tax, rather than a carbon credit, which is the actual policy in the U.S. today. Second, the studies did not assess the impact that capacity reserve payments might have on TES's economic performance. Third, the studies were run using projected future price profiles [4] or now out-of-date real location marginal prices (LMPs) [6], and the design was not targeted to a real facility. Finally, the technology cost estimates used were early estimates and not based on detailed engineering or Association for the Advancement of

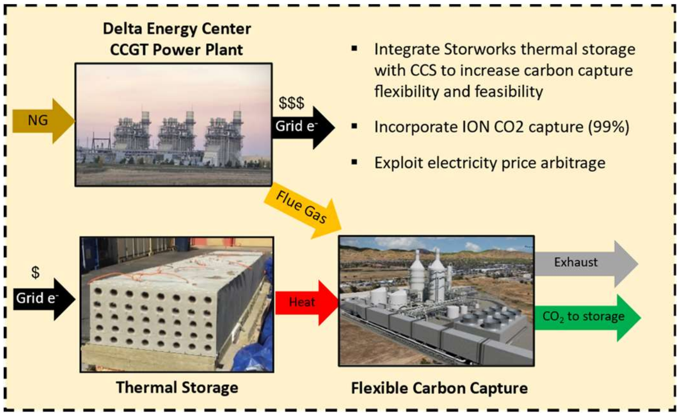

Figure 1. Proposed hot Thermal Energy Storage design concept in charging and discharging modes.

Cost Engineering (AACE) standards.

To address these limitations, an ongoing Front-End Engineering Design (FEED) study of an ION CO_2 capture system for Calpine's Delta Energy Center (DEC) has been expanded to include a Storworks Power TES system. The objective of the new study is to understand the cost, performance, economic value, and lifecycle CO_2 impact of the proposed TES addition to the project. The capital costs for the project will be estimated at an AACE Class IV level. The cost estimates will also include auxiliary equipment to enable integration of the TES unit into the plant, including electrical connections for power to the TES and steam and boiler feedwater connections between the CCGT, CCS, and TES.

While the effort is ongoing, this work presents the results of an initial economic assessment that has modeled the TES technology in the price and policy environment at the DEC. The purpose of the initial assessment is to identify the best TES configuration (storage duration and charge ratio) to use for the broader FEED study.

2. Methodology

2.1. Integrated Modeling Approach Overview

For this study, the team utilized a mostly similar integrated modeling approach as prior studies [4-6]. An overview of this approach is shown in Figure 2. First, the technology is represented by a technology model that calculates component-level thermodynamics for the entire system, including the CCGT and TES. The CCS is represented by total energy demand rather than component-level analysis, due to the proprietary nature of the system. The technology model was developed in Engineering Equation Solver and is based on the NETL's cost and performance baseline Case B31B [3]. For the Delta project, the technology model was scaled to match the Delta CCGT facility. Cost and performance data for the CCS system was provided by ION. Cost and performance data for the TES was provided by

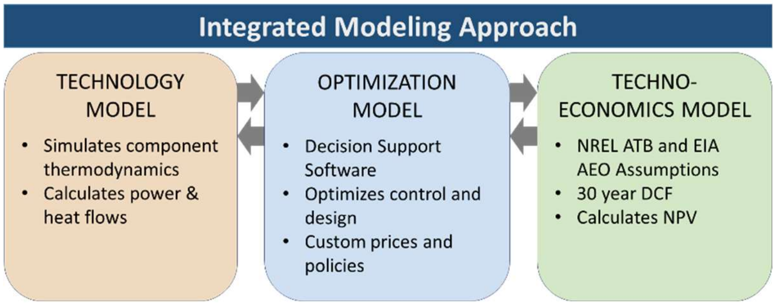

Figure 2. The integrated modeling approach first developed for the ARPA-E FLECCS Program was utilized for this study.

Storworks Power. More details on the formulation of the technology model can be found in Markey et al. [4].

Second, the optimization model is a custom-built MATLAB codebase developed to perform control co-design (CCD) optimization for a TES combined with a CCGT+CCS plant. The software is composed of an inner control optimization loop and an outer design optimization loop. The inner loop optimizes control of a proposed TES design to produce the highest annual profit. The outer loop uses a pattern search algorithm to identify the possible designs that return the highest net present value. The optimization model is capable of taking custom electricity and natural gas prices and is typically fed 8760-hour (year-long) price sets from predicted future markets or real independent system operator (ISO) pricing. The optimization model also reports out important values, such as component capacity factors, annual costs and revenues, and direct CO_2 emissions from the combustion of natural gas.

