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Technology-to-Market Analysis of Integrated Combined Heat and Power Plants with Thermal Energy Storage in Commercial Facilities

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Technology-to-Market Analysis of Integrated Combined Heat and Power Plants with Thermal Energy Storage in Commercial Facilities

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by

Parker Wells

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ABSTRACT OF THE THESIS

Technology-to-Market Analysis of Integrated Combined Heat and Power Plants with Thermal Energy Storage in Commercial Facilities

by

Parker Wells

Master of Science in Mechanical Engineering

University of California, Los Angeles, 2017

Professor Richard E. Wirz, Chair

Thermal energy storage (TES) provides increased flexibility to residential and commercial customers in the operation of their combined heating and power (CHP) systems by separating generation of electricity from heating or cooling load. TES systems that can store high temperature exhaust heat (up to 600°C) from natural-gas powered CHP, such as low-cost elemental sulfur-based technology developed by UCLA researchers, can dramatically improve system economics. TES with quick heat response allows more commercial buildings with varying thermal and electrical demand to benefit from CHP.

In this thesis, realistic hourly electrical and heat usage data, along with energy pricing and installed system costs, were used to give insights into key economic indicators about the viability of CHP-TES systems for various commercial building types in Los Angeles, CA. The metrics used to understand the value of adding TES to existing CHP systems and new CHP-TES systems included upfront costs, payback period, and lifetime value for different capacity sizing of TES.

The results showed that adding TES to baseload CHP systems improves the lifetime value of the plant with a payback period of less than five years for many commercial building types. The large hotel building type offers the shortest CHP payback period of 2.8 years and TES retrofit payback period of 1.6 years. The value of the TES system to the end user can be more than 10 times the initial cost of the TES over a 15 year lifetime. Further, a sensitivity analysis of the TES cost, utility costs, and weather regions was performed. Accounting for regional variations in electricity prices, natural gas prices, and weather, we found that although electricity usage stays relatively constant, heat usage and TES economics vary greatly by region. Overall, we showed that high temperature thermal energy storage such as based on molten sulfur or molten salt, can efficiently store highly-valuable heat for enhanced small-CHP flexibility, thereby changing the economics of small-scale CHP systems for residential and commercial buildings, and promotes a more level grid from the demand side.

Keywords: Combined Heat and Power (CHP), Thermal Energy Storage (TES), Cogeneration, Commercial Building, Lifetime value, Payback Period, Building Heating, Energy Efficiency.

The thesis of Parker Wells is approved.

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Adrienne G. Lavine

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2017

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NOMENCLATURE

C	cost [$/kWh]
E	electrical demand [kWe]
F	fuel demand [kWt]
LV	Lifetime value [$]
PP	payback period [years]
Q	thermal energy [kWht]
r	capacity ratio

Subscripts and Superscripts

avg	average
el,sav	electricity exported to grid
el,rev	electricity cost savings
h	heating
NG	natural gas
PM	prime mover
TES	thermal energy storage

Greek Symbols

η	efficiency [%]

Acronyms

CHP	combined heat and power
CSP	concentrating solar power
TES	thermal energy storage

HHV	higher heating value

1. INTRODUCTION

Combined heat and power (CHP) is a well-established technology that generates over 12% of US electricity consumption, which is more than solar, wind, and geothermal generation combined [2, 7]. In California, approximately 85% of CHP capacity is generated by systems greater than 20 MW, but only 19.5% of the generation capacity is used for commercial application [3]. It is widely acknowledged that CHP can lead to significant emissions reductions and economic advantages in commercial facilities [4-6]. According to the 2016 DOE report, “Commercial buildings represent the strongest potential growth markets for CHP” [7].

In industrial CHP plants, concentrated solar power (CSP) plants, university campuses, and other facilities with large heating and/or cooling demands, thermal energy storage (TES) has been implemented to improve economics and reduce carbon emissions. Existing TES systems for industrial CHP and university campuses rely on hot or chilled water as the storage medium [7]. However, high temperature thermal energy storage media based on molten salt [8] or elemental sulfur [9] can provide significant advantages over water systems. By storing heat at temperatures near the exhaust temperature of the CHP prime mover (300 °C-500 °C) [10,11], heat energy stored in the TES system remains flexible in application. For instance, storing heat at such high temperatures allows for both low-temperature (~90°C) [12] and high-temperature (~220 °C) [12] absorption chillers operation, and enables efficient and economic operation of district heating (hot water and heating buildings) systems. It also provides high energy density, which allows for a more compact system and can have practical importance in space constrained commercial buildings.

Numerous thermal energy storage technologies and applications have been studied and implemented. Thermal energy commonly has economic and greenhouse gas emissions reduction benefits for the end users. Commercially available thermal energy storage systems use hot water and chilled water as the storage media (SM) in institutional and district heating applications, such as college campuses. The University of California, San Diego has implemented a 3.8 million gallon tank of water, which can save the university costs by shifting electricity usage from on-peak to off-peak times, as well as reducing energy usage by allowing chilling equipment to operate at or near design points [13]. Ice energy storage has reached commercial success and hot water thermal energy storage has also gained popularity in recent years [7].

Recent advancements in concentrated solar power led to significant study in new high-temperature TES systems including latent heat phase-change materials, and sensible heat materials: rock/solid, thermal oil, molten salt, and molten sulfur [9, 14-24]. Rock and concrete storage systems are very low cost but suffer from slow discharge rate due to poor thermal conductivity [20]. Thermal oils have a relatively high cost and have upper temperature limits that constrain their potential applications compared with alternatives such as molten salt (e.g. Therminol 66 limited to 345°C). Molten salt is the most common thermal energy storage medium for power tower concentrated solar power systems, as it can store heat at 545°C with a lower bound temperature of 290°C [8]. New molten salt chemistries have been studied which can reach higher temperatures, with tradeoffs in cost and efficiency [24]. Researchers at University of California, Los Angeles (UCLA), have researched a molten sulfur TES system, which has the potential to greatly reduce the cost of high-temperature thermal energy storage below the DOE SunShot goal of $15/kWh, and offer charge and discharge rates on par with competing liquid based sensible heat TES systems [9,23].

These recent developments have reduced cost, matured technologies, and familiarized industry with non-water based TES systems. The potential benefits from extending high-temperature TES beyond the CSP industry are significant. Water based TES systems are naturally limited to operate below the atmospheric boiling point (100°C) due to the high vapor pressure of water. Molten salt, molten sulfur, and thermal oil can store heat at higher temperatures, which allows for storage of waste heat in a compact and exergetically efficient TES system. Low cost, high temperature TES systems with fast discharge performance opens up the opportunity for stored heat to provide process steam on demand, and also discharge heat to absorption chillers to provide cooling to end user facilities.

One common source of heat for commercial and industrial facilities is cogeneration, or combined heat and power (CHP) plants. The most common fuel source for CHP is natural gas [7]. In “topping cycle” CHP plants, which are the most common, the fuel is used to generate electricity or drive a process at a facility. The exhaust heat from the topping cycle is then utilized to provide value to the facility. CHP is especially common in industrial facilities, where process steam is commonly used in paper mills operations, chemical production, food processing, and refining. These industrial processes require various pressures of superheated steam as process heat and generally operate 24 hours per day, 7 days per week. As a result, the common operation of a CHP plant, which operates at a constant or “baseload” level, is similar to the facility’s electrical and heat demand.

The increase in variable renewable energy sources, the spread of renewable portfolio standards to the majority of US states, and developments in natural gas extraction have led to rapid changes in the economics of energy. Simultaneously, new technologies that include microturbines, fuel cells, and absorption chillers are being developed, which make small-scale CHP systems economically viable. Due to the significant improvements in energy related costs, increased power reliability, increased energy efficiency, and reduced global warming emissions that CHP systems offer, the federal and California state governments have shown significant interest in increasing CHP portfolios [7, 3, 11]. Smaller CHP systems, especially those for commercial buildings and institutions, are shown to have a large technical potential in a report prepared for the US Department of Energy’s Advanced Manufacturing Office [7].

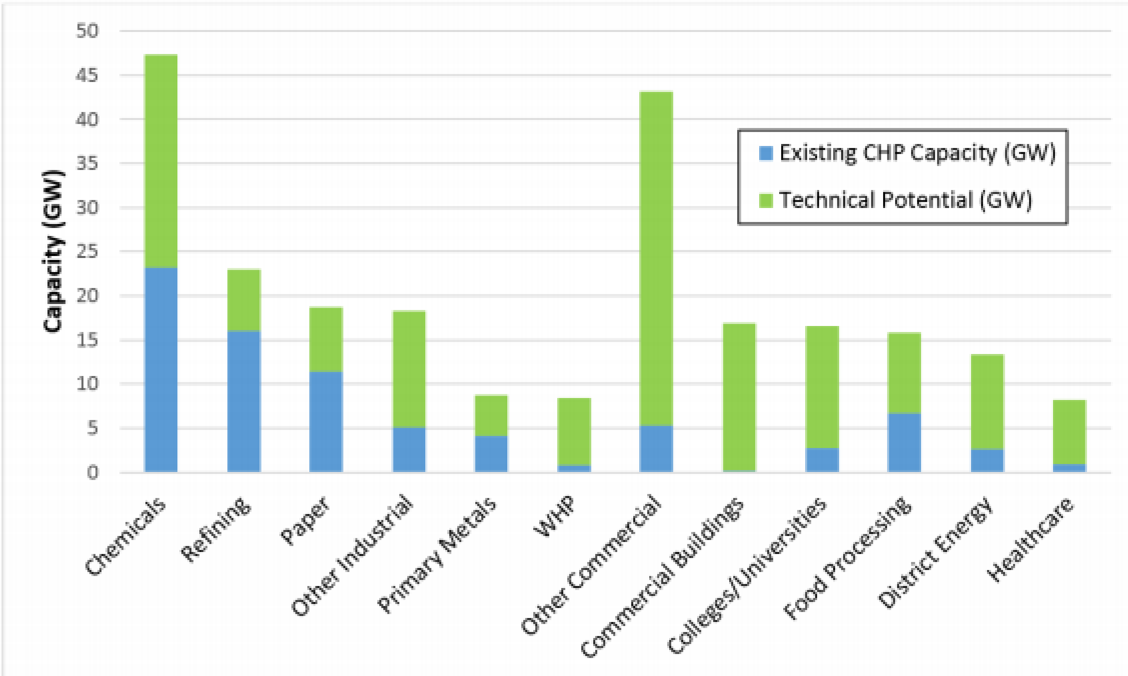


Figure 1: Existing and Technical CHP Potential in the United States (Credit: Hampson et al. [7])

The relatively low penetration of CHP in commercial facilities, compared with industrial facilities, can be attributed to a number of factors. One critical factor is the scale of commercial systems. Industrial paper mills, for example, commonly have prime movers such as gas turbines or engines with combined capacities of 5-50 MW. Industrial facilities size the entire system to the required heat and can sell their over-generated electricity to the electrical grid at a predetermined rate. Unlike industrial facilities, commercial facilities and institutions, such as hotels, hospitals, and schools commonly size their CHP units to the electricity demand. In addition, commercial facilities require less electricity and heat, and commonly construct CHP plants with capacities ranging from 50 kW to 5 MW. A second critical difference between commercial and industrial CHP, which greatly affects system economics, is the operations of an end user. Many industrial facilities require process heat during day and night, which closely match a baseload CHP facility's heat generation. Commercial facilities often use the heat from CHP to provide space heating and hot water to the building, which varies intraday and seasonally.

Significant work has been conducted to understand the opportunity for commercial CHP and devising strategies for CHP, and CHP with TES [25]. Efforts have been made to analyze the economic viability of CHP systems for a generic region, such as fuel-cell powered CHP [26]. Similarly, energy-consumption focused case studies that investigate CHP with existing water-based TES systems have been completed for regions of the US [27]. Economic optimization with water-based TES for combined cooling, heating, and power (CCHP), has also been studied for residential and district heating application [28]. Nevertheless, the literature lacks studies that analyze the economic impact of thermal energy storage as a retrofit to CHP plants, as well as studies that can recommend strategies for sizing CHP-TES units based on industry standard metrics, such as payback period, lifetime value, and total installed cost. Research studies that focus on the sensitivity of CHP-TES economics to electricity and natural gas prices and to regional weather differences are also lacking in the literature.

The objective of this work is to use realistic hourly electrical and heat usage data, along with realistic energy pricing and installed system costs, to give insights into key economic indicators about the viability of CHP-TES systems. The analysis in this thesis evaluates the value and appropriate capacity sizing of TES if added to existing CHP without storage for various commercial building types in Los Angeles, CA. New CHP-TES systems are also economically evaluated and sized. The metrics used to understand the value of adding TES and new CHP-TES systems are upfront costs, payback period, and lifetime value. By evaluating a wide range of commercial facilities, this thesis suggests the most suitable building types for CHP-TES. Moreover, TES costs vary widely by core technology [29]. To this end, the thesis also reports a sensitivity analysis examining the importance of the cost factor for TES additions and new CHP-TES installations. The Los Angeles, CA case study is compared with results from Seattle, WA and Atlanta, GA to illustrate the state-by-state differences in CHP economics, due to utility rate variations, incentives, building, and weather variations as highlighted by McLarty et al. [30].

2. COMMERCIAL FACILITY CHP-TES MODEL

Eight building types were selected from the US Department of Energy's Commercial reference buildings. These building types were among the larger and more energy intensive reference buildings. Table 1 below shows all 16 building types, which were selected for this study with information from the National Renewable Energy Laboratory's technical report for the DOE Building Technologies program [31].

Table 1: Reference building types [31]

Building Type	Selected for Study	Floor Area (sq. ft.)	No. of Floors
Large Office	X	498,588	12*
Hospital	X	241,351	5*
Secondary School	X	210,887	2
Large Hotel	X	122,120	6
Primary School		73,960	1
Medium Office		53,628	3
Warehouse	X	52,045	1
Supermarket	X	45,000	1
Small Hotel		43,200	4
Outpatient Healthcare	X	40,946	3
Midrise Apartment		33,740	4
Stand-Alone Retail		24,962	1
Strip Mall		22,500	1
Small Office		5,500	1
Full Service Restaurant	X	5,500	1
Quick Service Restaurant		2,500	1

* indicates additional basement floor

The building selection for this analysis was biased toward larger facilities. Larger facilities are likely to require more electricity and to have more advantageous CHP economics. For example, in the hospitality industry, CHP is currently only recommended for hotels with 100 rooms or more, and CHP is economically advantageous in over 90% of hotels with over 1000 rooms [32]. The reference building models were simulated using EnergyPlus software [33] in the Los Angeles region. The buildings were assumed to be constructed after 1980, but are not new constructions. EnergyPlus software provided hourly electricity and natural gas consumption data for the year for various building uses. In particular, the hourly electric demand for heating, cooling, interior lights, exterior lights, interior equipment, exterior equipment, fans, pumps, refrigeration, heat rejection, and humidification, as applicable to the building type were obtained from EnergyPlus. It also provided natural gas demand for heating, interior equipment, and water systems. The capacity of CHP prime movers for commercial applications was selected based on the electrical demand of the facility. It has been shown that 0.5 of the average electrical demand is an appropriate capacity for the prime mover, and is used as the baseline electrical generator capacity [27].

To calculate the natural gas fuel demand that can be replaced by the prime mover exhaust heat, the natural gas used for building heating and water was summed, but natural gas for interior equipment was not, as exhaust heat is unlikely to replace natural gas for interior appliances, such as stoves. Natural gas fuel, F_{NG}, used by the prime mover with a capacity of 0.5 times the average electrical demand, E_{avg}, was calculated using Equation (1):

$$F_{NG} = {}^{0.5 \times E_{avg}}\!/_{\eta_e} \qquad [1]$$

where η_e denotes the prime mover higher heating value (HHV) efficiency, and is taken to be 0.26 in this study [10]. The thermal efficiency of the CHP unit (η_{CHP}) is assumed to be 0.57 [10]. The exhaust heat from the CHP prime mover, after accounting for the thermal efficiency of the heat exchanger and TES (η_{TES}), provides the heat available to the building (Q_{CHP}) as shown in Equation

(2a). When natural gas is directly utilized for heating the building, heating efficiency (η_h) is used to calculate the natural gas fuel required as shown in Equation (2b). η_{TES} and η_h are assumed to be 0.95 and 0.8, respectively.

$$Q_{CHP} = F_{NG} \times \eta_{TES} \times \eta_{CHP} \qquad [2a]$$

$$Q_{CHP} = F_{NG} \times \eta_h \qquad [2b]$$

The base case of CHP without TES is obtained using the electricity and natural gas demand from EnergyPlus models and assuming baseload operation of the CHP unit. Figure 2 and Figure 3 show the electricity and heat demand, respectively, along with the electricity and heat generation from an appropriately sized TES unit, for 4 days in winter, spring and summer. In this example, a large hotel in Los Angeles, CA is used.

