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Solar Thermal Hybridization of Utility Steam Systems in Oil and Gas Facilities With CST, A Solution for Decarbonization

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Abstract. The Hybridization of steam utility systems in oil and gas facilities with concentrated solar technology (CST) has been an untapped area for Decarbonization. The high capex involved with with high-reliability risk perception, has prevented these solutions from being implemented, even at the pilot level. However, as environmental policies are affirmed, deploying these solutions can become a reality, tangibly demonstrating the technology's performance and reliability. The result of a Solar Thermal Technology (STT) Integration is a master/slave configuration where the solar-based steam replaces a portion of the existing boiler system production, decreasing the fuel cost for the industrial facility. This paper discusses some techno-economic aspects related to the Hybridization of utility steam systems with an CST. It also presents an optimization tool described as Combined Heat and Power (CHP) Optimization, which is applied to an existing steam network in preparation for a solar thermal technology integration simulation. A sensitivity analysis on the NPV is done based on a range of capex, fuel prices, and Decarbonization revenues to help understand these variables' impact on the overall economic feasibility.

Keywords: Hybridisation, Decarbonization, STT Integration

1. Introduction

The hybridization of steam utility systems in typical oil refineries with solar thermal energy has been an untapped area of decarbonization. Hence, knowledge gaps exist in these solutions' actual technical and economic realities. The high capex required and low fuel gas prices are a barrier to implementation. In addition, the operational and reliability risk perception by operations, engineering, and maintenance (OME) teams is high, especially in complex oil and gas facilities. Nevertheless, the opportunities to decarbonize these facilities are unprecedented and can only be realized with a logical sequence of solutions that vary in cost and complexity. Integrating expensive renewable heat as a brownfield project should be done when the facility runs with minimal losses. Otherwise, the potential for a failed integration increases, reinforcing the negative perception of these solutions. Irrespective of any solution, the operation of the utility steam system has to remain reliable and flexible for continuous hydrocarbon processing. This reliability stems from many aspects of asset management, one resulting from a redundant steam production capacity with enough reserve to meet the demand under a range of events. To ensure a successful hybridization of a steam network, a holistic approach is required where considerable evaluation is given to the steam utility network, the solar technology, cost metrics at the plant level, and the decarbonization objectives.

2. CST Integration Process

For complex utility systems, where the steam is supplied by boilers, process heaters and co-generation units, a rigorous optimization is required before considering STT as an additional thermal conversion technology. Most of the time, energy represents the largest operating expense incurred by an oil and gas facility, usually accounting for half of the total operating cost [1]. Refineries can lose energy in the order of 10-20%, through inefficient configurations and equipment, leakage, waste, poor controls, etc [2]. These inefficiencies become more critical during periods when energy prices soar affecting the bottom line. Once corrected to minimize energy losses, the integration of STT for process heat can occur as a final decarbonization solution.

A CHP Optimization Model is based on mathematical and thermodynamic representations to detect inefficiencies and opportunities to optimize complex steam utility systems. Under a “no excess steam” philosophy, the objective is to maximize cogeneration units, reduce boiler load, and practice dual motor/turbine switch-ability to optimize the energy utilization. Under this patented platform, the site utility system can be analysed with the steam contribution of a specific STT and develop hybrid modes of operation to reduce the boiler utilization. The evaluation of how much and where to integrate the solar steam needs to be an iterative process to result in a seamless and smart integration to create the best economic outcome.

A seamless Integration ensures the solar steam injection will have no adverse effects on the steam users or create steam unbalances. This is achieved by guaranteeing the quantity and quality of the solar steam matches the steam requirements and conditions (temperature and pressure) at the respective header connection. Technically this is possible with the appropriate sensor and control system technology. A smart integration requires a good evaluation of the the solar technology performance, optimizing the field configuration to the annual site’s DNI. This ensures higher outputs with less capex, maximizing fossil fuel savings and overall returns.

