Thermal Energy Storage Contribution to the Economic Dispatch of Island Power Systems

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Abstract—In this paper the provision of flexible generation is investigated by extracting steam from Rankine-cycle power stations during off-peak demand in order to charge thermal tanks that contain suitable phase-change materials (PCMs); at a later time when this is required and/or is economically effective, these thermal energy storage (TES) tanks can act as the heat sources of secondary thermal power plants in order to generate power, for example as evaporators of, e.g., organic Rankine cycle (ORC) plants that are suitable for power generation at reduced temperatures and smaller scales. This type of solution offers greater flexibility than TES-only technologies that store thermal energy and release it back to the base power station, since it allows both derating but also over-generation compared to the base power-station capacity. The solution is applied in a case study of a 50-MW rated oil-fired power station unit at the autonomous system of Crete. The optimal operation of the TES system is investigated, by solving a modified Unit Commitment – Economic Dispatch optimization problem, which includes the TES operating constraints. The results indicate that for most of the scenarios the discounted payback period is lower than 12 years, while in few cases the payback period is 5 years.

Index Terms—Economic dispatch, energy-management, energy storage, flexible energy system, flexible generation, generation integrated energy storage, phase change materials, smart grids.

NOMENCLATURE

- $P_{i}^{t}$: Electrical output of main turbine at time $t$.
- $P_{i}^{t}$: Active production of unit $i$ at time $t$ in the range $[P_{i}^{t,min}, P_{i}^{t,max}]$.
- $P_{inter}^{t}$: Power imported through the interconnection at time $t$.
- $P_{Load}^{t}$: Load at time $t$.
- $P_{out}^{t}$: Endoreversible electrical power with maximum value $P_{out}^{max}$ at time $t$.
- $P_{RES}^{t}$: Power produced by RES at time $t$.
- $P_{StorSR}^{t}$: Spinning reserve availability that can be provided by the storage system at time $t$.
- $Q_{boil}^{t}$: Energy Produced by the boiler, within the range $[Q_{boil}^{min}, Q_{boil}^{max}]$ at time $t$.
- $Q_{cond}^{t}$: Energy diverted from the boiler to the condenser within the range $[Q_{cond}^{min}, Q_{cond}^{max}]$ at time $t$.
- $Q_{el}^{t}$: Thermal energy diverted from the boiler to the main turbine $Q_{el}^{min} - Q_{el}^{max}$ at time $t$.
- $Q_{in}^{t}$: Thermal energy input rate.
- $Q_{stor}^{t}$: Stored energy $Q_{stor}^{min} - Q_{stor}^{max}$ at time $t$.
- $S$: Entropy.
- $SMPr^{t}$: The Marginal Price of the Greek Mainland System at time $t$.
- $SU_{i}^{t}$: The shutdown/startup cost of power unit $i$ at time $t$.
- $T_{a}$: Ambient temperature.
- $T_{st}$: Storage tank temperature.
- $VOLL$: Value of Load Loss.
- $W_{cycle}$: Generated electrical power.
- $x(t)$: Binary variable that is equal to 1 when the steam power unit is in operation.
- $y(t)$: A binary variable that is equal to 0 when TES operates in generating mode.
- $\eta_{C}$: Carnot efficiency.
- $\eta_{N}$: Novikov efficiency.
- $\eta_{th}$: Thermal efficiency.

I. INTRODUCTION

NEW challenges in the planning and economic operation of power systems have to be considered by the increasing installed capacity of distributed generation (DG). In Greece, the penetration of Renewable Energy Sources (RES) is mainly launched by highly volatile wind and photovoltaic (PV) power plants. The intermittent operation of RES increases the need for flexibility and load-following capabilities in order the system operators to manage the flow, security and quality of electricity to the consumers [1], [2]. In particular, in Greece,
power transfer between the mainland and Aegean islands as well as Crete island is a key concern, e.g. Crete-Greek system can be seen as a two-area system with dominant transfers mainly due to wind power from Crete to Greece. Compliance to environmental directives 2010/75/EU (IED) [3] and 2015/2193/EU (MCPD) [4] require the decommissioning of a number of local units leading to generating capacity shortage. This will potentially rise issues for the economic operation of certain types of the existing power stations in mainland and islands. Therefore, economical operation and planning of the mainland and islands power systems must be carefully investigated by making sure that the increased load demand and supply can be matched even under high penetration levels of intermittent RES.