Finally, the techno-economics analysis (TEA) model is also a MATLAB program that conducts a discounted cash flow (DCF) analysis of the proposed system. The TEA model receives capital costs and cash flows from the optimization model and constructs a 30-year DCF. The model uses updated standard assumptions from the National Renewable Energy Laboratory (NREL) 2024 Annual Technology Baseline (ATB) [7] as well as the Energy Information Administration (EIA) 2023 Annual Energy Outlook [2]. The economic assumptions utilized for this study are shown in Table 1.

Table 1. Financial assumptions utilized in the techno-economic model.

Financial Assumption	Value	Units	Source
Inflation	2.5	%	[7]
Loan Interest Rate	8	%	[7]
Loan Term	30	Years	[7]
Financed Amount	55	%	[7]
Equity Amount	45	%	[7]
Construction Interest Rate	7	%	[7]
Construction Period	3	Years	[7]
Construction Build Rate	30, 60, 10	%/Year	[7]
MACRS Depreciation Schedule	20	Years	[7]
Tax Rate (combined State and Federal)	27	%	[7]
Internal Rate of Return	10.5	%	[7]
Annual Natural Gas Price Increase	0	%	[2]
Annual Electricity Price Increase	2.0	%	[2]

For the Delta Project, several updates were needed within the integrated modeling approach. Each update will be described in the subsequent sections.

2.2. Implementation of Section 45Q Tax Credit for Carbon Sequestration

Previous studies modeled simple carbon taxes, where a penalty was owed for each ton of CO_2 directly emitted from the combustion of natural gas in the CCGT. This penalty was imposed for the entirety of the DCF analysis period. This simple carbon tax model is different from the actual U.S. Internal Revenue Service Section 45Q tax credit in two important ways. First, the 45Q Tax Credit is only available for 12 years [8], so this must be accounted for in the model. Second, an impact of the credit rather than a penalty is to change the breakeven point for CCGT plant operation. This causes optimal plant and TES control to be different during the years the credit is available versus the years after it has expired. These two things together mean that a true 30-year DCF evaluation must account for the unique optimal operation during the credit years and the non-credit years.

To this end, we modified the existing optimization model to have support for multiple distinct periods of operation. The implementation of this change is shown in Figure 3. Inside the inner control loop, two unique periods are optimized for maximum annual profit with and without the 45Q tax credit. The amount of tax credit is calculated based on the credit value of \$85/t CO_2 multiplied by the amount of CO_2 sequestered during the period of operation. The Net Present Value (NPV) is calculated from the outputs of each period and communicated to the outer design optimization loop. The outer design optimization loop then conducts a pattern search to maximize the two-period NPV.

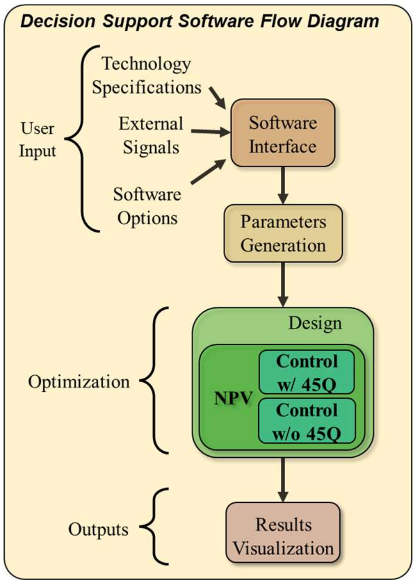

Figure 3. Decision support software with implementation of two period support.

2.3. California Air Resources Board AB32 Cap-and-Trade

The Delta Energy Center is located in California and is therefore subject to the California Air Resources Board AB32 Cap-and-Trade policy for CO_2 emissions for electrical distribution utilities. This policy restricts the amount of CO_2 that can be emitted by the sector, and then creates a marketplace for buying and selling the rights to emit. Since it is difficult to project trading prices in the future, an average of recent trading values was utilized. The average trading value from the prior four quarters (2023Q4 to 2024Q3) was calculated to be \$36.94/t CO_2 [9]. The AB32 policy is then represented as a simple tax. The tax value is multiplied by the CO_2 emitted during the period and rolled into the DCF analysis in the inner loop.