An existing steam network is best hybridized energy-wise when high enthalpy solar steam is fed into the corresponding HP or MP steam headers. Solar concentrator systems such parabolic trough or Fresnel systems are best suitable for this, especially in areas with annual DNI ranging from 1900 kWh/m^2 to 2300 kWh/m^2 [3]. LP steam applications or adding sensible heat to boiler feedwater system for example can be served by other STTs with operating temperature limits for this range in areas with lower DNI.

From an operational standpoint, the integrated mode of operation requires a joint modulation of the boiler(s) and STT working in a parallel arrangement to supply the required steam. Depending on the configuration (thermal storage/no storage) and due to the intermittency of solar resource, aspects such as steam reserve and availability could be based on the boiler capacity assets and/or in the solar storage capacity.

Lastly the economic feasibility of the installation has to be proven. This is a function of different critical technical variables that can move the NPV in the positive or negative direction. These include DNI resource, capex, opex and replaced fuel. Lastly the carbon offsets can be monetized and factored in to help in the viability of the project.

2.1 Capex Distribution in a Solar Thermal Integration Project

Of special interest is the distribution of capital expenditure in a STT integration. The capex distribution in a concentrated solar power (CSP) plant with a parabolic trough technology and a power block is well known with a good degree of approximation. The power block along with the costs associated with its cooling systems and grid integration would normally represent around 20-25% of the whole capex. The remaining components, which are specifically associated with a solar heat application can be distributed as follows:

1. The solar collectors (40% of CAPEX): This portion is allocated to the construction and installation of the parabolic trough technology.

2. Thermal Energy Storage (20% of CAPEX): This portion is dedicated to building and maintaining the thermal energy storage system. This system uses molten salt or oil as a heat transfer fluid and includes tanks, piping, and control systems.

3. Heat Transfer Fluid Systems (10% of Capex): Approximately 10% of the CAPEX goes into the heat transfer fluid systems, including pumps, pipes, and heat exchangers used to transport the thermal energy from the collectors to the industrial facility.

4. Infrastructure and Site Preparation (5% of Capex): About 5% of the CAPEX is used for constructing access roads, preparing the site, and developing other necessary infrastructure.

5. Control and Monitoring Systems (3% of Capex): A smaller portion, approximately 3%, is invested in control and monitoring systems that ensure the efficient and safe operation of the Solar plant.

6. Environmental and Regulatory Compliance (less than 1% of Capex): Expenses are incurred to obtain permits and meet environmental regulations.

In a process heat integration project, without an electrical power block component, the collectors become the mayor equipment, accounting for roughly 50-70% of the total installed cost. Assuming the total cost of an integration depending on the size of the collector field, will vary from \$1000 to \$2500 per kW with some economies of scale being reached in projects above 50MW, the cost of collector field could range from \$500 to \$1250 per m^2.

3. Overview of Combined Heat & Power (CHP) Solution Applied to STT Integration

This section provides an overview of the CHP model developed for the analysis as explain in reference [4]. A typical CHP system model incorporates various elements of steam, power, water and fuel systems into an overall mathematical thermal model that can be used to meet numerous objectives, such as:

- Identifying opportunities for cost reduction through efficiency improvements.
- Accurate energy cost accounting.
- Evaluating the energy cost impact of proposed process changes on the demand side.
- Comparison of various CHP options during early stages of greenfield projects.
- Comparison of various STT options in brownfield projects or during early stages of greenfield projects.
- Identifying load sharing strategies (e.g., switching between motors and turbine drives, boilers and SST facility)

There is several major equipment represented in the CHP optimization model in Figure 1. It includes boilers, cogeneration units, solar thermal field, process heaters with convection sides producing steam, steam turbines generators, steam turbine drivers and motors drivers with switchable steam turbines driving pumps and compressors, steam and power users, steam system network, reducing stations and de-superheater, fin-fan condensers, deaerators and condensate system. This equipment is normally designed for site-specific conditions but often operate under different parameters due to constraints, different ambient conditions, (especially gas turbines and the STT) and fluctuating demand profiles. The performance curve of each type of equipment is developed based on either design or historical data.