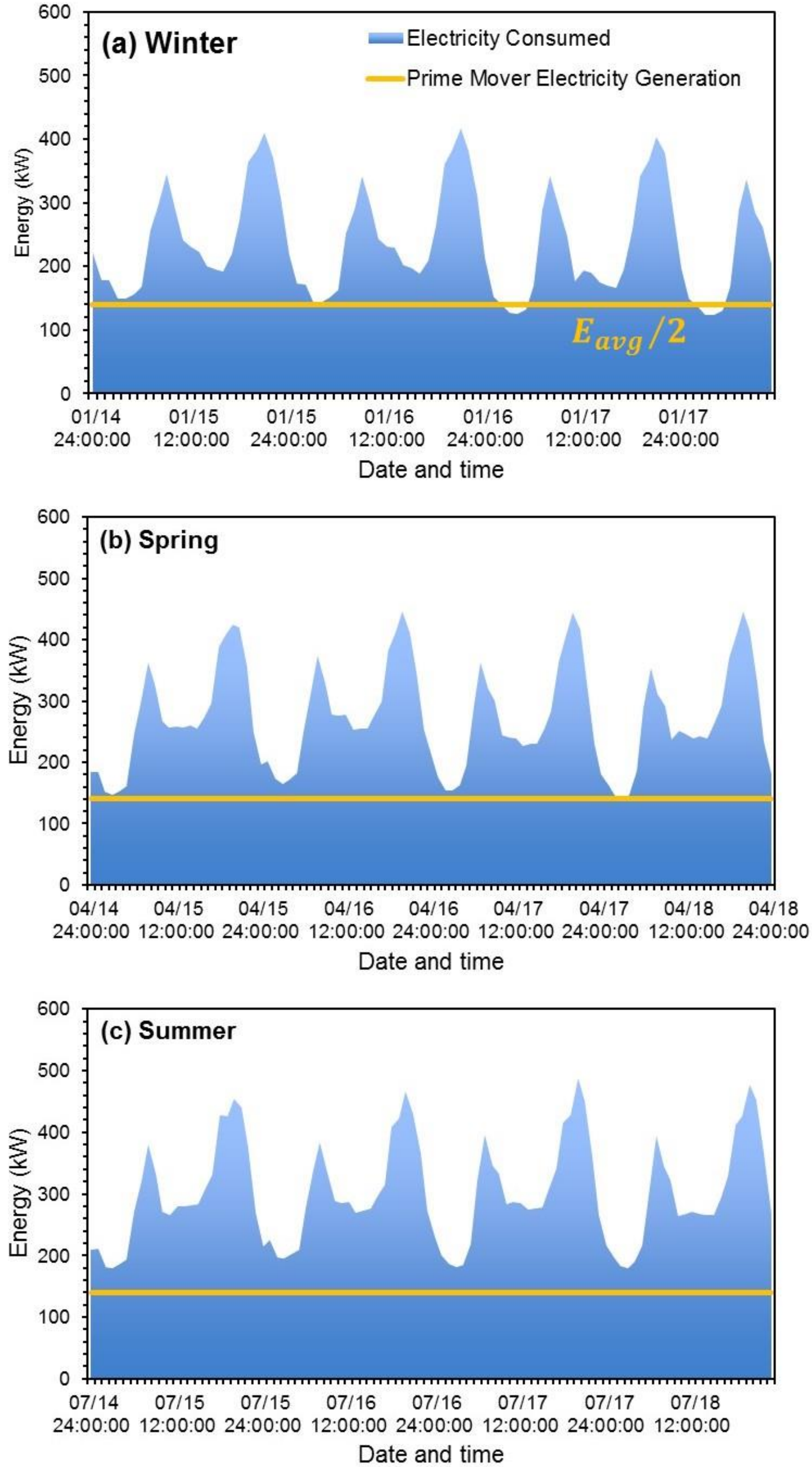


Figure 2: Electricity demand and production 4 days in (a) winter, (b) spring, and (c) summer

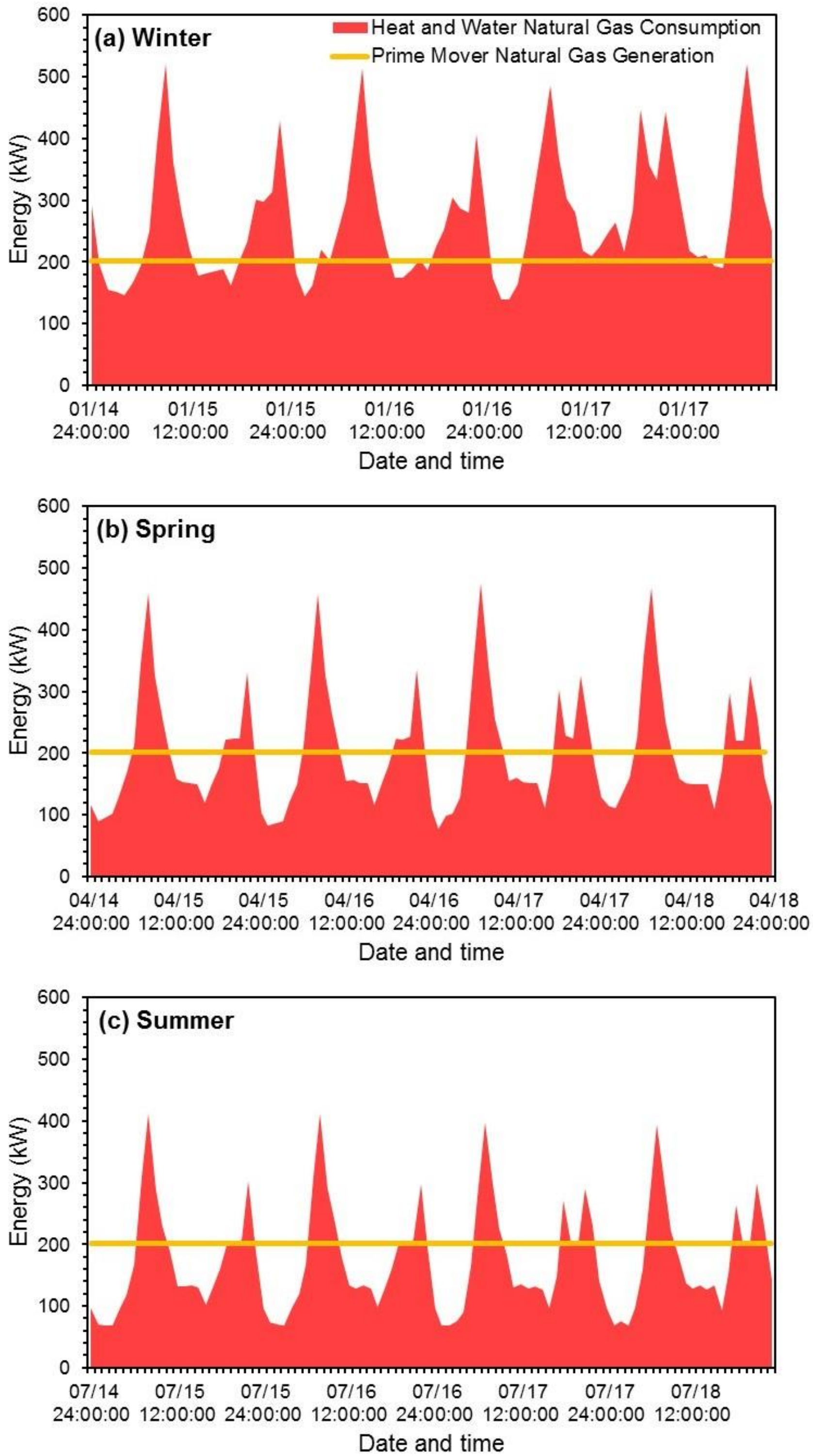


Figure 3: Heat demand and production 4 days in (a) winter, (b) spring, and (c) summer

As represented in Figure 2a-c, electricity generation rarely exceeds the consumption of the building. When this occurs, electricity is assumed to be purchased by the grid or wasted, depending on the utility region, as discussed in Section 3. In Figure 3a-c, the heat requirement is often more than a baseload CHP unit without TES can provide. In this base case without TES, it is assumed that additional natural gas must be purchased to fill the need. When the heat generated exceeds the consumption of the building, the heat is expelled as waste heat.

In the CHP-TES case however, excess heat is stored and discharged in place of additional natural gas purchases. Figure 4 shows the operation schematic for CHP-TES systems for different building heat requirement scenarios. When the CHP unit produces more heat than the building requirement and the TES is not fully charged, the TES stores excess heat as shown in Figure 4a. If the TES unit is fully charged (hot), heat is exhausted. When the CHP unit provides less heat than the building requirement, heat is discharged from the TES as shown in Figure 4b. Once the TES is completely discharged (cool), additional natural gas is purchased and sent through a boiler to provide the additional required heat, as shown in Figure 4c. Boiler and TES ramp rates are assumed ideal in this analysis. Figure 5 shows the general logic tree, which is computed for each hourly time step. It is assumed that the TES is completely discharged, or cool, at the beginning of the year.

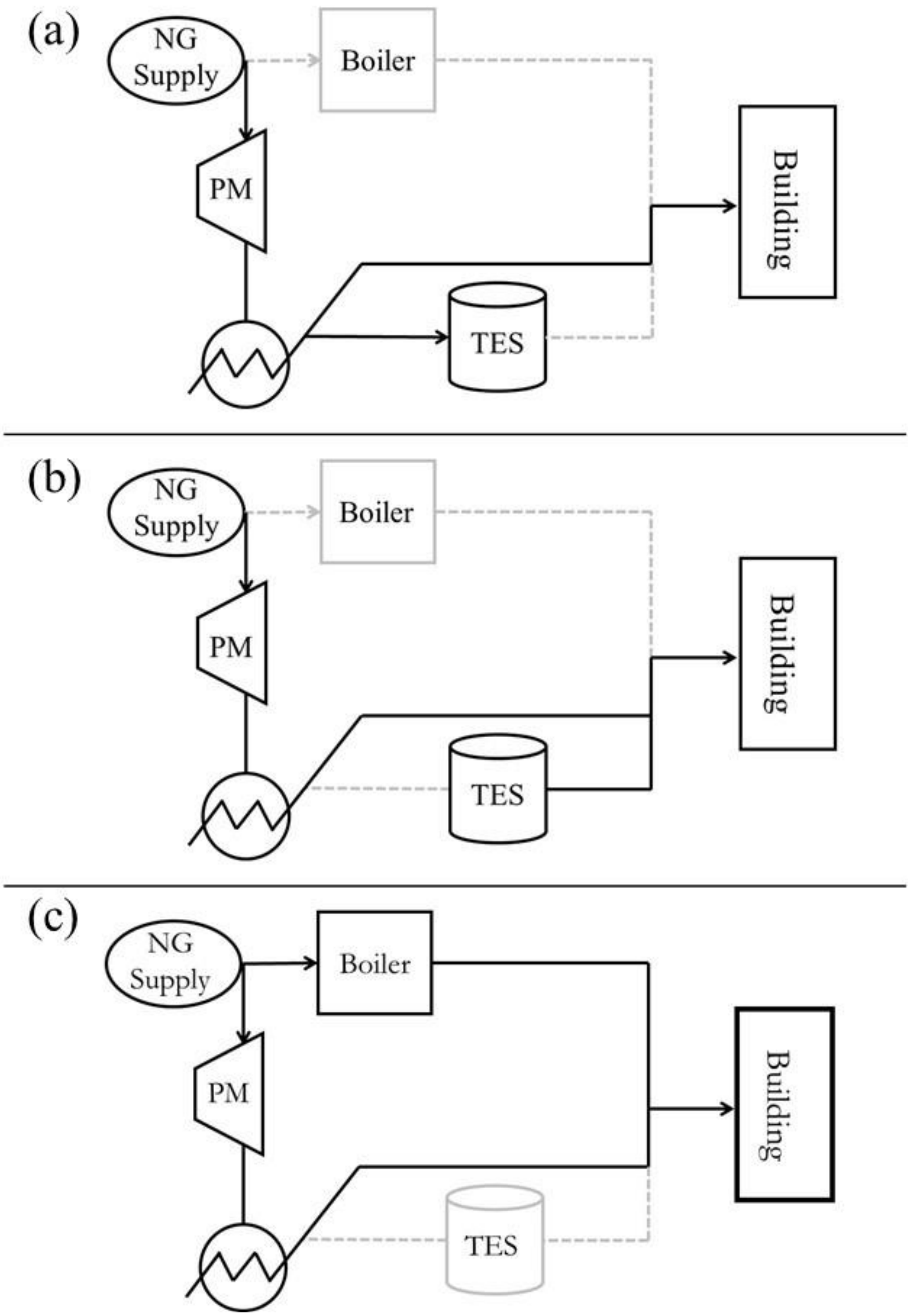


Figure 4: Operating schematics: (a) Building heat requirement < CHP supply and TES is charged; (b) Building heat requirement > CHP supply and TES is discharged; (c) Building heat requirement > Supply from CHP and TES, and additional natural gas is burned

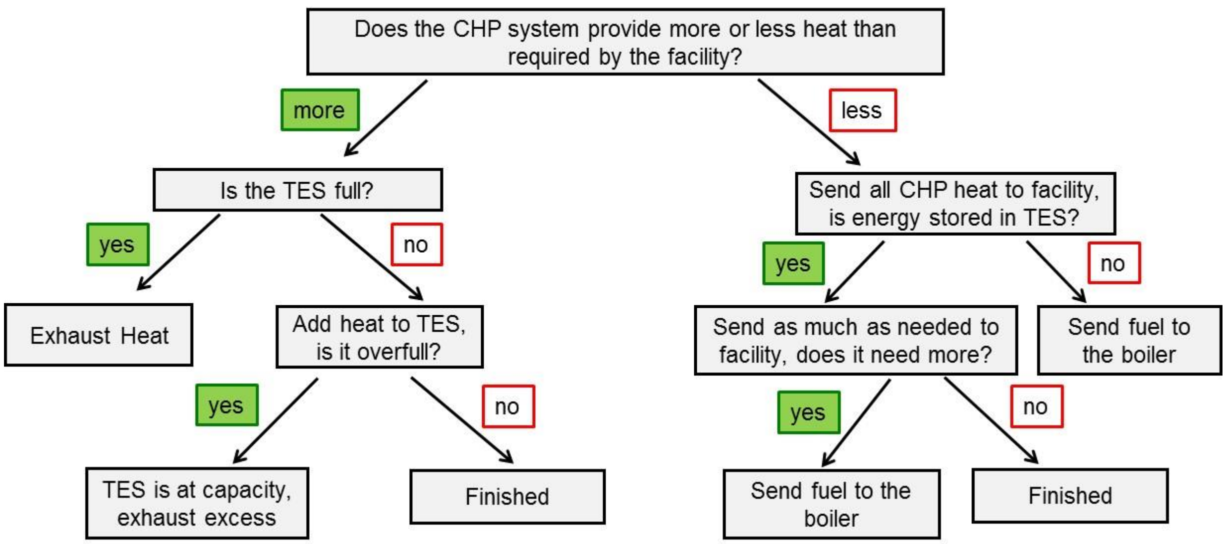


Figure 5: Hourly logic tree for CHP-TES systems

The ideal TES tank size is found using this analysis and the economic model discussed in the following section.