2.4. California Public Utilities Commission Resource Adequacy Payments

Another policy relevant to power plants operating in California is the California Public Utilities Commission Resource Adequacy program. The program was established to ensure reliability of the grid, especially as renewable energy production increases. The program creates a payment mechanism for available dispatchable capacity of a power plant, and it is also applicable to energy storage assets. The most recent trading values in the program based on the 2022 annual report were \$7.68/kW-month [10]. In the model, the CPUC capacity payment was represented as a fixed revenue equal to the product of the payment value multiplied by the neutral net power of the CCGT plus the additional power achieved during TES discharge. The CPUC program requires 8 hours of discharge capacity for storage assets to qualify, so for TES configurations less than 8 hours, the boosting power was excluded from the calculation. This fixed revenue is then input to the inner loop DCF analysis.

2.5. Electricity and Natural Gas Prices

The project sought to assess the value of TES technology in real markets, so historical electricity LMPs from the California Independent System Operator (CAISO) were utilized in the analysis. The three price nodes assessed were TH_SP15_GEN-APND, TH_NP15_GEN-APND, and DELTA_2_PL1X4-APND (abbreviated as SP15, NP15, and DELTA). CAISO real-time market 5-minute prices were obtained and converted to hourly average prices for use in the model. Prices were obtained using the GridStatus library v0.27.0 in Python [11]. For this study, we analyzed prices from 2020-2023, though complete 2020 data for DELTA was not available. DELTA is specific to the proposed project location. SP15 and NP15 are generalized prices for southern and northern California, respectively. These prices were included to help understand how the DELTA node compared to the state more broadly. SP15 is of particular interest because it has a higher level of renewable generation, and therefore it may be predictive of how DELTA could look in the future if renewables increase there. A comparison of DELTA and SP15 average hourly prices for April and August is shown in Figure 4.

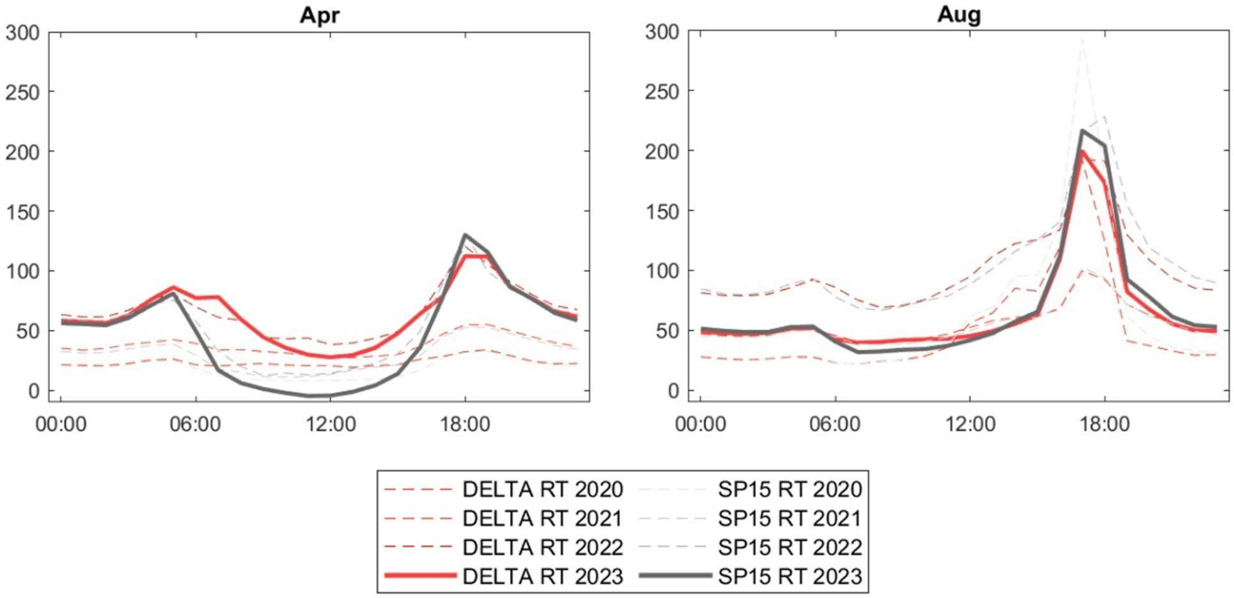

Figure 4. Comparison of CAISO hourly real time prices by month for April and August

For natural gas prices, Citygate Prices for California were obtained from the EIA Natural Gas data browser [12]. The gas prices are year-matched to the CAISO LMPs.