The CHP optimization structure uses a similar approach of solving an Economic Dispatch (ED) problem. While ED can be defined as the method or way of determining the most efficient, low-cost and reliable operation of a power generation system by running the available electricity generation units to supply a given load demand (Allen J. Wood, J.D. Glover, P. Oliveira, Dec 1991). The primary objective of economic dispatch is to minimize the total cost of generation while satisfying the operational constraints of the network and the available generation units.

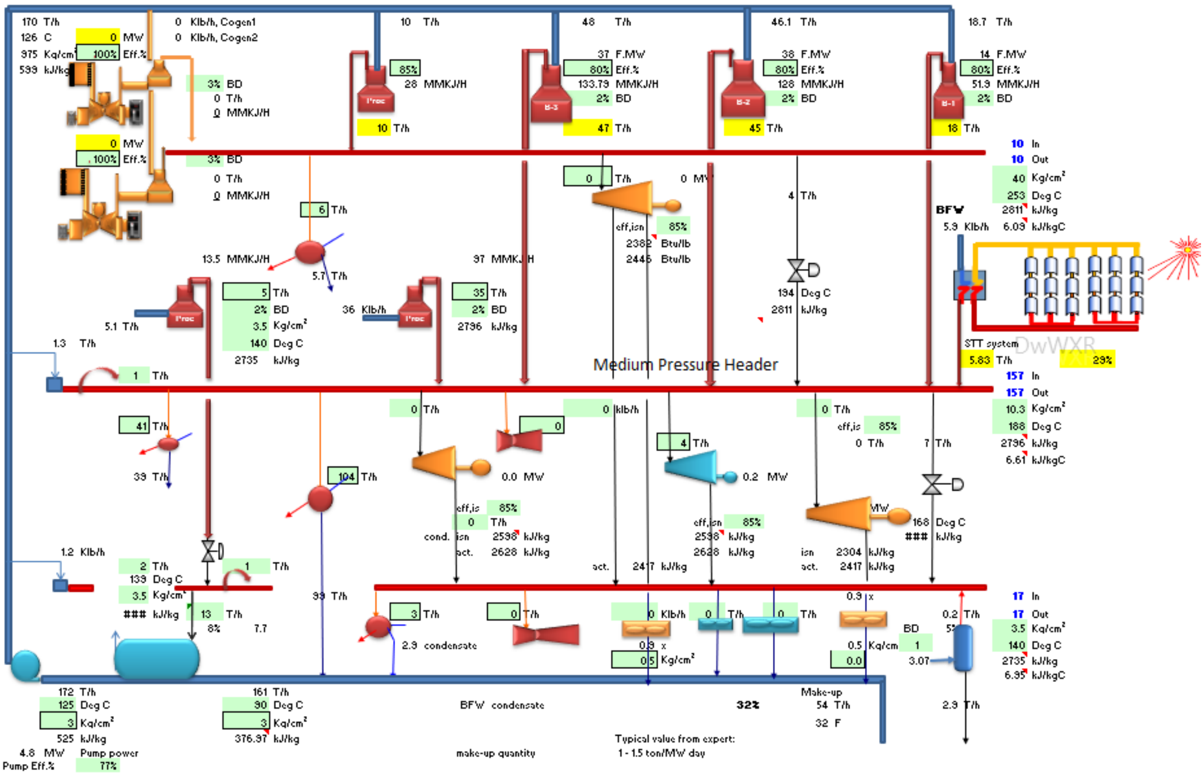

Figure 1. *A CHP Optimization Model, Showing Steam Headers, Produces, Users and a Solar Collector Field.*

In our model, the representation of the optimization structure includes an objective function which is to minimize facility operating cost, which depends on fuel cost, power import and export as well as make-up water and water treatment costs. The variables include steam and power loading of major equipment in the steam systems, including boilers, Solar field, Cogen, STGs and steam turbine drivers. As in any model there are constraints reflected which in this case include:

- Meeting all steam and power demand
- Closing all heat and mass balances
- Maximum and minimum output limitations
- Non-negative flows
- Steam and power reserve required
- Minimum number of running equipment

The main strategy used during development of a typical CHP optimization model is to break down the problem into three levels and solve each step one after another. For this optimization model, the three levels of optimization include power generation optimization, boiler optimization with the solar field production and mechanical driver switch-ability optimization. These levels are shown in Figure 2.