3. TECHNOLOGY-TO-MARKET MODEL

The economic value of CHP-TES units can be quantified using two main metrics. First is the "payback period", which is the amount of time the initial investment will pay for itself in cost savings. The second is the "lifetime value", or the total amount saved over the lifetime of the system minus the initial costs and ongoing expenses. A third consideration that can determine the feasibility of a CHP project is the upfront cost of the system. Facilities often have multiple potential energy and cost savings projects to consider and limited annual expense budgets. These real-world constraints vary greatly by project site and are often prioritized over payback period and lifetime value considerations. Installed system cost is also determined, but not used as a limiting factor in this analysis.

3.1. Initial Costs

According to the EPA's CHP Partnership's 2015 "Catalog of CHP Technologies", installed cost for CHP prime mover technologies were as follows [11]:

- Reciprocating Engines: $1,500-$2,900
- Microturbines: $2,500-$4,300
- Fuel Cell: $5,000-$6,500
- Gas Turbines (5-40 MW): $1,200-$3,300

Microturbines and fuel cells are still gaining widespread use, and are anticipated to continue to decrease in price. Other estimates from the University of Florida suggest microturbine capital costs to range from $700-$1,100 plus $75-350/kW in heat recovery and an additional 30-50% for installation [34]. The high end of these ranges would put the installed cost of a microturbine CHP plant at $2,175/kW. The prime mover cost with heat recovery is taken to be $2,200/kW. Incentives, including self-generation incentive program (SGIP) in California, which offers up to $420/kW of installed capacity for microturbines and engines and 1,490/kW for fuel cells, were not considered in this analysis.

The TES cost of $15/kWh is due to the DOE SunShot goals [29]. Existing molten salt technologies cost $30-$40/kWh [8], but recent research in molten sulfur TES suggests future TES systems below the SunShot benchmark [23]. In this analysis, heating and boiler equipment is not considered, as this component is required in the base case, with CHP, and CHP-TES. It is likely that a smaller boiler would be required if CHP is installed, but this has been shown to play a minor role in the overall system [27].

3.2. Continued Costs, Avoided Costs, and Revenues

The 2016 Average CA Investor Owned Utility (IOU) rates for commercial facilities, as suggested by the California Energy Commission (CEC), were used as the baseline electricity and natural gas rates [35]. The suggested rates are $10.20/MMBtu for natural gas and $0.1638/kWh for electricity. The electricity purchase rates are the net of any standby, departing load, and demand charges. The analysis was also run with an approximation of Los Angeles Department of Water and Power (LADWP) electricity rates and Southern California Gas Company (SCG) natural gas rates. These two utilities serve much of the City of Los Angeles. LADWP electricity purchase rates are similar to the CA IOU rates and hence, were not changed in this analysis. According to the LADWP 2016-2020 rates fact sheet, the average cost for medium and large commercial facilities are $0.1894/kWh and $0.1746/kWh, respectively [36].

A large difference is found in the value of selling electricity back to the grid. The baseline CEC suggested rate is $0.11/kWh. The LADWP selling rates used for this analysis, from the February 2017 Standard Energy Credit, are $0.0353 for high-peak demand, and $0.0196 for low-peak and base demands. For comparison, in June 2017, these rates were $0.0321 for high and low-peak demands, and $0.0178/kWh for base demand. The SCG natural gas purchase rate is $0.65334 per therm, based on the SCG Schedule No. G-10 for Core Commercial and Industrial Service [37].

3.3. CHP-TES Value and Core Metrics

Two separate payback periods were calculated for this study. In the case of a retrofit, in which TES is added to an existing CHP system, the avoided cost of purchasing supplemental natural gas (C_{NG}), is compared with the one-time installed cost of the TES (CTES). The payback period of a TES retrofit, PP_{TES}, is calculated using Equation (3).

$$PP_{TES} = {C_{TES}}/{C_{NG}} \qquad [3]$$

In the case of payback period for a new CHP-TES unit (PP_{CHP}) the annual avoided electricity cost savings ($C_{el,sav}$), the annual additional natural gas cost (C_{NG}), and the annual revenue generated by electricity exported to the grid ($C_{el,rev}$), is compared with the installed cost of both the prime mover (C_{PM}) and TES (C_{TES}). This calculation is shown in Equation (4).

$$PP_{CHP} = \frac{C_{PM}+C_{TES}}{C_{el,sav}+C_{NG}-C_{el,rev}} \qquad [4]$$

Additionally, two separate lifetime values were calculated for this analysis, lifetime value for TES retrofit (LV_{TES}) and lifetime value for CHP-TES installation (LV_{CHP}). A 25-year and 30-year system lifetimes are common for industrial CHP systems [38-40]. However, for smaller scale commercial CHP systems, a more conservative 15-year system lifetime was used based on end-user interviews, and the conservative industry approach to long-term energy projects [41, 42]. Equations 5 and 6 are used to calculate the total value of the system to the end user.

$$LV_{TES} = 15\ years \times C_{NG} - C_{TES} \qquad [5]$$

$$LV_{CHP} = 15\ years \times \left(C_{el,sav} + C_{NG} - C_{el,rev}\right) - (C_{PM} + C_{TES}) \qquad [6]$$

These calculations were completed for each of the eight reference building types with Los Angeles, CA weather data files with varying TES capacities from no TES to up to 3 times the average heat requirement. The results in the following section (Section 4) demonstrate the potential value in TES in commercial CHP systems in Los Angeles, CA, as well as other regions in the United States and other utility service areas.

4. RESULTS AND DISCUSSIONS

4.1. TES retrofits of existing CHP systems in Example Market (Los Angeles, CA)

Adding TES to existing CHP plants had a positive impact on many of the commercial building types. Table 2 includes the average electrical and heat demand for each building type in Los Angeles.

Table 2: Average electricity and heat demand for various building types in Los Angeles, CA

Building Types	Electricity Average Usage [kW]	Natural Gas Average Usage (kW)	Electricity/ Natural Gas
Large Office	758.3	55.0	13.8
Hospital	970.1	366.2	2.6
Secondary School	295.0	51.9	5.7
Large Hotel	280.7	205.7	1.4
Warehouse	20.8	10.8	1.9
Super Market	221.0	35.5	6.2
Outpatient Healthcare	178.7	115.6	1.5
Restaurant	40.2	10.4	3.9

Figure 6 shows the payback period for TES in all eight of the studied buildings using the CEC suggested utility rates. The TES payback periods are plotted against the capacity of the TES system normalized with the average hourly electricity usage of the system, referred to as the capacity ratio (*r*) in Figure 6. Though it varies greatly by industry and end user, projects with 3-10 year payback periods are often deemed worth consideration for capital investment. From the payback period analysis, warehouses, secondary schools, and large hotels are the strongest potential sites in Los Angeles, CA. Outpatient facilities and supermarkets also may qualify for consideration. It should be noted that this analysis does not take incentive programs into account, and therefore the real economics could be significantly more advantageous than are shown here.

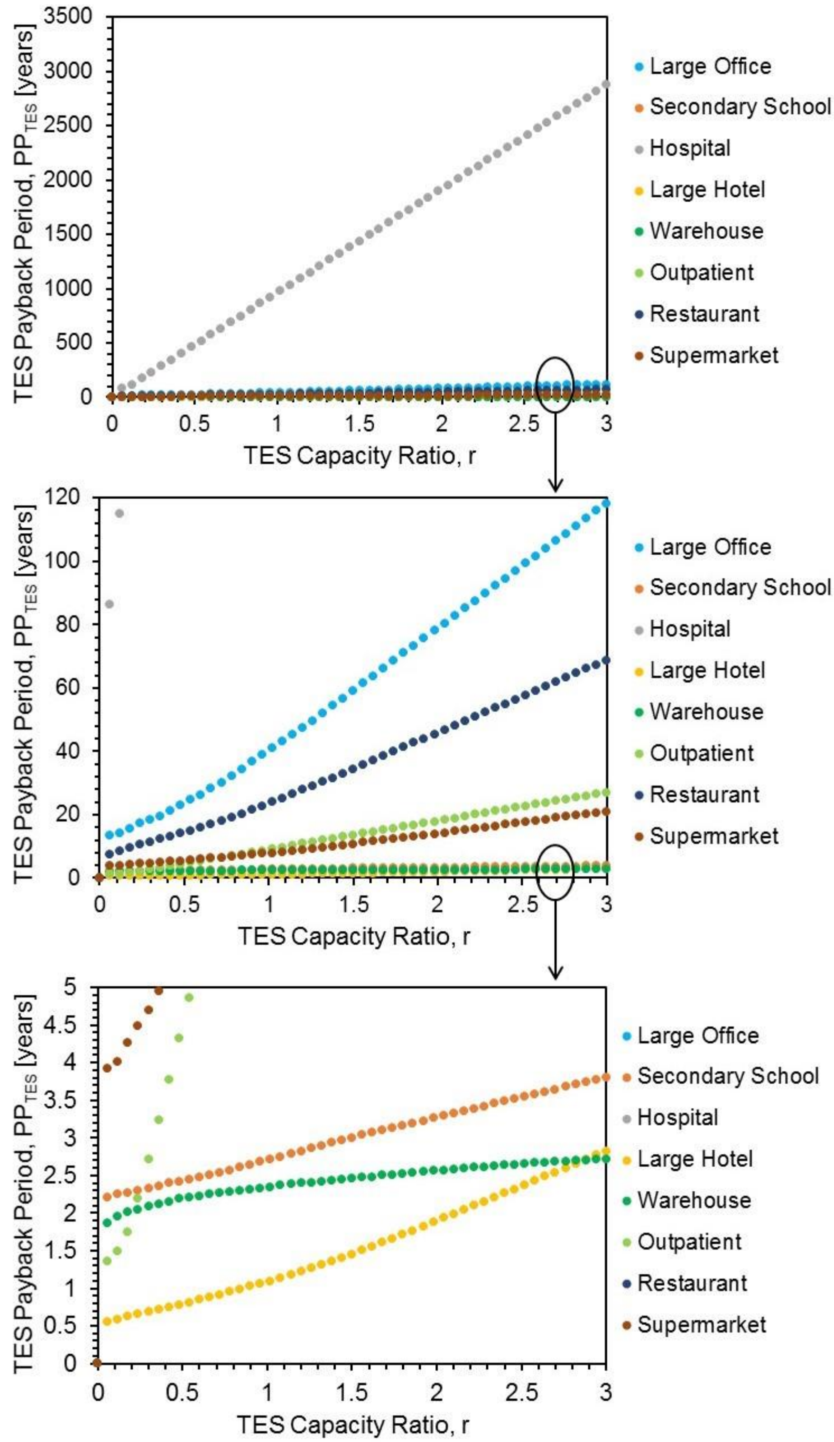


Figure 6: Variation of TES payback period with TES capacity ratio for various building types

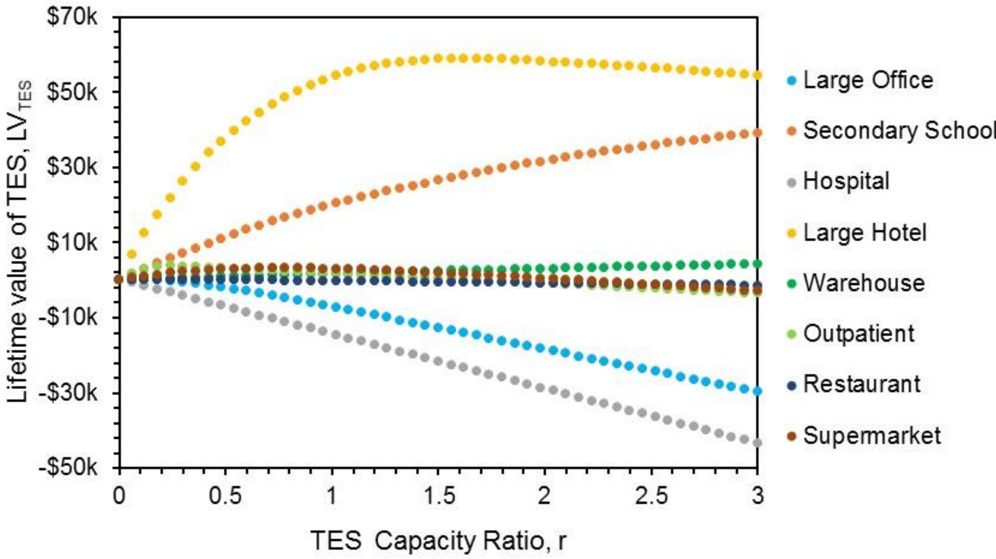


Figure 7: Effect of TES capacity ratio on lifetime values of TES retrofit for different building types

The lifetime value of the TES retrofit for each of the reference building types is shown in Figure 7. The five building types identified as potential retrofit candidates by payback period are secondary school, large hotel, warehouse, outpatient and supermarket. Due to the advantageous payback periods and lifetime values of warehouses, secondary schools, and large hotels, these three building types were selected for further analysis. Table 2 shows that these three building types also had the lowest ratio of electricity usage to natural gas usage (below 2.0).

In each of these three building types, the TES system that offers the maximal lifetime value has a simple payback period of less than 10 years. Table 3 shows the installed cost, lifetime value, payback period at the largest lifetime value, and the installed costs and lifetime value of system with a payback period of three years.

Table 3: Preferred TES capacity for different building types

Building Types →	Warehouse	Secondary School	Large Hotel
A) Maximum Lifetime Value			
TES Capacity [kWh]	186	1570	460
Installed Cost [$]	2.8k	23.6k	6.9k
Payback Period [years]	6.3	5.0	1.5
Lifetime Value [$]	7.6k	47k	61.8k
B) Three-year Payback Period			
TES Capacity [kWh]	104	448	932
Installed Cost [$]	1.6k	6.7k	14.0k
Payback Period [years]	3	3	3
Lifetime Value [$]	6.2k	27.0k	56.1k

Figure 8 shows the Payback period and lifetime value of TES retrofits of various capacities for three different building types. In the case of the large hotel, the maximum lifetime value occurs in shorter than 3 years, so the three-year payback period is an irrelevant consideration. However, in the case of the warehouse, cutting the payback period from 6.3 to 3 years resulted in a difference in lifetime value of 18% and might be considered by an end user. These results indicate that an important initial factor to evaluate when considering a TES retrofit is the electricity to heat usage ratio. This was shown to be smallest in warehouses, secondary schools, and large hotels. Despite the overall energy usage of these buildings to vary greatly, a large hotel requires almost 20 times the amount of heat of a warehouse. These two building types share much more similar economics than a warehouse and a full-service restaurant, which have very similar heat requirements but different electricity requirements.