In this paper, we consider a flexible generation-integrated Energy Management System (EMS) featuring the integration of thermal energy storage (TES) based on phase-change materials (PCMs) into an oil-fired power station case-study. The proposed EMS solution can be similarly applied with few modifications to other types of Rankine-cycle (e.g., coal-fired, nuclear etc.) power plants, and even in principle to gas-turbine and combined cycle power plants. The latter are of interest since they are characterized by flexible unit dispatch and load following operations [5], while also having the highest efficiencies of all thermal power plants with efficiencies often in excess of 60% [6] (in fact, it has been suggested that the efficiency of such plants can reach values up to 65% from improvements to gas-turbine technology and optimization of the heat recovery steam generator [7]). Nevertheless, application of our proposed EMS solution to gas and combined cycles is less trivial and needs special treatment, so it is considered beyond the direct scope of the present work.

In more detail, it is proposed here that during off-peak demand, steam can be extracted from such power stations for the charging of an array of thermal tanks that contain suitable PCMs. At a later time, when this is required and/or economically favorable, the charged TES tanks can act as heat sources of secondary thermal power plants in order to generate power in addition to that of the base power station, for example by acting as the evaporators of organic Rankine cycle (ORC) plants. ORC plants are of particular relevance in this context as they are suitable for power generation at reduced temperatures and smaller scales [8]. The study of this type of solution is of interest as it offers greater flexibility than TES-only solutions.

The use of TES technology based on PCMs is nowadays common practice in some large-scale power-generation applications. Such TES, without secondary power generation as is mentioned above, is for example regularly integrated in concentrated solar power (CSP) plants in order to support this intermittent energy source and also to allow load-following operations. In fact, the integration of TES in CSP can increase the solar share (fraction of total energy provided by solar) by as much as 47%, to over 70% on sunny days [9]. The challenge concerning the development and practical integration of TES systems into conventional power plants (oil-fired, nuclear, coal, etc.) can be strongly facilitated by harnessing the CSP experience.

Coal-fired power stations often represent a large share of the power delivered to grids, and therefore their management can be used to improve grid stability with great effectiveness in the scenario of a significant generation of intermittent renewable electricity. An interesting option, for example, involves the conversion of heat to electricity at peak-demand times by integrating waste heat in the feedwater preheating systems of such plants, as investigated by Roth et al. [10] in a 390-MW coal-fired power plant. Furthermore, TES integration into coal-fired power plants is often proposed as a promising solution for enhanced flexibility and load-following operations as in Richter et al. [11]. The present study also considers generation-integrated TES, and is readily extended to coal-fired power stations.

The present work goes beyond a previous study [11] that investigated thermal integration with stores in the preheating routes of power stations, by: (i) considering different configurations and strategies for integrating thermal energy stores in power stations; (ii) developing load following operations directly applicable to Rankine-cycle power stations, and in particular oil-fired power stations; (iii) considering the conversion of the stored thermal to electrical power for connection to the transmission networks. In more detail, we have attempted to:

- Understand the variations to the operation of power stations from a thermodynamic perspective when integrating different TES strategies (Sections III, IV and V), and quantify the potential resulting variations in generation capacity between peak and off-peak times.
- Account for the performance of the secondary plants that later convert the stored thermal energy to electricity. Surprisingly, the use of such secondary plants within the context of integrated TES in power stations has not been studied in this way before.
- By means of an economic analysis (Section V), proceed finally to estimate the potential profits from the operation of the proposed EMS within a framework based on the optimal operation of the TES system by solving a modified Unit Commitment – Economic Dispatch optimization problem, which includes the constraints and techno-economic characteristics of the TES.

II. Concept Description

We begin with a brief overview of the thermodynamic cycle of the particular oil-fired power plant (case study) at the center of the present effort. Fig. 1 presents an outline of the main components of the existing oil-fired power station operating in the autonomous power system of Crete that is used as a case study together with the corresponding thermodynamic processes. Referring to this figure, the working fluid undergoes the following processes [12], [13]:

- Process 1-2: Expansion of the working-fluid vapour (steam) through the high-pressure turbine (HPT) and heat is converted to work \( W_{el_1}^t \) at time \( t \);
- Process 2-3: Expansion of the working fluid through the low-pressure turbine (LPT) to the condenser pressure and heat is converted to work \( W_{el_2}^t \) at time \( t \). The total work \( W_{el}^t \) is the sum of the work \( W_{el_1}^t \) and the work \( W_{el_2}^t \).
• **Process 3-4:** Heat transfer from the working fluid as it flows at constant pressure through the condenser with saturated liquid at State 4;
• **Process 4-5:** Pressurization of the saturated working-fluid liquid in the feed pump;
• **Process 5-1:** Isobaric heat addition to the working fluid as it flows at constant pressure through the boiler to complete the cycle within a range of minimum stable generation (technical minimum load) and maximum output \( (Q_{\text{boil}}^{\text{min}}, Q_{\text{boil}}^{\text{max}}) \) at time \( t \).