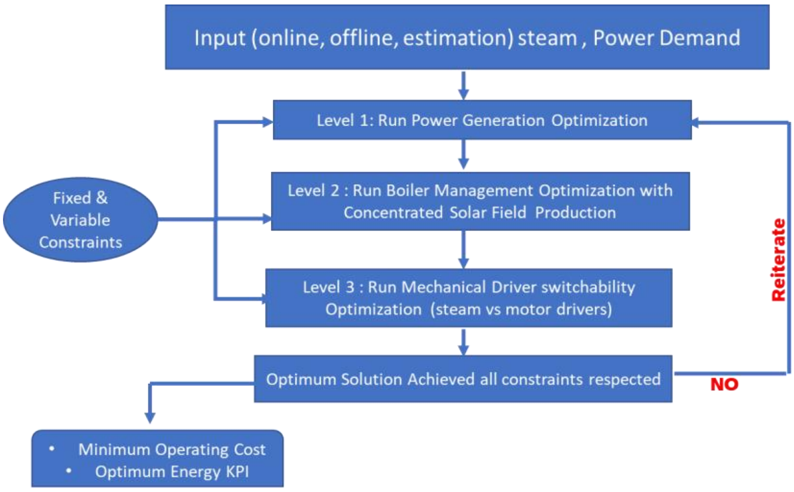

Figure 2. *Optimization Model Levels*

4. Facility Case Study

An oil & gas facility has been selected as a candidate to explore a hybridization of its steam system by integrating a solar thermal field composed of parabolic trough loops. Its steam network, shown in the CHP Model in Figure 1, is driven by three identical fuel-gas fired boilers producing MP steam, each one with a production capacity of 68 T/hr of steam at 150psi and 187C. The steam is used in the process of hydrocarbon refining and also to power mechanical drivers for a number of water pumps, oil pumps and fans.

An initial question to answer is how much solar based steam can be supplied to the existing steam network. This becomes an iterative process and starts by considering a number of interdependent external factors including adjacent land availability, DNI resource quality, type of CST (parabolic trough, Fresnel systems), etc. In addition to these factors, internal aspects inherent to the facility and its steam network will also impose constraints on the final capacity of the solar steam production. Once all factors are evaluated, the final constraint on how much steam can be introduced into the system will be based on the current boiler loading and how much more can it be decreased without impacting operational efficiency. ng efficiency in a noticeable manner. It is a known fact, as a result of internal studies within our wider boiler fleet, that depending on the nozzle's fuel/air technology controls, solid-state sensors and controls without linkage, the efficiency of the boilers is not affected greatly by decreasing its load even down to 30-40% of its design point. This lower range can therefore serve as a limit to the solar thermal steam penetration; i.e. injecting more steam will have a negative impact in the boiler efficiency.

A recent yearly steam production profile of the boilers, Figure 3 is presented with operating limits. The production graphs show two boilers loaded at 55% and 60% respectively from its design capacity. A third boiler is always kept hot ready to ramp up in case needed as steam reserve.