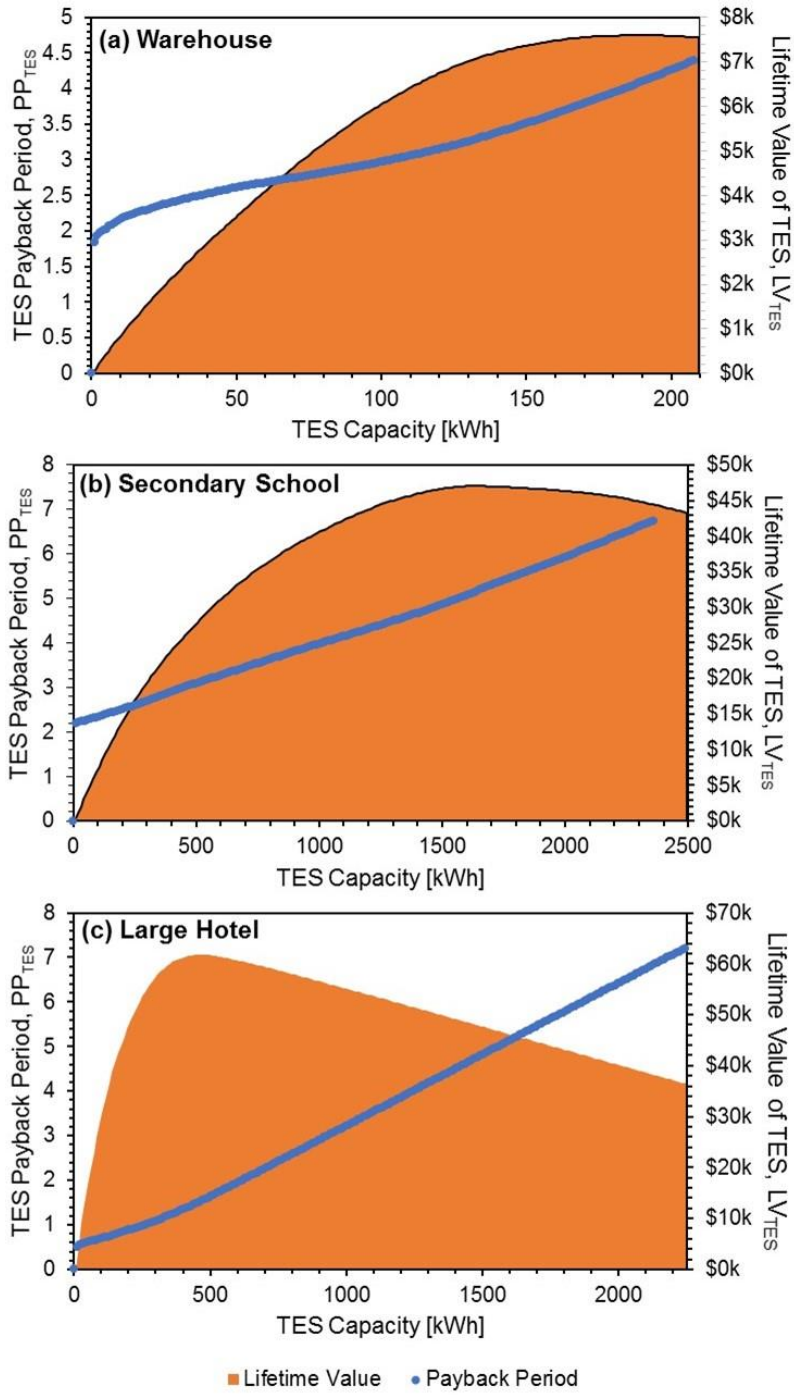


Figure 8: Payback period and lifetime value of TES retrofits of various capacities for (a) Warehouse, (b) Secondary schoool, and (c) Large hotel building types.

4.2. CHP-TES installations in Los Angeles, CA

As shown in Figure 1, the commercial segment makes up a minority of the US CHP capacity, but the majority of the technical potential. An analysis was completed to understand the value of TES for a new CHP-TES system using the methodology described in Section 3.3 “CHP-TES Value and Core Metrics”. In this analysis, the TES unit capacity was varied, but the economics were compared with a base case that no CHP exists. This analysis found that TES plays a comparatively small role on overall CHP-TES economics. The following section, 4.3, will consider the impact of varying the prime mover capacity.

Figure 9 and Figure 10 show the payback period and lifetime value of a CHP-TES installation with respect to TES capacity, respectively. The payback period and lifetime value remain relatively constant, independent of the TES capacity. Large hotels, which were shown to benefit from TES retrofits in the previous section, are shown in more detail in Figure 12.

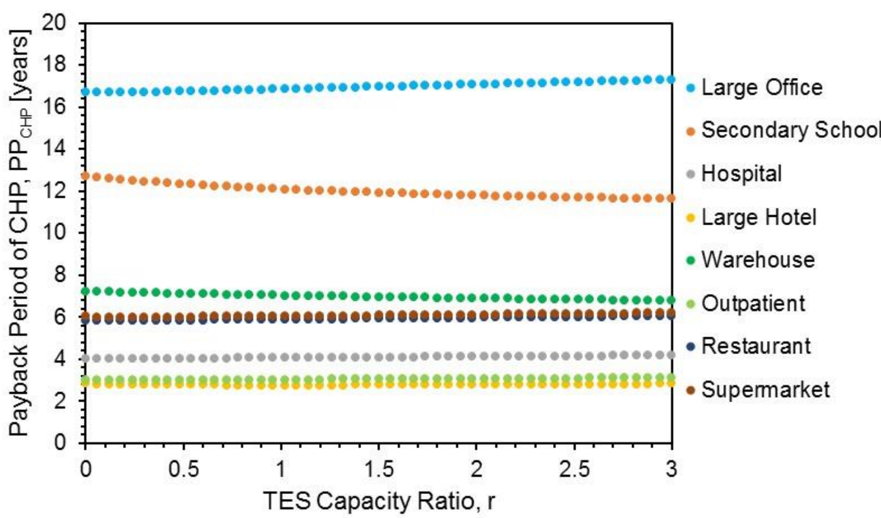


Figure 9: Effect of TES capacity ratio on payback period of CHP-TES installation

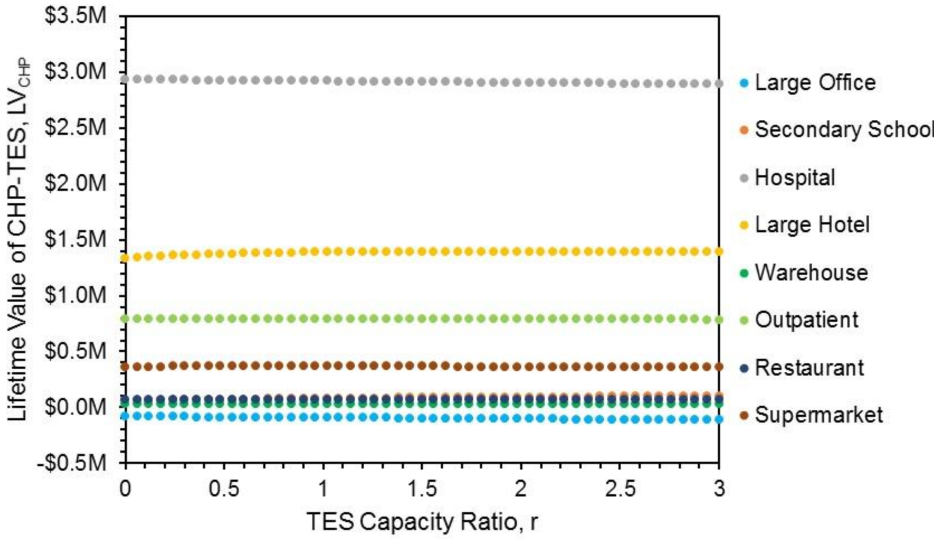


Figure 10: Influence of TES capacity ratio on lifetime value of CHP-TES installation

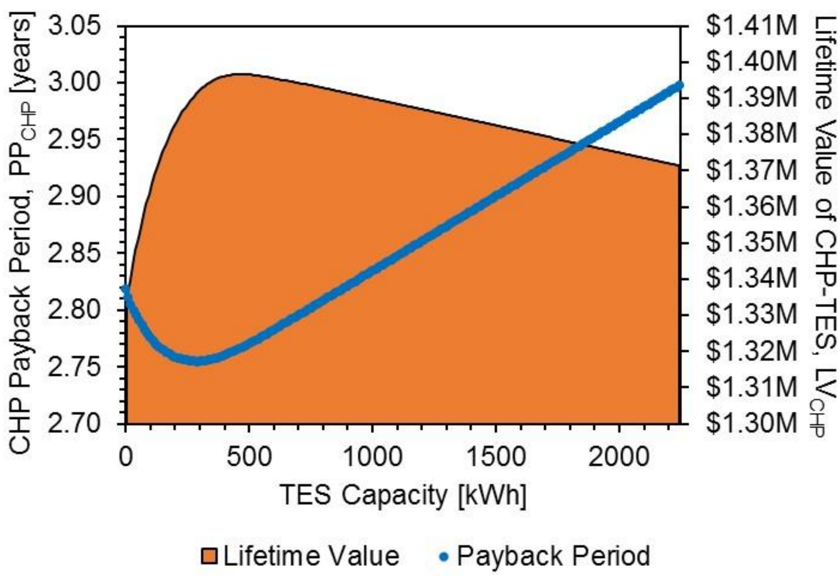


Figure 11: Large office payback period and lifetime value for new CHP-TES installation of various TES capacities

The variation in pricing is the same, but electricity and prime mover costs dominate CHP-TES economics. In this example, the addition of TES plays a less than 10% role in the overall system economics. Table 4 includes the costs for PM and a representative TES sized twice the average hourly heat requirement. This demonstrates that while TES can lead to less than 10% improvement on CHP-TES system economics, the TES equipment can represent 0.2%-2% of the installation cost.

Table 4: Prime mover and TES cost for various building types

Building Types	PM Cost [$]	TES Cost [$]	PM Cost/ TES Cost
Large Office	$834k	$1,651	505.3
Hospital	$1,067k	$10,985	97.1
Secondary School	$325k	$1,557	208.5
Large Hotel	$309k	$6,171	50.0
Warehouse	$23k	$325	70.3
Super Market	$243k	$1,066	228.1
Outpatient Healthcare	$197k	$3,467	56.7
Restaurant	$44k	$311	142.3

4.3. Prime mover sizing in Los Angeles, CA

The standard CHP system in sections 4 and 4.2 have used a prime mover capacity that is half of the average building electrical demand. In the EPA CHP Partnership report, PM sizing strategies for nearby Anaheim, CA ranged from 40%-70% of average electrical demand. For the nearby hot climate of Las Vegas, NV, PM sizing ranged from 33-64% of E_{avg} [32]. This analysis evaluated the impact of a range of PM capacities from 0.125 E_{avg} to 1 E_{avg}, in steps of 0.125 E_{avg}. Table 5 offers the PM capacity which maximizes lifetime value of the CHP-TES plant. It also shows the payback period of the CHP-TES system if installed together, the appropriate TES capacity to be paired with the appropriately sized PM, and the payback period of the TES unit if installed as a retrofit to the appropriately sized PM.

For all building types, the PM capacity that maximized LV_{CHP} was 3/8 E_{avg} to 5/8 E_{avg}. In all building types, except the hospital, TES would increase the value of the plant with PP_{TES} ranging from 2.0-8.3 years. The secondary school would benefit from the largest TES unit, despite a relatively small average thermal load (52 kW heat), and has a PP_{TES} under 5 years. The large hotel offers the shortest CHP payback period and TES retrofit payback period.

Table 5: Prime mover sizes and TES capacities offering maximal CHP lifetime value

Building Type	**PM Capacity for max LV_{CHP} [fraction of E_{avg}]**	**PM Capacity for max LV_{CHP} [kW]**	**PP_{CHP} [years]**	**TES Capacity [kWh]**	**PP_{TES} [years]**
Large Office	0.375	284.4	7.1	151.6	8.3
Hospital	0.625	606.3	4.5	0.0	0.0
Secondary School	0.375	110.6	5.8	1711.1	4.7
Large Hotel	0.5	140.3	2.8	449.1	2.0
Warehouse	0.375	7.8	5.6	170.4	4.6
Super Market	0.5	110.5	6.0	132.6	7.6
Outpatient Healthcare	0.5	89.3	3.0	35.7	3.9
Full Service Restaurant	0.375	15.1	4.3	32.2	7.3

Figure 12 and Figure 13 show the impact of PM sizing for the secondary school and large hotel cases, respectively. The figures show how the value of TES and appropriate capacity of a TES system change with PM size.

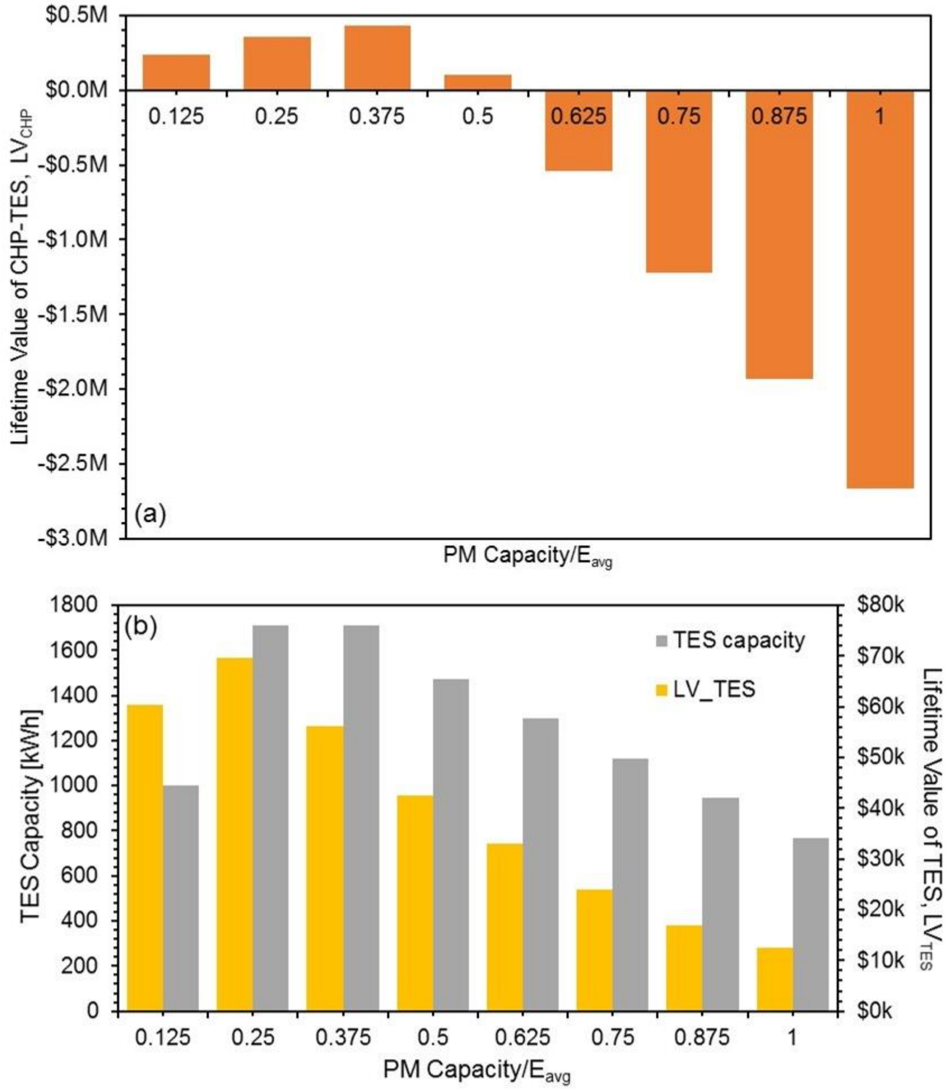


Figure 12: Impact of PM sizing on (a) lifetime value of CHP and (b) TES capacity and lifetime value of TES for secondary school building type

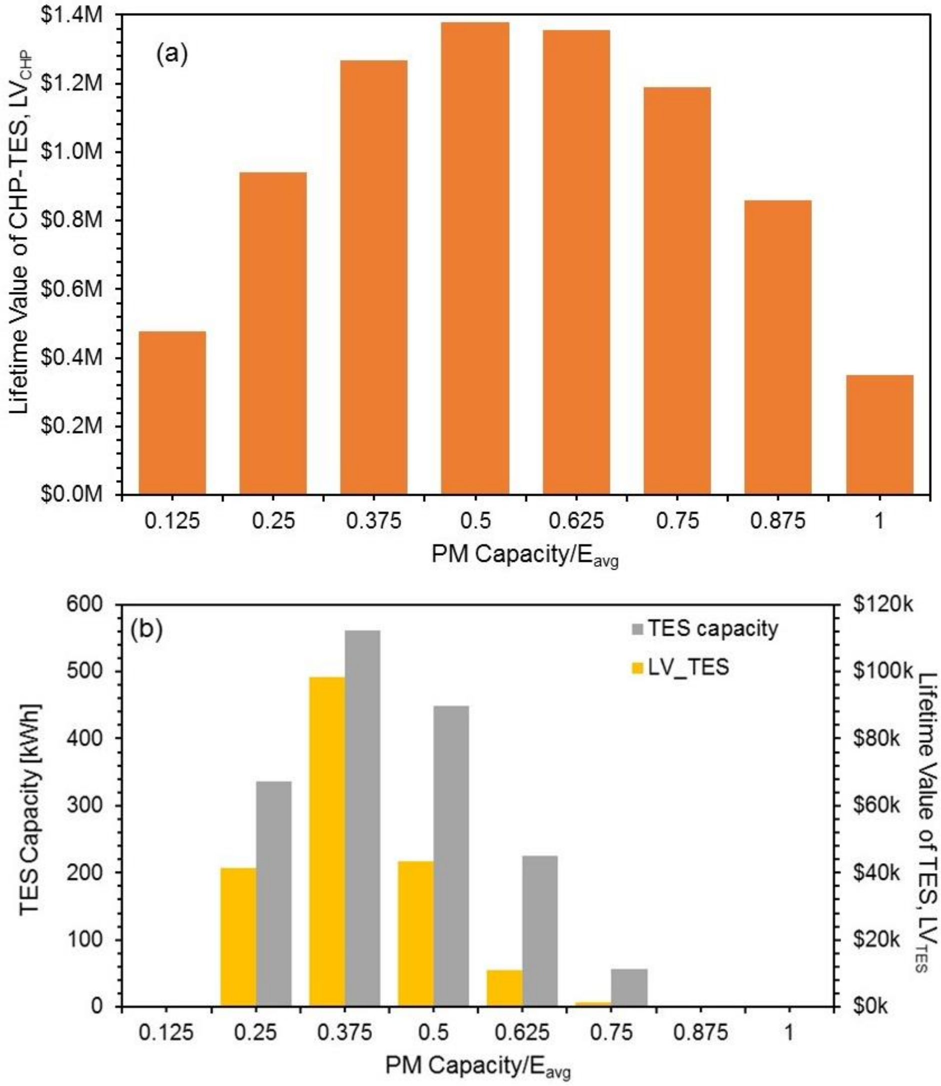


Figure 13: Impact of PM sizing on (a) lifetime value of CHP and (b) TES capacity and lifetime value of TES for large hotel building type

4.4. TES price impact on overall system economics

Recent advances in thermal energy storage, specifically high temperature TES, have led to cost reductions. In order to understand the impact of TES cost reduction in the value of CHP-TES and TES retrofits, a sensitivity analysis was completed with current state-of-the-art systems and future systems. Current systems include molten salt based and thermal oil systems that approximately cost $35/kWh and $80/kWh, respectively [14]. Future TES systems include low-cost sulfur-based TES developed by UCLA researchers ($12/kWh) [9,43] that achieves the SunShot goal of $15/kWh [29] and other molten salt systems currently being researched [29,44] that have potential to achieve DOE SunShot goal.