The thermal input to the power station is 123 MW (128 MW fuel input), the electrical power output is 50 MW and the thermal efficiency of the Rankine power cycle is 39.2%. The isentropic efficiencies of the high-, and low-pressure turbines are 70% and 75% respectively. The electrical power consumption of the feedpump is 0.88 MW and its isentropic efficiency is 78% [14].

We consider the integration of Thermal Energy Storage (TES) into this power station with the aim of modulating its electrical power output and reducing its minimum stable generation as illustrated for example in Fig. 2. At base conditions, the power output of the plant is assumed constant at the plant’s rated power (i.e., at 50 MW; red line in Fig. 2). In our proposed Energy Management System (EMS), the power station operator is informed, e.g., one day ahead, of the hourly electricity-exchange prices in the transmission network. An automated EMS then makes decisions for the charging-discharging of the TES stores by solving a modified Unit Commitment – Economic Dispatch optimization problem.

As an example, Fig. 2 illustrates a scenario in which the thermal stores are charged twice per day, at 02:00 and 12:00 (signified by dips in the green line). After charging the tanks, these are considered autonomous units which are connected to the transmission grid as distributed generators in the same or in a separate bus from the one the main power station is connected to. The tanks are coupled to and provide thermal energy to secondary power plants, which can be ORC plants due to the feasibility of this technology in this particular application, although it is noted that much of our analysis (Section III, Eqs. (1) to (4)) is technology agnostic.

In particular, a number of technologies have been reported as being suitable for power generation from low-to-medium temperature heat [REFS]. This conversion can be achieved by the employment of technologically and commercially mature technologies, such as ORC [REFS] and Kalina cycle [REFS] engines, but also early-stage technologies that are currently under development, such as thermoacoustic [REFS] and thermofluidic [REFS] heat engines. With respect to the latter, which are less well-known, the Non-Inertive-Feedback Thermofluidic Engine (NIFTE) [REFS] and Up-THERM heat converter [REFS] are two so-called two-phase thermofluidic oscillators (TFOs) that have attracted recent attention, and have been shown to be competitive with established technologies, such as ORCs. Nevertheless, ORC technology is more established, commercially available and is mentioned in the present study as a potential technology that can correspond to the secondary power plants. ORC systems are suitable for heat conversion at temperatures up to 400–500°C and at power output scales up to tens of MW. Important advantages from their (relatively) simple architecture and low complexity, the use of simple and well-established components, and broad applicability compared to alternatives.

Furthermore, it is noted that in this work we do not consider the case of cogeneration, i.e., the direct use of the heat that has been stored without conversion. Although it is acknowledged that this solution will incur lower costs, there are complications in identifying suitable end-users that require this heat year-round, especially in hot climates such as Crete, and there are well-known, non-trivial practical and also policy challenges in over-the-fence heat delivery and use; therefore, the present work focuses on electricity generation only.
The secondary plants are shown here indicatively as producing approximately 20 MW of electrical power during peak demand (refer to Section III, Table I). The TES tanks are discharged at 08:00 and 18:00 (peaks in the green line). Such a scenario with flexible operation of power stations and in particular of oil-fired power stations, especially in response to the hourly prices, can play a crucial role in the accelerated penetration of renewable energy sources into the grid. The detailed consideration of this scenario forms the principal motivation behind our work.

III. POWER STATIONS WITH INTEGRATED THERMAL ENERGY STORAGE

The charging characteristics of thermal energy stores depend strongly on the materials used. In the investigated TES schemes, materials selection is determined by the temperature at which steam is extracted at various points from the case-study oil-fired power station. The following possibilities for steam extraction are considered: (i) before the high pressure turbine (HPT) at 530°C and 100 bar or from the glands of the high pressure turbine and/or (ii) before the low pressure turbine (LPT) at 198°C and 2.4 bar. In this study we investigate the TES schemes for steam extraction before the high pressure turbine, since the thermal stored energy is the maximum. The design of the TES tanks has been based on shell-and-tube heat exchangers, with the steam condensing as it flows through the tubes and suitable PCMs in the shells. In both of the above cases, the steam comes into contact with the inner surfaces of the tubes, whose temperatures are below its condensation temperature. Therefore, the design of the TES tanks becomes essentially the design of steam condensers. Several methodologies have been proposed in the literature for designing such condensers [15]. Here we assume that the conditions (i.e., mass flow rate, diameter) are such that downwards annular flow is established in the tubes [16], [17]. This flow regime permits complete wetting of a tube’s inner surfaces, such that the steam does not condense directly on the solid wall but over the surface (interface) of a liquid film [17].