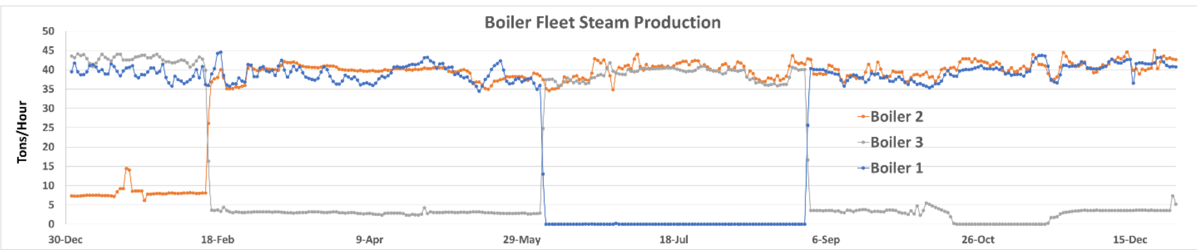

Figure 3. *Boiler load during one-year Operation*

To remain within an efficient boiler operation range, as a starting point, the solar system has been sized to produce 20 T/hr during the day light hours. Based on a daily input of saturated steam of 185˚C at a pressure of 10.5 bar, an annual DNI of 2100 kWh/m², the size of a parabolic trough field using System Advisor Model (SAM) software from NREL [5] resulted in a thermal capacity of 39MW. In this specific solar thermal scenario, no thermal storage was contemplated. The PTC solar field was circulating Therminol VP-1 as HTF at 255C at design conditions for 7hrs and configured with 36 loops of 1728 SCE - ET150 / Schott PTR 70.

Behind the CHP optimization model are a set of mathematical equations in Microsoft Excel representing the process of the steam system. Additional variables related to the solar thermal integration have been added to the model equations. The concept of simultaneous process and utility design optimization was developed and used for the optimization. In references [6], [7], the techniques used in optimizing new CHP systems are being derived from unit commitment and economic dispatch to solve both integer (binary) and linear optimization problems.

To further clarify, a steam system can be divided into 3 main sub-systems: supply side, energy conversion & distribution and condensate system. The problem formulation for a typical steam system can be summarized as follows:

The Objective function is a function of capital cost of equipment as well as the expected operating cost of the system configuration.

$$\text{Objective function} = \sum_{i=1}^{n} NPV\left(Capex_i + Opex_i * \frac{Hrs}{yr} * LC\right) \quad (1)$$

Where,

NPV: Net Present Value for the project

LC: Life Cycle of the new facility, normally used 25 years

The total capital cost includes major equipment used in the optimization analysis as decision variables:

$$\text{Capital cost} = \sum_{i=1}^{n}\left(Capex_{Blr_i} + Capex_{STG_i} + Capex_{STTi} + Capex_{Motor_i}\right) \quad (2)$$

Capital cost would be a function of the number and sizes of major equipment. For this specific case the capital cost of the solar thermal field (STF) is a major factor that has little maneuvering. (i.e. decision variables for the optimization algorithm):

- Boilers
- Steam turbine generator
- Solar Thermal Field
- New steam turbine drivers
- motors driven equipment as alternative drives with steam turbines

The total operating cost is function of the equipment performance and the impact on the energy consumption of the facility. The operating cost includes the following key elements:

- Fuel consumption
- Power export and import tariffs
- Solar thermal Field OPEX
- Make-up water treatment and chemicals
- CO2 Emissions

In the optimization analysis, there are key constraints that have to be met by the optimizer to confirm the validity of the results. Some of these constraints are related to equipment limitations and others related to systems limitations. Below are some examples of the key constraints used in the optimization analysis:

- Equipment constraint: Steam generation from boiler should be less than maximum limit and greater than minimum generation limit; i.e 30%.
- System constraint, steam production from steam supply equipment shall be greater or equal to steam demand required.
- System constraint: Available steam reserve from boilers should be more or equal to required steam reserve.
- Steam constraint: Input to a steam header should be equal to steam out from steam header to maintain a balance system without excess steam.
- Mathematical model constraint. Non-negative flows in the steam distribution network

Below is a generic mathematical representation for the steam system, where the steam balance representation includes:

Steam Balance for a steam header (a) = $\sum_{i=1}^{n} Stm_{in} - Stm_{out}$ (3)

Where, i & n are representing the equipment connected to this steam header

The boiler feed water (BFW) Balance is calculated as per the formula below

$$= \sum_{i=1}^{n} Blr_{BFW} + \sum_{i=1}^{n} STT_{BFW} - \sum_{i=1}^{n} DSH_{BFW} \quad (4)$$

Make-up water compensates for all loses from steam system, thus make-up water is equal to all loses in the steam system. More details are found in the reference listed in this section.