Assuming a PM capacity of $^{E_{avg}}/_{2}$, the lifetime value and payback period of CHP-TES and TES retrofits were evaluated for the large hotel and secondary school building types. The value of TES is low compared with the overall cost of CHP, and therefore has a relatively small impact on the overall cost of a new CHP-TES installation. However, the cost per kWh of TES can dramatically change the value of a TES retrofit. The TES cost can change the ideal TES capacity for a given building, as more expensive systems cause the ideal storage capacity to decrease. This is shown for the large hotel and secondary school building types in Figure 14a and Figure 14b, respectively. The effect of TES pricing is more significant in the secondary school case. In general, it is seen that the highest lifetime value is obtained for TES based on low-cost molten sulfur. One surprising result is that even the most expensive, mature technology – thermal oil TES – can still provide positive economics for large hotel building type. These results would suggest that adding existing molten salt TES technology to operating CHP systems could be economically beneficial to the end user.

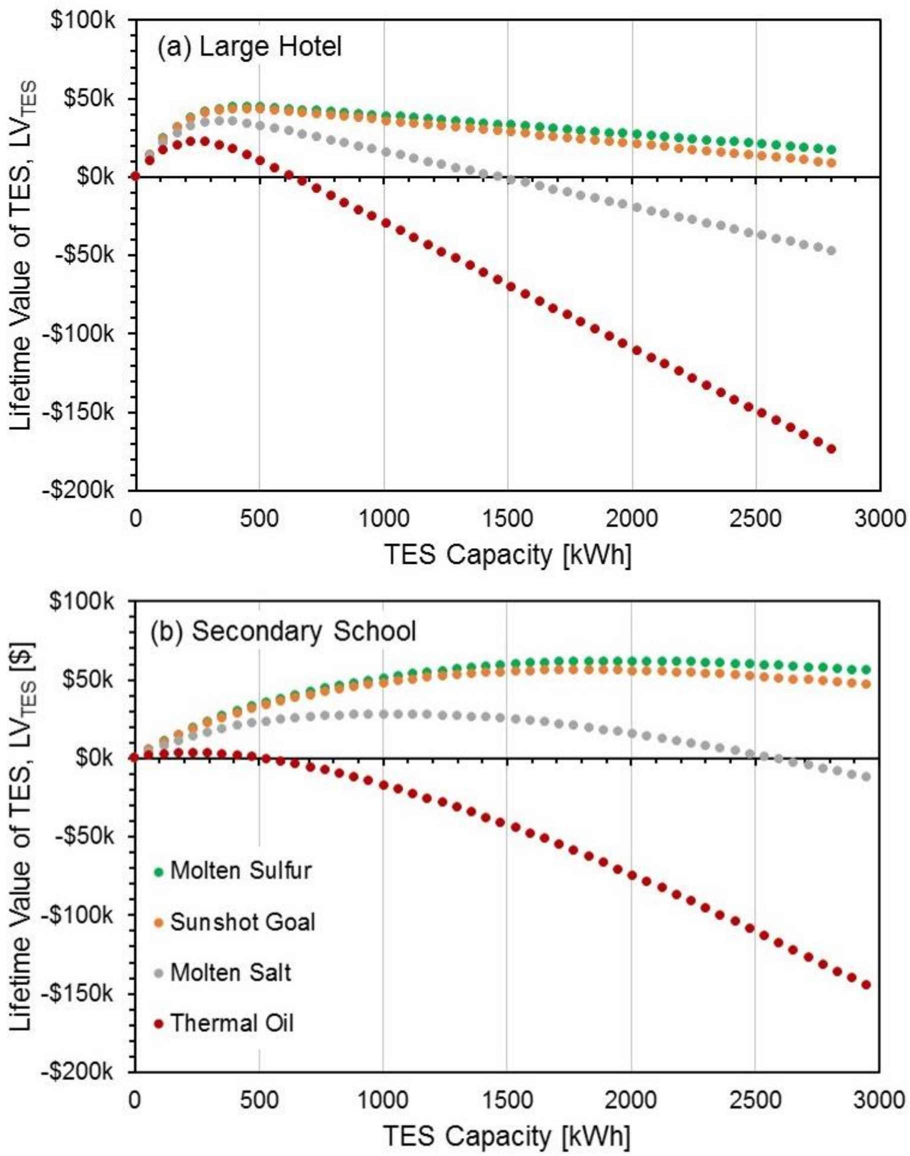


Figure 14: Impact of TES Cost and TES capacity on lifetime value of TES for (a) large hotel and (b) secondary school building types.

4.5. LA utility rates vs. California state-wide recommended rates

The results presented thus far have used the average California investor owned utility rates for 2016. However, we used Los Angeles specific weather data (3B) in the physics-based EnergyPlus [33, 45] building modeling software. In order to better understand the impact of electricity and natural gas prices, which vary between utilities within the same state, the base case of CA average utility prices was compared with Los Angeles specific utility prices. The Los Angeles region is serviced by many different utility companies, including the investor owned utilities, Southern California Edison and Southern California Gas, and the state's largest municipal district, Los Angeles Department of Water and Power. In order to evaluate the impact of region specific utilities, LADWP and SCG rates were compared directly with standard CA utility rates. The methodology and rates used in this analysis are discussed in Section 3.2.

The following results show that natural gas prices are significant in the overall economics of a CHP plant. The value in selling electricity back to the grid is lower in LADWP than in the CA average rates. This reduces the value of a larger CHP prime mover, as overproduction of electricity at the facility is not rewarded. However, the decrease in value of selling electricity to the grid was more than balanced by the 36% lower cost of natural gas for SCG commercial customers (compared to CA general rates). An important trend is how the change in utility prices incentivizes larger prime movers. Figure 15 shows the lifetime value of CHP for the secondary school and large hotel in each utility district.

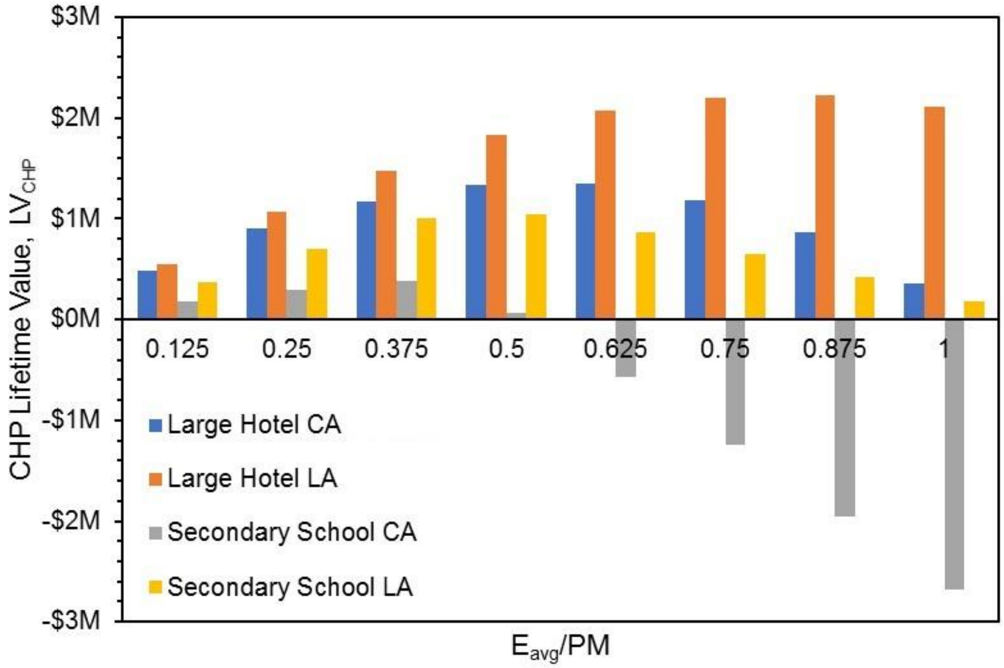


Figure 15: Variation in CHP lifetime value for secondary school and large hotel located in various utility districts with different utility rates

Larger PM capacity generally reduces the ideal size for the TES, as there are fewer instances when the building requires more heat than is generated at baseload. In the case of a TES retrofit, it is likely that the system would have been installed with the PM capacity that has the highest payback period in a CHP without TES scenario. As shown by Figure 15, this is different depending on the utility prices. Table 6 shows the ideal CHP-TES system for each utility rate. In each case the prime mover capacity increased by at least one $E_{avg}/8$ step.

Table 6: Ideal CHP capacity for different utility rates

	California State Average Rates			Los Angeles Specific Rates		
Building Type	**Ideal PM Capacity [KW]**	**LV_{CHP} [$]**	**Ideal TES Capacity [kWh]**	**Ideal PM Capacity [kW]**	**LV_{CHP} [$]**	**Ideal TES Capacity [kWh]**
Large Office	284.4	$0.70M	151.7	379.2	$2.53M	0
Hospital	606.3	$3.14M	0	727.6	$6.80M	0
Secondary School	110.6	$0.43M	1711.1	147.5	$1.06M	1239.1
Large Hotel	140.3	$1.33M	449.1	245.6	$2.22M	0
Warehouse	7.8	$0.03M	170.4	15.6	$0.11M	182.9
Super Market	110.5	$0.36M	132.6	138.1	$1.11M	0
Outpatient Healthcare	89.3	$0.79M	35.7	111.7	$1.20M	0
Full Service Restaurant	15.1	$0.08M	32.2	40.2	$0.24M	0

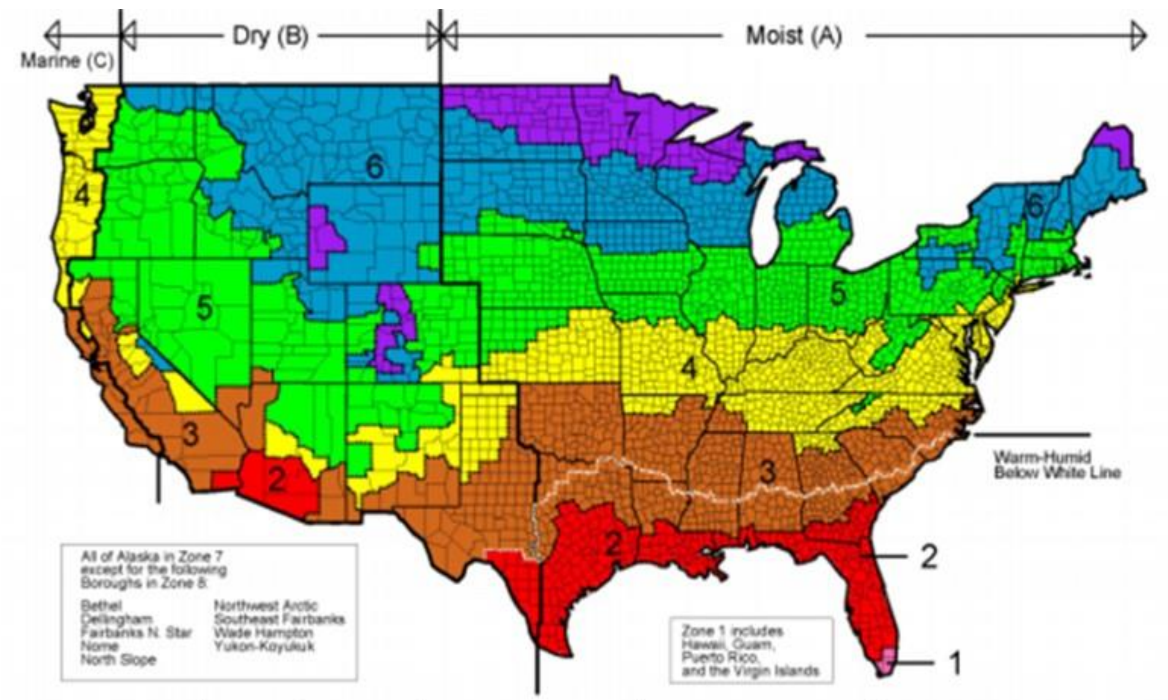
In all but two building types, the CHP-TES system in the new Los Angeles utility rate model did not include any TES; however, in the two cases that did include TES, the capacity of the energy storage system increased. These two cases, secondary school and warehouse, were selected earlier as two of the three most promising CHP-TES cases. Qualitatively, warehouses and schools tend to have more extreme variations in need for building heating compared with buildings such as hospitals and hotels, which operate and are occupied day and night. Further investigation is merited to better understand the divergence in the need for thermal energy storage.

This analysis has shown the significant impact of utility rates on the design and economics of CHP-TES. Even within the same region or state, with the same weather and building type, the system itself can become more or less economical to operate. This variation calls into focus a key concern of many potential CHP end users, which is the variability of natural gas and electricity prices. Notably, natural gas has undergone significant fluctuations in the past two decades. The nationwide average natural gas price sold to commercial consumers in January 2017 was $7.58/Mcf [46]. In January 2016, natural gas was only $6.74/Mcf, but a decade earlier in January 2006 the price was $14.16. A decade earlier in January 1996, it was $5.29. The difference in CHP economics stemming partially from a 36% variation in natural gas prices, demonstrate one of the key challenges in designing, planning, and financing a new plant. Due to the expected lifetime of CHP plants ranging from 15 to 30 years, investing heavily in new CHP systems involves non-technical challenges.

4.6. Market Comparison: Los Angeles, CA with Seattle, WA and Atlanta, GA

This study has used Los Angeles, CA as an example market, but CHP is common across the country. The previous section showed a difference not only in plant economics, but a difference in advantageous CHP plant design due to utility prices alone. For an evaluation of CHP-TES in other regions of the United States, both the utility pricing and weather play a large role in overall economics. A comparison of Los Angeles, CA with Seattle, WA and Atlanta, GA is presented here.

In the selection of comparison cities, two main factors were considered. First was the region’s “spark spread”, which is a measure of the difference in value between natural gas and electricity. California has among the largest spark spreads, as it has more expensive electricity and less expensive natural gas, while Georgia is near the average, and Seattle has one of the smallest spark spreads in the United States [30]. The second factor to consider is weather. Unlike Los Angeles, Seattle is famous for its rain and averages over 150 days of rain per year [47]. In the southeast of the United States, Georgia represents a more humid region. The DOE has broken the United States into 16 climate zones, shown in Figure 16.