3. Results and Discussion

The integrated model was run for all the price profiles with and without TES. First, the model was run with a fixed nominal design of 8 hours of storage and a charge-to-discharge rate ratio of 1. Next, the model was run in full design optimization mode in order to determine the optimum design configuration for each of the price profiles. The results are shown as the difference in NPV attributed to adding the proposed TES system to the CCGT+CCS plant (where a positive difference represents an improved NPV). The results are shown in Figure 5. The columns show NPV differences, and the capital cost of the proposed TES system is shown as an overlayed scatter plot using a common axis. Comparing the column and scattered diamond in each price scenario can indicate the approximate relative return on investment in each case.

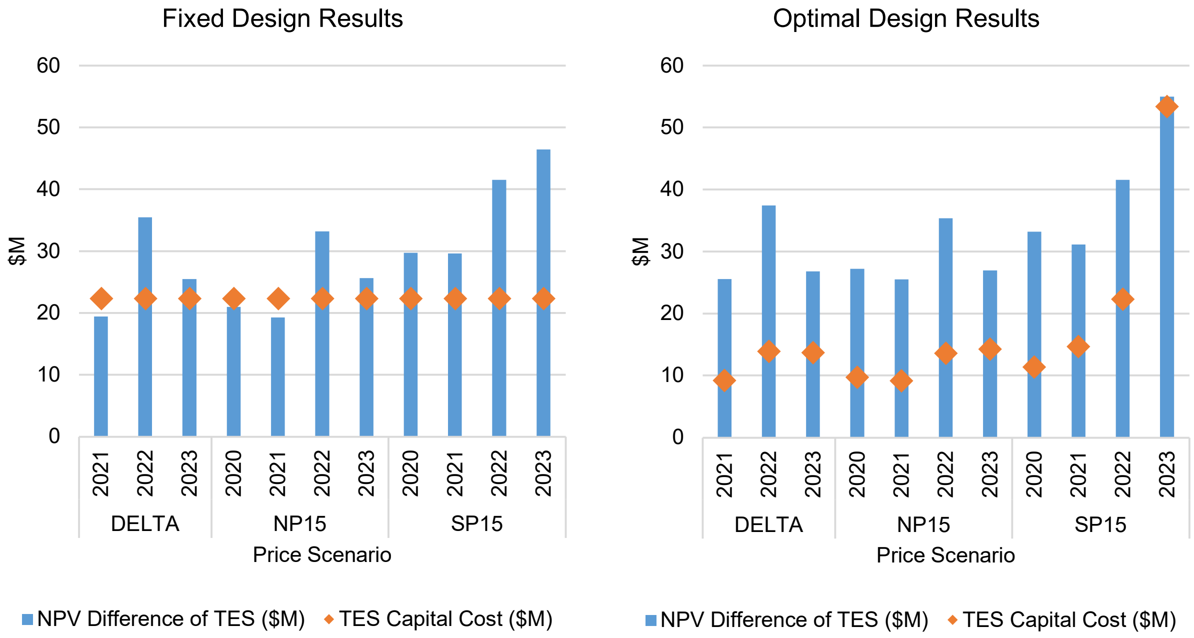

Figure 5. NPV difference of adding TES to the CCGT+CCS system with fixed and optimal designs.

The first conclusion to be drawn from Figure 5 is that the TES technology had a positive economic impact on the CCGT+CCS system in every price scenario that was modeled, even with a non-optimal design. This result makes intuitive sense because the value of resource adequacy payments in California is quite high. The nominal design has a discharge capacity of 44.9 MW, which earns approximately $4.1M per year in capacity payment revenue. Even when discounted, the NPV of this revenue stream helps justify the capital cost of the system. Additional revenue is available from performing electricity price arbitrage, and the varying level of arbitrage opportunities across price sets likely explains most of the variation across the scenarios.

The next conclusion to be drawn from Figure 5 is seen when comparing the Fixed Design Results to the Optimal Design Results. In high variability markets like SP15 during 2023, additional NPV benefit is available through design optimization; however, this benefit comes at an additional capital cost. In lower variability markets, additional NPV benefit is achieved largely through minimizing the capital cost to ensure only the optimum charge rate and capacity are built. To give a more detailed view of the design optima, the resulting values for TES storage duration and charging ratio are shown in Table 2. Implementation of the CPUC resource adequacy payment has led to a strong effect on storage duration. No case shows an optimum value lower than the minimum to qualify. Therefore, the primary change in the optimum design for each case is the charging ratio. As in previous studies, markets with long periods of low prices can see NPV improvement by reducing the size of the resistive heater used to charge the TES. However, in markets with high variability, like SP15 RT 2023 which has many periods of negative prices, more NPV benefit can be obtained by oversizing the heater. This increased charging ratio allows the TES to provide a valuable service to the grid by absorbing renewable overgeneration that would otherwise be curtailed. Notably, the optimum charging ratio has roughly increased over time in all regions, indicating that as renewable generation share increases in a region, a larger TES system becomes more valuable.