5. Results and Analysis

The CHP optimization model was evaluated with a solar field producing the 20T/hr during 7 daylight hours. This quantity was prorated to 5.83T/hr during 24 hr/day. The overall steam production distribution as a result of the integration is tabulated in Table 1. The CHP optimization model shows the operational cost improvements related to the fuel savings in the boilers in Table 2.

Table 1. *New Steam Production*

Equipment	Daily Hours of Operation	Saturated Steam @ 150psi & 187C	Percentage
Boiler 1	24	20T/h	14.6%
Boiler 2	24	54T/hr	39.5%
Boiler 3	25	57T/hr	41.7%
Solar Thermal Field	7	5.83 T/hr	4.2%
Total		136.83 T/hr	100%

Table 2. *Operational Improvements derived from 5.83T/hr of Solar Steam*

Parameter	**Units**	**Base Case**	**New Case - STT**	**Improve-ment**
Net Oper. Cost	MM$/yr	43.58	43.04	0.541
YR EI KPI		84.3	83.0	1.3
Tot Fuel Cons.	MMBtu/hr	705	689	15.7
Make-up Water	Klb/hr	54.14	54.08	15.7
Imported Power	MW	-42.0	-42.0	0.0

The economic analysis of the solar integration was done for a 25yr lifetime with an initial fuel price of 4$/MMBTU escalating 2% annually to finish at 6.5 $MMBTU. It is important to emphasize that the fuel price depends on the region of operation and it can also be tagged to an opportunity cost associated with selling the saved fuel in a specific market [8]. The next important input was the overall capex which is normalized per effective collector mirror area (ECMA) at 749 $/m^2. It includes all the installation works and components for an integration with a thermal capacity of 39 MW and an ECMA of 92,000 m^2. The annual operational expenditures for cleaning and maintenance are estimated at 1.5% of the capex.

At a discount factor of 5.5%, a fuel consumption improvement of 15.7 MMBtu/hr (137,537 MMBU per year of energy savings), and almost 10,000 Tons of CO2 reduction, the integration is unfeasible. At this point the need exists to determine at what combination will the critical variables increase the feasibility to produce a positive NPV. Two sensitivity analysis, Table 3 and Table 4, were done utilizing a range of values for both capex, fuel price and the associated monetary value with the reduced emissions.

Table 3. *Sensitivity Table: NPV as a function of Capex and Fuel*

Carbon Price $85 /T		**Capex: $/m^2 ECMA**						
		200	**300**	**400**	**500**	**600**	**700**	**800**
Fuel Price $/MMBTU	**4**	1,824,254	(6,796,296)	(15,416,845)	(24,037,395)	(32,657,945)	(41,278,495)	(49,899,044)
	6	6,320,569	(2,299,980)	(10,920,530)	(19,541,080)	(28,161,630)	(36,782,179)	(45,402,729)
	8	10,816,885	2,196,335	(6,424,215)	(15,044,765)	(23,665,314)	(32,285,864)	(40,906,414)
	11	17,561,357	8,940,808	320,258	(8,300,292)	(16,920,842)	(25,541,391)	(34,161,941)
	12	19,809,515	11,188,965	2,568,416	(6,052,134)	(14,672,684)	(23,293,234)	(31,913,783)
	14	24,305,830	15,685,281	7,064,731	(1,555,819)	(10,176,369)	(18,796,919)	(27,417,468)