Number	Climate Zone	Representative City	TMY2 Weather file location
1	1A	Miami, Florida	Miami, Florida
2	2A	Houston, Texas	Houston, Texas
3	2B	Phoenix, Arizona	Phoenix, Arizona
4	3A	Atlanta, Georgia	Atlanta, Georgia
5	3B-CA	Los Angeles, California	Los Angeles, California
6	3B-other	Las Vegas, Nevada	Las Vegas, Nevada
7	3C	San Francisco, California	San Francisco, California
8	4A	Baltimore, Maryland	Baltimore, Maryland
9	4B	Albuquerque, New Mexico	Albuquerque, New Mexico
10	4C	Seattle, Washington	Seattle, Washington
11	5A	Chicago, Illinois	Chicago-O'Hare, Illinois
12	5B	Denver, Colorado	Boulder, Colorado
13	6A	Minneapolis, Minnesota	Minneapolis, Minnesota
14	6B	Helena, Montana	Helena, Montana
15	7	Duluth, Minnesota	Duluth, Minnesota
16	8	Fairbanks, Alaska	Fairbanks, Alaska

Figure 16: Climate zone classification (Credit: Briggs et al. [45])

This model is extendable to the other climate zones to gain a full picture of CHP economics. EnergyPlus software was used to provide region specific electricity and heat usage data for each of the 8 studied building types. Table 7 shows the average electricity usage of each building type in the three US cities.

Table 7: Average electricity usage in kWh for different building types in three US cities

Region	Hospital	Secondary School	Midrise Apt	Large Office	Large Hotel	Full Service Restaurant
Los Angeles	970	296	28	758	280	40
Atlanta	1034	326	32	798	302	40
Seattle	904	260	28	688	252	36

Due to the complexity and variation of electricity and natural gas pricing strategies by region and utility companies, future work in extending this model beyond Los Angeles will require in-depth analysis of utility billing practices. However, in order to be able to have a direct comparison between regions, actual utility prices were investigated and then approximated in terms of $/kWh for electricity and $/therm for natural gas.

The Seattle City Light is a public utility, which provides electricity to the City of Seattle and parts of the metropolitan area. Based on the Medium Standard General Service Schedule, applicable to facilities with 50-1000 kW peak electric demand, a constant rate of $0.085/kWh was selected. This electricity purchase rate is an approximation of the combination of energy charge, $0.0754/kWh, demand charge, $3.63/kW (with a $0.84/meter/day minimum charge), and power factor charge, $0.0015/kVarh [48]. This study assumes natural gas is the fuel, which is not a renewable resource. It is therefore not expected that electrical overgeneration would be allowed to be sold back to the grid, and therefore excess electricity is given a $0 value [49]. Seattle's natural gas utility is Puget Sound Energy. This analysis uses Puget Sound Energy's Schedule 031 – "Commercial and Industrial General Service" rates. The delivery charge for the Schedule is $0.30627/therm plus the gas cost (sum of Supplemental Schedules 101 and 106 rates) [50]. Based on Schedule 101's total gas cost rate of $0.41065/therm, and the deferred account adjustment rate of $0.01734, the total gas cost is 0.69958/therm [51, 52].

Atlanta, GA's electric utility is Georgia Power, which classifies a large business as one with monthly maximum demand exceeding 500 kW and a medium business as one with maximum demand between 30-500 kW [53, 54]. All eight facilities fall within one of these two categories all or the majority of months. Each rate schedule has tiered energy charges. A different rate is charged for the first 3 MWh, the following 7 MWh, the following 190 MWh after that, and 200 MWh and beyond [53]. The first tier is the most expensive ($0.132655/kWh Large Business), decreasing at each step until a constant rate for the last tier of >200 MWh ($0.079109/kWh Large Business). These rates are the minimum to be charged, and do not include a variety of factors including comparative energy usage in previous months, the basic service charge, and the minimum service charge. Because the larger buildings considered here will purchase a significant amount of energy in the 10 MWh – 190 MWh tier at a price of $0.102607/kWh and the smaller buildings will purchase a significant amount of energy in the 3 MWh – 10 MWh or higher tier at a price of $0.10391 or lower, the Atlanta model approximates electricity purchases at $0.103/kWh. Similar to Seattle's utility, Georgia Power only purchases electricity from qualifying facilities which generate energy using renewable sources [55]. Therefore, the value of electricity generated by the CHP system but not used onsite is $0. One of Atlanta's natural gas utilities, Scana Energy, offers business fixed rates based on term length, including a $0.599/therm rate for a two-year term starting June 2017 [56]. This rate is only representative of the actual natural gas cost, as it is limited to businesses using less than 3,000 therms per month and does not include a monthly service charge and other potential fees. Larger natural gas customers receive quotes based on a custom site-by-site basis, so published rates were selected for this study. Table 8 shows the electricity purchase price per kWh to both purchase and sell electricity, and the price per therm to purchase natural gas.

Table 8: Approximate utility prices by region

Region	Electricity Purchase Price [$/kWh]	Electricity Selling Price [$/kWh]	Natural Gas Purchase Price $/therm
Atlanta, GA	0.103	0	0.599
Seattle, WA	0.085	0	0.69958
Los Angeles, CA	0.1638	0.024273	0.653
California (State)	0.1638	0.11	1.02

Using the energy prices in Table 8 and the energy demand profiles from Figure 16, allowed for the extension of analysis to buildings located in Atlanta and Seattle. Similar to Section 4.1, analysis of the value of TES in the case of a prime mover with capacity $E_{avg}/_2$ was completed. Figure 17 shows the TES capacity that offers the maximum lifetime value for a TES retrofit, the lifetime value itself, and the TES payback period for different building types in each of the three cities. The CA average rates in Los Angeles were used as the base case. Results in Section 4.1 identified two of the selected building types, the large hotel and secondary school, among the most promising to add value as a retrofit to existing CHP systems in Los Angeles. The other two building types selected, the large office and hospital, were among the worst. Adding TES to the hospital building did not provide favorable economics, independent of location, and is not shown in Figure 17.

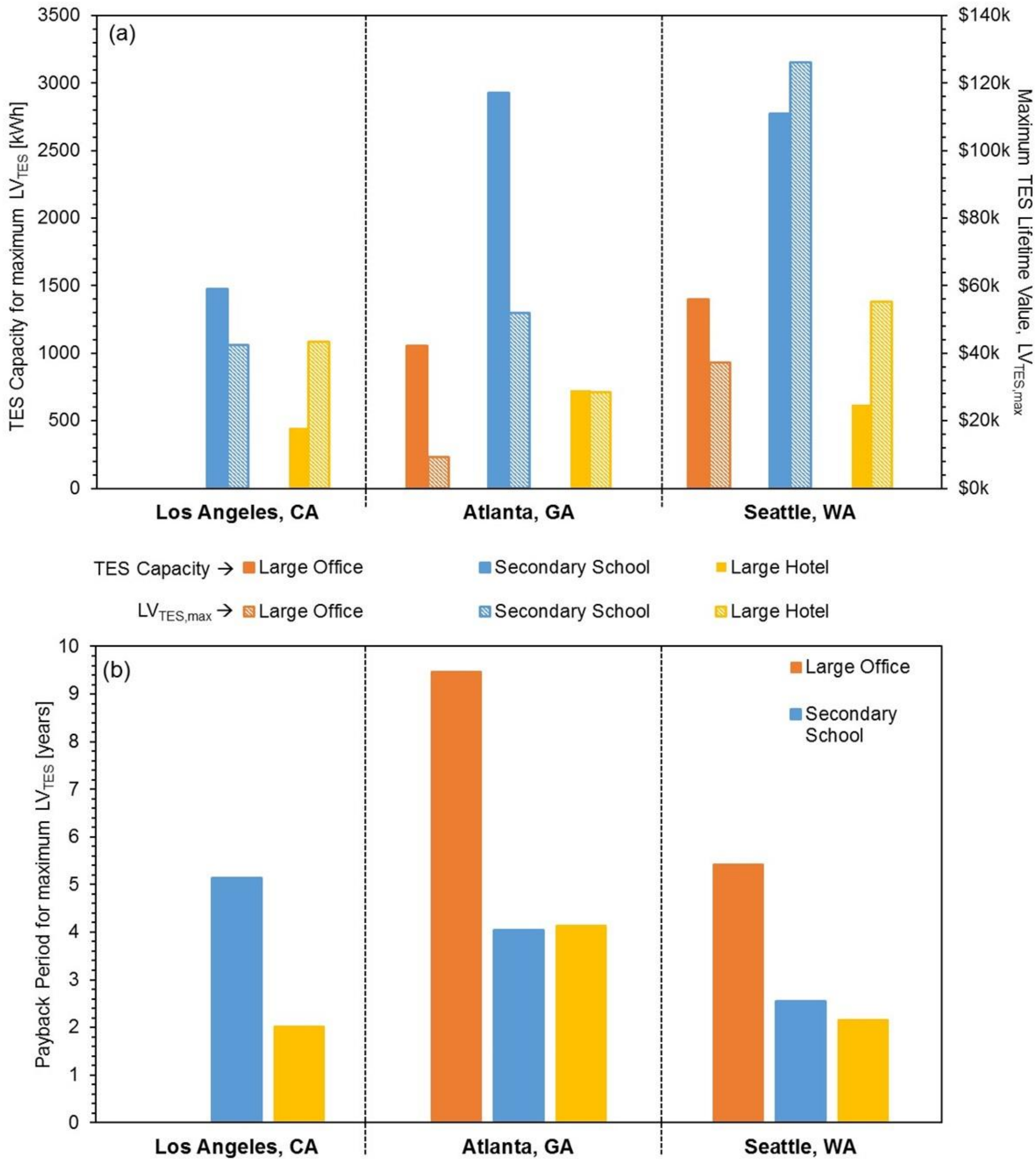


Figure 17: (a) TES capacity and (b) payback period that offers the maximum TES lifetime value for various cities

The results shown in Figure 17 demonstrate both similarities and differences between the regions. In all three regions, the hospital continues to not benefit from TES. However, in Los Angeles, the large office building does not benefit from TES, but in Atlanta and Seattle, it does. Seattle offers the best TES economics for all building types. This is largely due to the low electricity cost (approximately half that of California) and the modest natural gas price. This small spark spread means that CHP is less suitable to be built in this region, but if it is built, the economics of a TES retrofit are very good. Atlanta generally benefits from larger TES systems than the other cities tested, but the lifetime value of those systems is less. This translates to a larger upfront cost for a lower return on investment compared with Seattle and Los Angeles, but even in Atlanta, the payback period for the secondary school and large hotel's TES systems are less than 5 years.

5. CONCLUSIONS

This study considered the economic impact of Thermal Energy Storage (TES) for Combined Heat and Power (CHP) installations for eight commercial facility types. The results indicate that TES can have a meaningful beneficial impact if added to commercial CHP plants. Most of the building types have a payback period of less than five years when TES is employed with CHP. Two commercial building types were shown to be best suited for CHP-TES systems: large offices and secondary schools. The value of TES compared to the value of the CHP system is generally less than 10%, as electricity is significantly more valuable than heat. However, even a <10% increase in plant value can far exceed TES's portion of the CHP-TES system cost. Several factors were identified, which play a large role in CHP-TES economics including region and utility rates and TES costs. Given the recent advances in high temperature TES, including molten sulfur and molten salt systems, it is possible that TES will meet or exceed the $15/kWh DOE SunShot goal used in this study, and further improve commercial CHP-TES economics. This study also found approximate prime mover size and associated appropriate TES capacity for each building type, which could offer a starting point for considering a new CHP-TES installation. The work in this study has been expanded from Los Angeles, CA to Seattle, WA and Atlanta, GA, and can be extended to any other region of the United States. As future work, including cooling, through the addition of absorption chillers to the economic model, would provide insight into the combined cooling, heating, and power systems. Another avenue for future work would be including the emissions reduction due to the addition of TES to CHP systems, especially in dense urban areas and disadvantaged communities. These systems provide additional value to many commercial buildings. By incorporating the end user's monthly natural gas and electricity usage, this model could further inform the trade-off of prime mover and TES capacities to maximize lifetime value and/or minimize payback period.

6. APPENDIX A

COST OPTIMAL STRATEGIES OF HIGH TEMPERATURE THERMAL ENERGY STORAGE SYSTEMS IN COMBINED HEAT AND POWER APPLICATIONS

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COST OPTIMAL STRATEGIES OF HIGH TEMPERATURE THERMAL ENERGY STORAGE SYSTEMS IN COMBINED HEAT AND POWER APPLICATIONS

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ABSTRACT

As variable generation electricity sources, namely wind and solar, increase market penetration, the variability in the value of electricity by time of day has increased dramatically. In response to increase in electricity demand, natural gas "peaker plants" are being added to the grid, and the need for spinning and non-spinning reserves have increased. Many natural gas, and other heat source based, power plants exist as combined heat and power (CHP), or cogeneration, plants. When built for industrial use, these plants are sized and run based on heat needs of an industrial facility, and are not optimized for the value of electricity generated. With the inclusion of new, less expensive thermal energy storage (TES) systems, the heating and electricity usage can be separated and the system can be optimized separately. The use of thermal energy storage with CHP improves system economics by improving efficiency, reducing upfront capital expenditures, and reducing system wear.

This paper examines the addition of thermal energy storage to industrial natural gas combined heat and power (CHP) plants. Here a case study is presented for a recycled paper mill near Los Angeles, CA. By implementing thermal energy storage, the mill could decouple electric and heat production. The mill could take advantage of time-of-day pricing while producing the constant heat required for paper processing. This paper focuses on plant economics in 2012 and 2015, and suggests that topping cycle industrial CHP plants could benefit from the addition of high temperature (400-550°C) energy storage. Even without accounting for the California incentives associated with implementing advanced energy storage technologies and distributed generation, the addition of energy storage to CHP plants can drastically reduce the payback period below the 25 year expected

economic lifetime of a plant. Thus thermal energy storage can make more CHP plants economically viable to build.

INTRODUCTION

Due to greenhouse gas emission concerns, the recent advancements in natural gas extraction technologies, and the increasing market penetration of variable renewable resources including solar and wind power, natural gas power plants have become the largest power source in California [1]. Combined heat and power (CHP) plants have significant efficiency advantages over separate power generation-only plants and natural gas burners. This efficiency and cost effectiveness has made CHP popular in the US and internationally, with over 4,000 active CHP plants in the US alone, approximately two-thirds of which are natural gas burning.

One of the key advantages of CHP with gas turbines as the prime mover is that the heat exhausted from the turbine is generally 400°C-565°C. This temperature is high enough to be used in a wide range of industrial processes, including chemical plant operation, pulp and paper manufacturing, food processing, and oil refining. The largest application of existing CHP capacity is industrial. In California 50% of CHP capacity is for industrial usage [2].

The pulp and paper industry is the fourth largest industrial consumer of energy worldwide, consuming 5% of total industrial energy consumption [4]. This makes pulp and paper mills an important industry to consider when considering energy efficiency. The paper industry also contributes 1.1% of the world's total CO2 emissions, which similar to emissions from landfills (1.7%) and machinery (1.0%) [5]. The pulp and paper industry has grown over 60% since 1990, so the industry's impact is likely to continue to grow.

Thermal energy storage (TES) can be used to store heat at various points in a CHP plant's power cycles. TES decouples the usage of heat from the generation of electricity. This separation of electricity generation and heat usage allows the electricity to be generated when it is most valuable for the user facility or the grid that the facility is on, independent of the needs of power station.

Significant work has been published demonstrating that thermal energy storage is economically advantageous for builders of CHP plants for commercial and residential usage [3], but CHP-TES systems has not received similar attention. There are multiple reasons for the focus on non-industrial CHP. Firstly, the heat used in industrial processes is often much higher temperature than that of residential or commercial usage, making energy storage more difficult and costly. Secondly, the heat usage in homes, universities, and commercial buildings is intermittent and often offers more attractive economics for CHP-TES systems. A common approach for making CHP most economically attractive is to maximize the time in which the prime mover produces electricity.

In the case of industrial CHP and time of day dependent electricity pricing, by taking advantage of the predictability of industrial manufacturing, it can be shown that CHP-TES systems offer very significant economics over CHP without energy storage. In this scenario, it is power generation scheduling that provides the best results.