Table 2. Optimum design parameters for each price scenario

CAISO Node	Year	TES Duration (hours)	Charging Ratio (charge rate/ discharge rate)
DELTA	2021	8.0	0.08
	2022	8.0	0.41
	2023	8.0	0.39
NP15	2020	8.0	0.12
	2021	8.0	0.08
	2022	8.0	0.39
	2023	8.0	0.44
SP15	2020	8.0	0.23
	2021	8.0	0.46
	2022	8.0	1.00
	2023	17.5	2.50

The next results plot in Figure 6 shows an example of plant control data from the model. The neutral power of the plant P_{CCGT} is the power delivered to the grid when the TES is neither charging nor charging. The actual power to the grid, $P_{NetGrid}$ is the actual power delivered to the grid after accounting for the TES power draw or boost, depending on the operating mode. The TES charges during low price periods, leading to a decreased $P_{NetGrid}$. Then, the TES discharges during high price periods, leading to a higher $P_{NetGrid}$. The lefthand plot represents operation when 45Q is available. The policy has the effect of reducing the breakeven price for the plant, causing it to run through periods of relatively low prices. The righthand plot shows the plant operating during the same prices, but without the 45Q tax credit in place. In this case, the plant shuts down during periods of low prices. The TES can perform price arbitrage in either scenario, because charging occurs independently of the CCGT operating state. However, the total costs and revenues will be different depending on the tax credit scenario, which reinforces the need to implement two-period evaluation to accurately assess the value of the TES and CCS technologies.

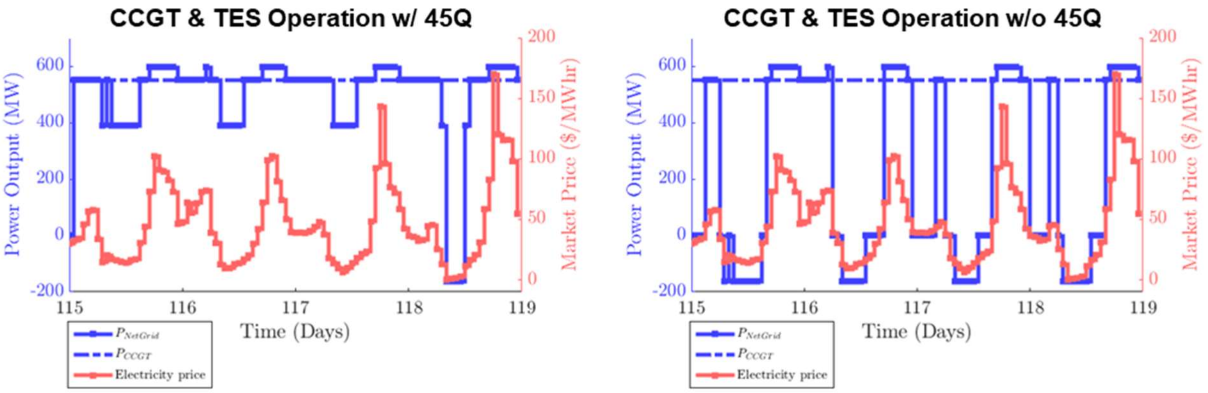

Figure 6. Plant operating power versus LMP, with and without the 45Q tax credit.

4. Conclusion

This study presented an update to previously published work assessing the economic performance of thermal energy storage for CCGT+CCS systems. The methodology has been updated to provide improved accuracy for the assessment of the proposed technology at Calpine's Delta Energy Center in Pittsburgh, CA. The initial economic assessment has been completed and shows positive economic impact for adding TES in all scenarios modeled. This work will inform the ongoing FEED study, and the next steps will include updating the assessment with AACE Class 4 cost estimates for the system. The project is expected to conclude in early 2025. Future work should also investigate any commercial or contracting constraints related to participation in ISO markets as both generator and consumer. Overall, this study has shown that TES can add economic value to CCGT+CCS systems and that decision-support software utilizing various models can increase the understanding and profitability of emerging technologies.

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