Table 4. *Sensitivity Table: NPV as a function of Capex and Carbon Price*

Fuel Price @ 4$MMBTU		**Capex : $ /m^2 ECMA**						
		200	**300**	**400**	**500**	**600**	**700**	**800**
Carbon Price $/T	**0**	(9,673,364)	(18,293,914)	(26,914,464)	(35,535,013)	(44,155,563)	(52,776,113)	(61,396,663)
	25	(6,291,712)	(14,912,261)	(23,532,811)	(32,153,361)	(40,773,911)	(49,394,460)	(58,015,010)
	50	(2,910,059)	(11,530,609)	(20,151,159)	(28,771,709)	(37,392,258)	(46,012,808)	(54,633,358)
	75	471,593	(8,148,957)	(16,769,506)	(25,390,056)	(34,010,606)	(42,631,156)	(51,251,705)
	100	3,853,246	(4,767,304)	(13,387,854)	(22,008,404)	(30,628,953)	(39,249,503)	(47,870,053)
	125	7,234,898	(1,385,652)	(10,006,201)	(18,626,751)	(27,247,301)	(35,867,851)	(44,488,401)
	150	10,616,550	1,996,001	(6,624,549)	(15,245,099)	(23,865,649)	(32,486,198)	(41,106,748)
	175	13,998,203	5,377,653	(3,242,897)	(11,863,446)	(20,483,996)	(29,104,546)	(37,725,096)
	200	17,379,855	8,759,306	138,756	(8,481,794)	(17,102,344)	(25,722,893)	(34,343,443)
	225	20,761,508	12,140,958	3,520,408	(5,100,142)	(13,720,691)	(22,341,241)	(30,961,791)
	250	24,143,160	15,522,610	6,902,061	(1,718,489)	(10,339,039)	(18,959,589)	(27,580,138)
	275	27,524,813	18,904,263	10,283,713	1,663,163	(6,957,386)	(15,577,936)	(24,198,486)
	300	30,906,465	22,285,915	13,665,365	5,044,816	(3,575,734)	(12,196,284)	(20,816,834)
	325	34,288,117	25,667,568	17,047,018	8,426,468	(194,082)	(8,814,631)	(17,435,181)
	350	37,669,770	29,049,220	20,428,670	11,808,121	3,187,571	(5,432,979)	(14,053,529)
	375	41,051,422	32,430,873	23,810,323	15,189,773	6,569,223	(2,051,327)	(10,671,876)

The green color coding shows NPV values in the positive range. Red cells are the least feasible with NPVs less than -10$M and orange cells represent values from -10 - 0$M. The sensitivity analysis in Table 3 shows, that a for a feasible integration scenario to happen, the current capex needs to drop by almost 50%; and be combined with fuel prices reaching almost 11$/MMBTU, as well as a decarbonization monetized at 85$/T [9]. Moreover, Table 4 shows that on a 4-6 $/MMBTU fuel price scenario during the lifetime of the project, a 200 $/T carbon pricing would result in a positive NPV, provided technology costs decrease by almost 50%. These are two observations from the wide-ranging possibilities in the tables above. It is worth noting that, it is expected the fuel and carbon pricing for an operating facility will vary from year to year, causing cash flow variations that will move the financial results above or below expectations.

6. Conclusions

Having a CHP optimization tool to conduct a rigorous modeling of a refinery steam network was an essential step in analyzing the benefits of a solar thermal integration using PTC. Based on the conditions in our integration scenario, the relatively low fuel prices and high technology cost were the main barriers to building a solid economic case. Even though it is possible to further optimize the solar thermal configuration, it is clear that substantial capex reductions are needed to turn these solutions into viable decarbonization proposals.

Concerning the environmental goals and decarbonization targets, ithe organization’s final decision is to identify at what abatement cost (s) these projects can be pursued. As oil and gas facilities start to create decarbonization roadmaps, conducting wide-ranging sensitivity analysis can help understand how achievable these goals are and the financial impact they will render under different energy and environmental landscapes.

If the CST industry makes performance and cost improvements combined with a well-developed carbon market, these decarbonization solutions can become a reality for the oil and gas industry. In regions of high DNI such as the Middle East, facilities could be driven to hybridize their steam networks with CSTs, rapidly acquiring the experience to eliminate the unfounded reliability risk perception. This goal is attainable goal in this next decade as these facilites embark on an energy transition period to low-carbon fuels and adopt lower-emission technologies.

Data availability statement

Data regarding the economic analysis is internal to SA and is easily reproduced with standard financial formulas for NPV.

Underlying and related material

A Combined Heat & Power Optimization (CHP) Model developed and patented by Saudi Aramco consists of mathematical and thermodynamic representations to detect inefficiencies and opportunities to optimize complex steam utility systems.

Author contributions

All authors in this paper contributed in the conceptualization, formal analysis, investigation, methodology, and writing the original draft review and final editing.

Competing interests

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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