This paper uses a case study of a Los Angeles region paper plant, which does not currently have a combined heat and power plant but instead uses a natural gas burner to generate the required heat for the manufacturing process. The operators of the paper mill have considered a combined heat and power plant in the past, but have not pursued this option.

METHODOLOGY

Industrial CHP

Energy storage in CHP plants is seldom used, but is not without precedent. One example of this is Houweling Nursery CHP plant in Camarillo, CA. Heat energy is stored in water at sub-boiling temperatures to keep an elevated temperature in the tomato nurseries during the night. The pulp and paper industry has been one of the largest adopters of combined heat and power plants. Significant work has been produced regarding energy efficiency in this industry [6]. Heat used in the pulp paper industry is at a much higher temperature than that at a tomato nursery. The heat requirement for CHP plants is that they create steam in boilers to dry the product. For the pulp and paper industry, the heat used from recovery boilers is often 400°C to over 500°C. Some current examples of this are the SP Newsprint combined cycle power plant in Oregon, which uses 440°C heat for its recovery boilers, which are rated at over 480°C [7]. In Illinois, FSC Paper Company operates a CHP plant built in 1987, which uses a Mars-90 turbine. The Solar Turbines Mars-90 produce 465°C exhaust [8].

Many manufacturers produce turbines with exhausts over 500°C. Though this decreases electrical efficiency, the higher temperatures are often advantageous for high temperature industrial uses like pulp and paper mills. A partial list of Kawasaki and Siemens gas turbines presented in Table 1 has model details for the turbines that produce exhausts over 500°C.

Table 1. Siemens and Kawasaki turbines with exhaust temperatures over 500°C

Manufacturer	Model	Electrical Output (kW_e)	Exhaust Temp (°C)
Siemens	SGT-100	5,050	545
Kawasaki	GPB 70	5,122	540
Siemens	SGT-100	5,400	531
Kawasaki	GPB 70	5,769	529
Kawasaki	GPB 80	5,832	535
Kawasaki	GPB 80	6,435	524
Kawasaki	GPB 70	6,639	518
Kawasaki	GPB 70	7,184	513
Kawasaki	GPB 80	7,332	511
Kawasaki	GPB 80	7,866	507
Siemens	SGT-300	7,900	542
Siemens	SGT-400	12,900	555
Siemens	SGT-400	14,320	540
Kawasaki	GPB 180	15,180	564
Kawasaki	GPB 180	16,471	555
Kawasaki	GPB 180	18,070	544
Kawasaki	GPB 180	19,425	537
Siemens	SGT-600	24,480	543
Siemens	SGT-700	32,820	533
Siemens	SGT-800	47,500	541
Siemens	SGT-800	50,500	553
Siemens	SGT-800	53,000	551

When designing a CHP plant for industrial usage, the heat requirement dictates the sizing of the plant. The industrial facility typically focuses on their heat need to produce their product and the electricity generated is a valuable byproduct. The electricity can be used by the facility on site or sold to the grid. Currently, this translates to approximately baseload power generation, based on the hours of the facility's operation. With the introduction of TES, the heat load is still the main consideration; however, power generation can be responsive to electricity demand or pricing.

Pricing of electricity

In California, Assembly Bill 1613 created a Feed-in-Tariff for highly efficient power plants, CHP plants in particular. AB 1613 sets restrictions for eligible power plants, including [9]:

1. 60% efficient power plants at minimum
2. NOx emissions less than 0.07 lb./MWh
3. Be sized to meet eligible customer generation thermal load
4. Be cost effective, technologically feasible, and environmentally beneficial
5. Operate continuously in a manner that meets the expected thermal load and optimizes the efficient use of waste heat
6. The plant cannot exceed a 20 MW power rating

If all requirements are met, then the Feed-in-Tariff (FiT) sets up a pricing structure that rewards generation when predicted demand is highest. A key advantage of this system is that the annual electricity rate structure is announced in advance. The rates are dependent on the needs of the grid. The following pricing is based on Southern California Edison (SCE) pricing. In 2012, when the Houweling Nursery's CHP plant was first unveiled, the pricing per hour was dictated by the following pricing by time of day (TOD) as shown in Fig. 1.

The rates of the FiT are variable, and in 2015 the summer peak was significantly less dramatic. Figure 2 shows the TOD rates for 2015, also on the Southern California Edison electrical grid.

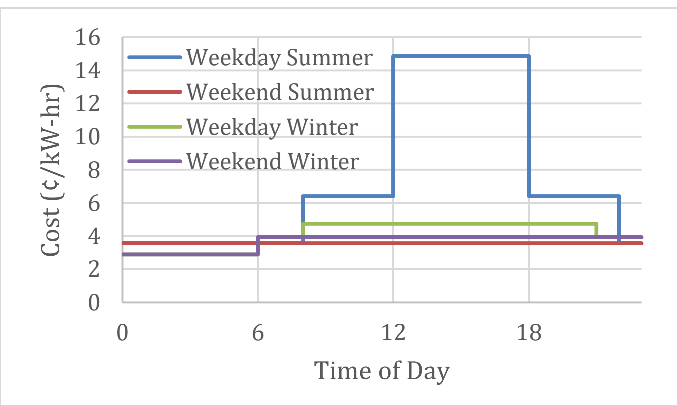


Figure 1. AB 1613 Feed-in-Tariff in 2012, SCE rates

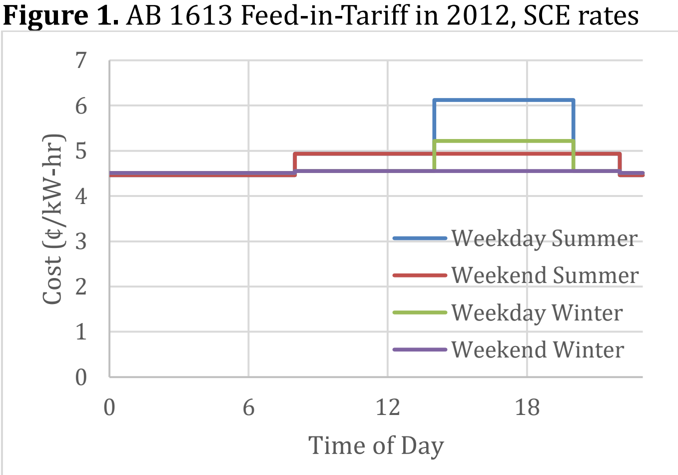


Figure 2. AB 1613 Feed-in-Tariff in 2015, SCE rates

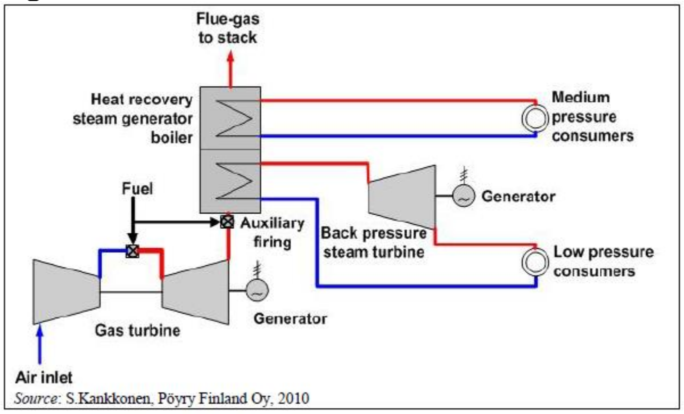


Figure 3. Schematic of a combined cycle gas turbine, combined heat and power plant for use in paper mills. [6]

Plant design

There are many designs for CHP plants. The most common are topping cycles, in which electricity is generated by a turbine, often natural gas, and then exhaust heat is used for an industrial usage. The European Union's best practices report in 2015 includes an example design, as shown in Fig. 3, with both gas and steam turbines for increased efficiency [6].

In order to clearly demonstrate the usage of thermal energy storage, a simple topping cycle is considered for this case study. This only includes the prime mover, TES, and the boiler.

Current paper mill operation

The mill purchases 28,000 MMBtu of natural gas per month, used in boilers at the facility. Partially due to startup and cool down inefficiencies, mills generally operate constantly, including nights and weekends. In sizing a power plant, the heat requirement of the mill sizes the plant components. Excessive heat generation and waste would reduce the efficiency of the plant and make it ineligible for AB 1613 Feed-in-Tariff, while a lack of heat generated would reduce the efficacy of the mill in its core function.

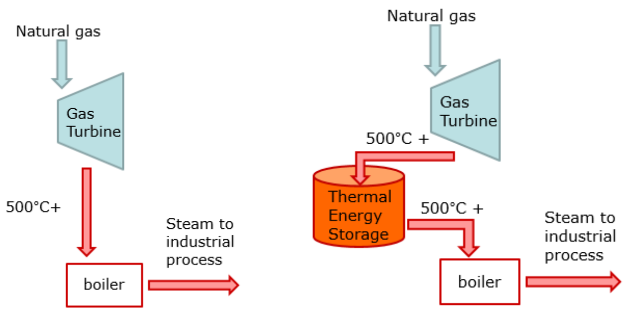


Figure 4. a) Simple topping CHP schematic. **b)** Topping CHP plant with TES

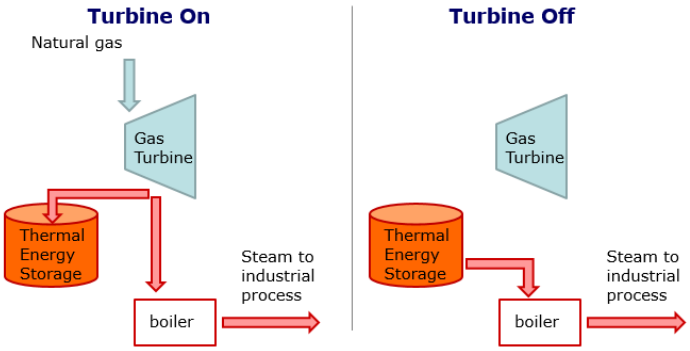


Figure 5. Charging and discharging of TES with constant heat load delivered to boiler

Topping cycle system design

In order to understand the value of various thermal energy storage strategies, a simple topping cycle power plant as depicted in Fig. 4 is modeled.

Since the mill purchases 28,000 MMBtu per month, the heat required by the industrial process can be converted to be 9 MW_t to be sent to the boiler. Though it varies by prime mover and operating conditions, electricity production is approximately 2/3 of the heat energy produced. For example, when operating under CHP conditions the Kawasaki GPB180 the ratio of electrical output to thermal output can vary from 0.58 to 0.72 [11]. Thus, in the baseload scenario (no TES), the plant is approximated to produce 6 MW_e. The heat flow to the boiler must operate under baseload conditions to keep the mill operating, thus there are two states in which CHP with TES can operate namely, Turbine On and Turbine Off as shown in Fig. 5.

Independent of the state of the turbine, the mill receives steam. In order to produce 9 MW_t baseload or 216 MWh_t per day, the gas turbine and the energy storage system must be sized to compensate. If the turbine operates over a shorter time, it must produce more electricity and heat during operation. The thermal output from the prime mover greater than the 9 MW_t required is then stored in the TES system. In the case of shorter turbine operation, the TES system must store more energy, as it must discharge over a greater amount of time. Additionally, it is assumed that the turbine is either operating at its optimal power output or is not generating at all. The thermal energy storage system, including the heat exchanger, is assumed to have losses of 10% [12, 13]. This heat exchanger effectiveness is in keeping with other high temperature (650°C) salt-based shell and tube heat exchangers, and in the range of effectiveness for salt-based compact heat exchangers [19]. According to the CSP company, SolarReserve, it is common that oil heat exchangers cause a 7% drop in cycle efficiency. Depending on temperature range, molten salt or oil heat exchangers could be used. In the case of the single tank system, the tank is in itself a heat exchanger. As such the cost of the heat exchanger is included in the cost of the TES system. The heat exchanger which uses the heat discharged from the TES system to generate heat is part of the heat recovery steam generator. The construction of the HRSG is included in the installed cost of the CHP plant in the Catalog of CHP Technologies.

Turbine Cost

By introducing thermal energy storage to a CHP plant, a larger gas turbine is required in order to generate the 216 MWh_t of heat to the end user plus the losses associated with the TES system. The EPA's Catalog of CHP Technologies was used to estimate the installed cost of gas turbines as a function of rated power output [14] and illustrated in Fig. 6.

Thermal energy storage allows the turbine to generate electricity when it is most valuable and produce a constant heat source. The increased revenue by generating electricity when is it more valuable must then be compared with the increased initial installed cost of a larger turbine and larger thermal energy storage system.

As Table 2 shows, the total plant cost increases significantly with turbine rated output, even though cost per kW decreases with size. Using this data, a simple power curve fit was used to

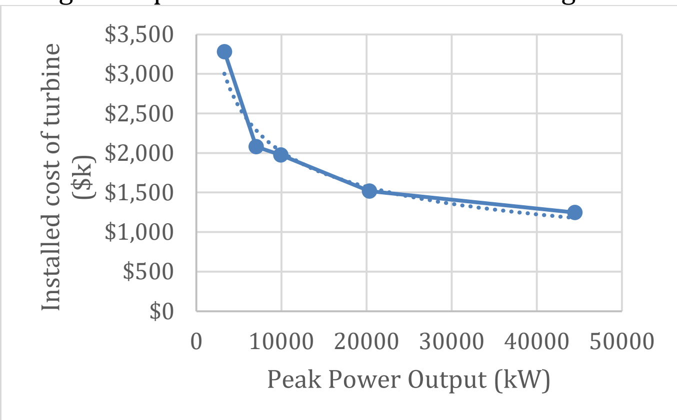


Figure 6. Total installed cost of gas turbine per kW [14]

Table 2. Installed cost of turbines for CHP [14].

Cost Component	System 1	2	3	4	5
Nominal Turbine Capacity (kW)	3,510	7,520	10,680	21,730	45,607
Net Power Output (kW)	3,304	7,038	9,950	20,336	44,488
Equipment					
Combustion Turbines	$2,869,400	$4,646,000	$7,084,400	$12,242,500	$23,164,910
Electrical Equipment	$1,051,600	$1,208,200	$1,304,100	$1,490,300	$1,785,000
Fuel System	$750,400	$943,000	$1,177,300	$1,708,200	$3,675,000
Heat Recovery Steam Generators	$729,500	$860,500	$1,081,000	$1,807,100	$3,150,000
SCR, CO, and CEMS	$688,700	$943,200	$983,500	$1,516,400	$2,625,000
Building	$438,500	$395,900	$584,600	$633,400	$735,000
Total Equipment	$6,528,100	$8,996,800	$12,214,900	$19,397,900	$35,134,910
Installation					
Construction	$2,204,000	$2,931,400	$3,913,700	$6,002,200	$10,248,400
Total Installed Capital	$8,732,100	$11,928,200	$16,128,600	$25,400,100	$45,383,310
Other Costs					
Project/Construction Management	$678,100	$802,700	$1,011,600	$1,350,900	$2,306,600
Shipping	$137,600	$186,900	$251,300	$394,900	$674,300
Development Fees	$652,800	$899,700	$1,221,500	$1,939,800	$3,312,100
Project Contingency	$400,700	$496,000	$618,500	$894,200	$1,526,800
Project Financing	$238,500	$322,100	$432,700	$899,400	$2,303,500
Total Installed Cost					
Total Plant Cost	$10,839,800	$14,635,600	$19,664,200	$30,879,300	$55,506,610
Installed Cost, $/kW	$3,281	$2,080	$1,976	$1,518	$1,248

approximate all subsequent installed plant costs, where P is the net power output in kW.

$$Cost\left(\frac{\$}{kW}\right) = 5.530 \times 10^4 \times P^{-0.35955}$$

The storage system costs used are based on the elemental TES, which is priced at $11.2/kWh [15]. The cost of various installed systems are shown in Table 3. This takes into account losses associated with including a TES system.

Table 3. Component and complete installed system costs

Generation time	Power output	Turbine Cost	TES Cost	Total Installed Cost
	kW	$M	$M	$
Baseload	6000	$14.5	$0	$14,535,906
15-hour	10560	$20.9	$1.0	$21,875,526
13-hour	12184.62	$22.9	$1.2	$24,101,118
9-hour	17600	$29.0	$1.7	$30,620,877
6-hour	26400	$37.5	$2.0	$39,539,911
3-hour	52800	$58.5	$2.3	$60,852,753
1-hour	158400	$118.3	$2.6	$120,829,428

Revenue from Electricity Generation

Using the 2012 AB 1613 Feed-in-Tariff rates by Southern California Edison, as in Figure 1, and assuming that the turbine runs during the highest revenue hours available, the total revenue per year can be calculated, which is presented in Table 4. It should be noted that for this FiT, summer is four months and winter accounts from the remaining eight.

Table 4. Electricity revenue sold to grid at 2012 SCE rates

	Summer	Winter	Full Year	
System	$/kWhr	$/kWhr	$/kWhr	$/year
Baseload	0.062	0.0399	0.047	$2,487,788
15-hour	0.079	0.0444	0.056	$3,225,946
13-hour	0.082	0.0451	0.058	$3,325,310
9-hour	0.094	0.0451	0.062	$3,557,967
6-hour	0.114	0.0451	0.068	$3,936,034
3-hour	0.114	0.0451	0.068	$3,936,034
1-hour	0.114	0.0451	0.068	$3,936,034

Cost of Natural Gas

The final component in the economic viability of TES in combination of TES plants is the price of natural gas (NG). In the current mill, natural gas is used only in the boiler. In a CHP plant, the gas is also used to power the turbine, and as a result more natural gas is used. Due to the recent volatility of natural gas costs, various scenarios must be considered.

Large natural gas buyers like paper mills in California purchase natural gas at industrial prices. Transport to the facility is estimated at $0.80 per MMBtu. Industrial natural gas prices published by the US Energy Information Agency is tabulated below in $/Mcf, which agree closely with the actual price paid by the paper mill. One million British Thermal Units (1MMBtu) is equivalent to 1.028 thousand cubic feet of natural gas (1 Mcf), or 1 MMBtu = 1.028 Mcf.

Table 5. Natural gas prices for industrial buyers in $/Mcf [16]

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2001	8.84	7.21	6.30	6.08	5.46	4.75	4.10	3.99	3.50	3.18	3.88	3.69
2002	4.05	3.70	3.78	3.64	4.07	3.86	3.80	3.62	3.89	4.18	4.72	4.92
2003	5.65	6.40	8.27	5.96	5.78	6.59	5.69	5.28	5.32	4.93	5.19	5.90
2004	6.72	6.52	5.97	6.06	6.34	6.82	6.41	6.36	5.68	6.03	7.64	7.54
2005	7.06	7.15	7.12	7.71	7.19	6.91	7.40	7.98	10.18	12.06	12.11	11.17
2006	10.85	9.38	8.24	7.93	7.63	6.92	6.78	7.36	7.21	5.62	7.74	8.23
2007	7.36	8.25	8.42	8.14	8.11	7.92	7.51	6.72	6.28	7.06	7.87	8.18
2008	8.29	8.96	9.61	10.03	11.35	12.11	13.06	10.10	9.13	8.10	7.34	7.86
2009	7.50	6.43	5.69	5.05	4.40	4.56	4.68	4.38	3.89	4.82	5.44	5.97
2010	6.93	6.76	6.01	5.12	5.08	5.04	5.49	5.37	4.61	4.73	4.60	5.50
2011	5.66	5.77	5.21	5.34	5.21	5.21	5.05	5.21	4.84	4.71	4.64	4.59
2012	4.58	4.19	3.71	3.21	3.02	3.34	3.60	3.83	3.56	3.94	4.46	4.73
2013	4.58	4.54	4.59	4.95	5.00	4.90	4.47	4.31	4.36	4.36	4.62	4.97
2014	5.62	6.58	6.39	5.78	5.69	5.42	5.36	4.90	4.96	4.97	4.97	5.54
2015	4.76	4.60	4.35	3.86	3.50	3.69	3.68	3.73	3.53	3.46		

The natural gas pricing information presented in Table 5 illustrates the high volatility of expected NG cost. The average price of natural gas, obtained from Table 5, since January 2012 is \$4.38/MMBtu. Averaging over the last 12 months of available data, the NG price is \$4.02/MMBtu. For an initial estimate, allowing the pricing to be \$4.20/MMBtu at the border, plus the \$0.80 cost of NG transportation, makes the cost of NG to the customer to be \$5.00. Knowing that the mill currently purchases 28,000 MMBtu each month for the boilers and assuming \$5 NG, the baseline gas cost is \$1,679,595 annually.

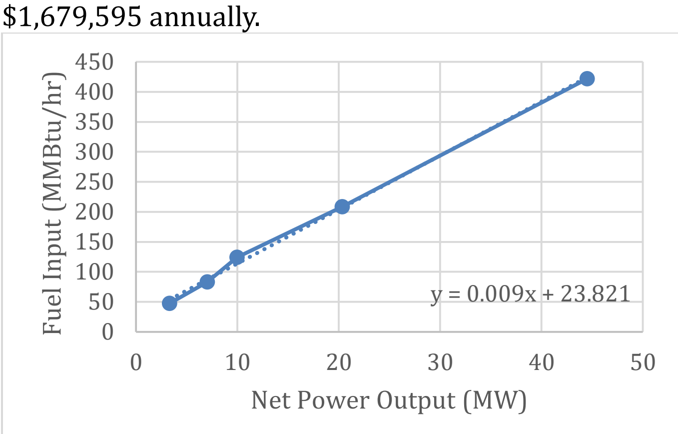


Figure 7. Fuel Input per hour for turbines of electrical capacities 4 MW to 40 MW

A linear fit was used to approximate the fuel input required per hour for the turbine power outputs listed in Table 3 as shown in Fig. 7.

RESULTS AND DISCUSSIONS

Combining the effects of electrical revenue per kilowatt and amount of electricity generated, the cost of natural gas and the amount of natural gas required, the amount of natural gas required by status quo operation, and the installed cost of the entire plant, gives the full payback period. The difference between the natural gas purchased for CHP operation and that needed in the status quo is referred to as Δ NG.

$$Payback\ Period\ [yr] = \frac{Installed\ Cost\ (\$)}{Electric\ Rev\ \left[{}^{\$}/_{yr}\right] - \Delta NG\ \left[{}^{\$}/_{yr}\right]}$$

The lifetime of new CHP plants is estimated a few ways. Though the current average lifetime of natural gas power plants coming offline recently has been 48 years, the expected technical lifetime of a CHP plant is 30 years and the economic lifetime is 25 years [17, 18]. The payback term and economic lifetime return under 2012 FiT conditions are shown in Figures 8 and 9, respectively.

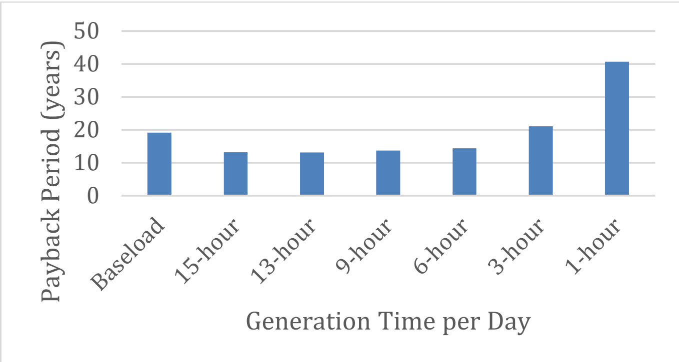


Figure 8. Payback period for various operating periods (2012 FiT)

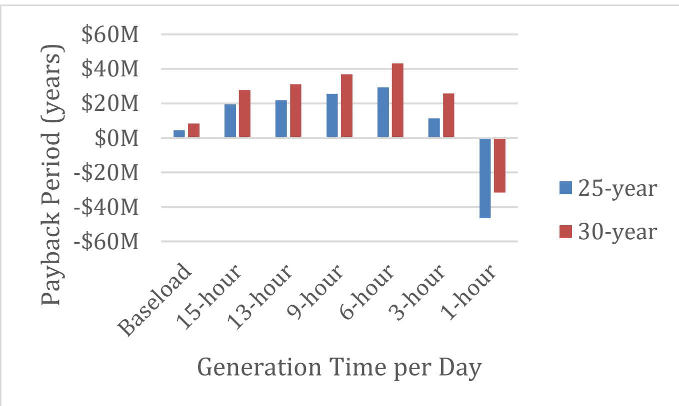


Figure 9. Revenue under different turbine operating periods and plant lifetimes (2012 FiT)

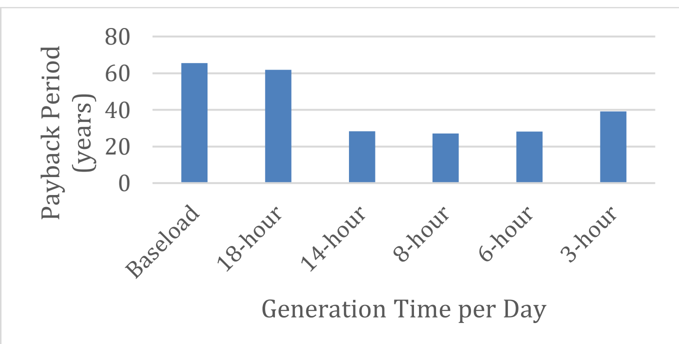


Figure 10. Payback period for various operating periods (2015 FiT)

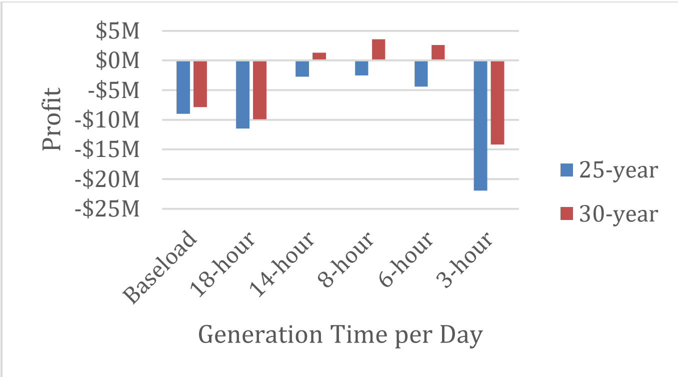


Figure 11. Revenue under different turbine operating periods and plant lifetimes (2015 FiT)

The fastest payback period is 13.11 years, in the 13-hour electricity generation case (Fig. 8). The greatest lifetime profit is in the 6-hour generation case at approximately $28.3 million in profit over the 25 year economic lifetime (Fig. 9).

As shown in Figure 2, the benefit of generating on peak in 2015 was significantly less than in 2012. The average revenue per kW was also significantly reduced. Using similar analysis as in the 2012 case, but using different generating hours due to the difference in the Feed-in-Tariff peak hours, resulted in the following payback periods and lifetime profits as shown in Figs. 10 and 11, respectively.

In the 2015 case, the shortest payback period is 27.1 years (Fig. 10), which is longer than the 25 year economic lifetime. In 2012, building a baseload CHP plant would have been an attractive option, however using 2015 pricing information it is clear that building a baseload CHP system is an unattractive risk. Despite these large difference in the economics of a baseload CHP plant, in both cases implementing thermal energy storage improves the economics of building the power plant.

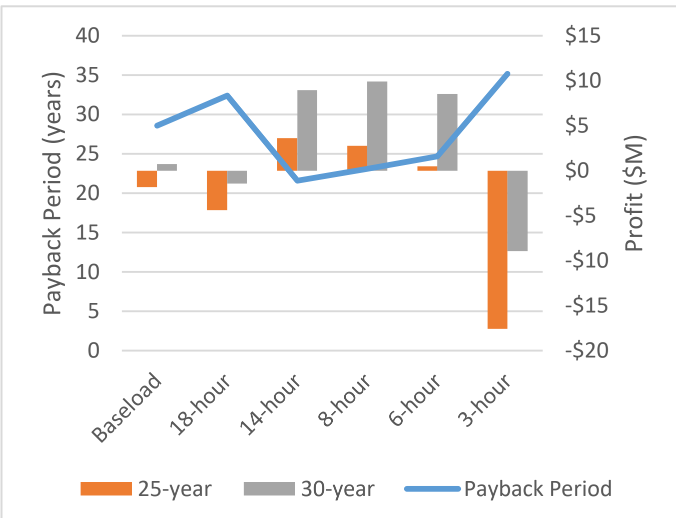
This system requires high temperature thermal energy storage in order to produce adequate steam to the mill. This system uses data from UCLA's TES system currently in development. For a more general case, using the DOE SunShot goal for the year 2020 of $15/kWh could be appropriate and changes the economics in a relative minor way. The initial cost of the 2015 TES systems are presented in Table 6.

Table 6. Installed cost of TES systems

System	UCLA TES	SunShot goal
Baseload	$14,535,906	$14,535,906
18-hour	$19,242,001	$19,467,721
14-hour	$22,929,598	$23,305,798
8-hour	$33,000,655	$33,602,575
6-hour	$39,539,911	$40,217,071
3-hour	$60,852,753	$61,642,773

Another important consideration is the large volatility of NG prices. By keeping all other parameters the same, using the 2015 Feed-in-Tariff pricing, and only changing the NG price, the extreme effect of these fluctuations is isolated. Using the most recent data available (October 2015), $3.37/MMBtu, results in the payback period and revenue shown in Figure 12. Figure 13 shows the impact of the average NG price in 2008, the first year of AB 1613, during which the average NG price was $9.40/MMBtu.

Figure 12. Payback period and lifetime profit using $3.37/MMBtu NG and 2015 FiT



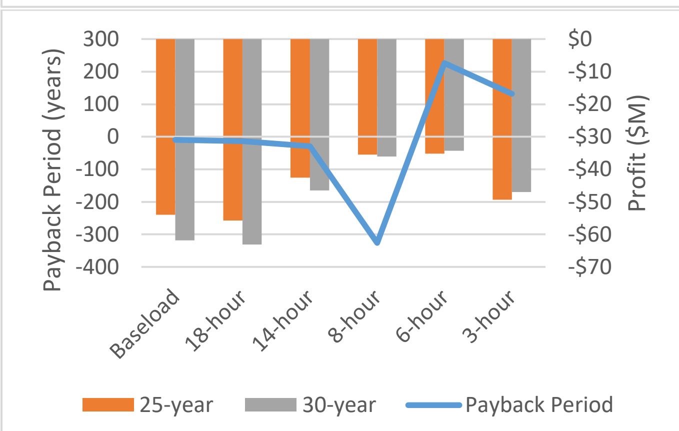


Figure 13. Payback period and lifetime profit using $9.40/MMBtu NG and 2015 FiT

Figure 13 does not give reasonable results because the spark spread is not adequate to make generating electricity profitable in most of the scenarios. The price of natural gas plays a very large role in the economics of new industrial CHP plants, and the commodity's volatility causes additional risk in building new plants.

The economics of CHP have changed drastically with the recent drop in natural gas prices and fluctuations in electricity pricing. It is common in industry that a plant with a payback period of 10 years or less before government incentives to be worth serious consideration of building, as the engine manufacturer Cummins mentions in a 2008 CHP brochure [20]. California, which is related to this case study, has incentives such as the Self Generation Incentive Program, which can offset a significant amount of the costs of engine and turbine CHP systems, as well as advanced energy storage technologies. As shown in Table 5, natural gas prices were more than twice as high in 2008 compared with 2012, and over three times greater than in 2015. Over a long term view of the 25-, 30-, or 48-year lifetime of a CHP plant, the economics of CHP is dependent on a return to normalcy in commodity prices or increasing incentives for low-emissions demand responsive power sources.

CONCLUSIONS

Through a very simplified model for topping-cycle industrial CHP with TES, this case study suggests that by sizing the turbine, taking advantage of high temperature TES, and timing electricity generation based on the Feed-in-Tariff could provide attractive economics compared to base case without any thermal energy storage. There are many important details, which have been crudely approximately in this study, including TES losses, turbine efficiency, and turbine startup losses. This study also ignored the AB 1613's restriction of a 20 MW capacity maximum, which would limit the turbine to run for a minimum of approximately 7 hours. The aforementioned assumptions will be relaxed and a refined model will be developed as part of the future work to investigate the techno-economics of thermal energy storage addition to industrial natural gas combined heat and power (CHP) plants.

ACKNOWLEDGMENTS

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