As illustrated in Fig. 3, the working fluid undergoes the following series of processes:

- **Process 1-a:** Diversion of part of the working fluid (superheated steam) flow upstream of the high pressure turbine \( Q_{\text{cond}}^t \) at time \( t \) followed by isobaric heat rejection and condensation of the steam flow, while charging a first PCM thermal-tank (Thermal Tank 1);
- **Process a-b:** Isobaric heat rejection of the working fluid (water), while charging a second PCM thermal-tank (Thermal Tank 2); The total thermal energy stored in both thermal tanks at time \( t \) is denoted as \( Q_{\text{stor}}^t \);
- **Process b-5:** Pressurization of the subcooled working-fluid (water) in a feedpump and return of the diverted flow to the main plant boiler.

As a guideline for this particular power station, an allowable steam-extraction rate of up to 29.5 kg/s for diversion before the high pressure turbine to Thermal Tank 1 (and also Thermal Tank 2 is considered, which is in series with the first tank; see Fig. 3). This represents 60% of the total steam passing to the high pressure turbine under normal conditions. As a
result, thermal energy can be stored in the Thermal Tank 1 at a maximum heat transfer rate of 60 MWh/h and in Thermal Tank 2 at a rate of 11 MWh/h during the charging of these stores. Assuming 50% depth of discharge, the calculated volumes of Thermal Tanks 1 and 2 are 2000 m³/60 MWh and 375 m³/11 MWh, respectively.

In more detail, superheated steam at 530°C (and 100 bar) is extracted before the high pressure turbine and condensed isobarically in Thermal Condenser Tank 1 to a stream of saturated liquid water at 311°C (100 bar). The storage medium in this tank is a PCM mixture of potassium and sodium nitrates (NaNO₃ + KNO₃) with a melting point of 300°C [18], which is just below the minimum temperature of the steam in the tank. We assume that pure steam enters the pipes of Thermal Tank 1 at a relatively high velocity and that a uniformly-thin condensate film forms around the pipe circumference. Of great importance in the implementation of any such scheme is the space (i.e., volume) required for the installation of the storage tanks that form the core part of this TES system.

Downstream, and in series with Thermal Tank 1, heat transfer also occurs to Thermal Tank 2 where the condensed, high-pressure (initially saturated) water-stream cools further, again isobarically as it charges this second tank. The inlet temperature of this tank is 311°C (at 100 bar) and the outlet temperature is 238°C (at 100 bar). This tank employs the same salt mixture as Thermal Tank 1 with a melting point of 222°C, which is (as in Thermal Tank 1) just below the minimum temperature in this tank.

Finally, after the two TES tanks, the subcooled liquid (water) is compressed in a feedpump and returned to the boiler. The electrical power consumption of the additional feedpump is estimated at 0.09 MW, by assuming an isentropic efficiency value of 80% for this component. The partial diversion of the steam flow to the high pressure turbine during the charging of the two cascaded thermal tanks, leads to a drop in the thermal input of the power station (from 123 MWth; see Fig. 1) to 52 MWth, as the electrical power output of the power plant is derated by 74% (from 50 MWe) to 13 MWe and the corresponding thermal efficiency of the plant reduces (from 39.2%) to 10.6%.

Generally, the overall exergy efficiency associated with the charging and discharging of TES tanks is lower when exploiting latent-heat (PCM) storage compared to sensible-heat storage and the heat-source temperature is variable (e.g., when storing the sensible enthalpy of a hot fluid stream in the absence of phase change) [19], [20]. However, the generation-integrated energy storage solutions examined in this work feature a heat-source (condensing steam from the main Rankine cycle) temperature that is, to a large extent, constant during the storage-tank charging phase, and furthermore, the stored thermal energy is later used, during discharge, to drive (as an example) a secondary power-plant (e.g., an ORC) by evaporating the organic working-fluid, again at constant temperature. This makes latent (PCM-based) TES an interesting alternative with trade-offs necessary for achieving the maximum (“round-trip”) efficiency of the overall system. Furthermore, beyond efficiency considerations, it can be argued that affordability is an even more desirable performance indicator, e.g., with larger temperature differences between the heat source and the material in the thermal store (up to a point) leading to smaller heat transfer areas (i.e., sizes) and costs, even though the thermodynamic performance is lower.

Assuming a negligible temperature difference between the heat source and the PCM in a TES tank, the maximum useful stored power \( W \) during the charging of this tank is the rate change of exergy of the heat-source stream, which can be isothermal or experience temperature variations:

\[
W = \Delta \dot{H} - T_a \Delta \dot{S} = \begin{cases} 
\dot{Q} - \dot{m}_a T_a \Delta s & \text{for isothermal source} \\
\dot{Q} - \dot{m}_a c_p T_a \ln \left( \frac{T_{in}}{T_{out}} \right) & \text{for temperature-varying source}
\end{cases}
\]

(1)

where \( \dot{H} \) and \( \dot{S} \) are the enthalpy and entropy of both the heat-source stream and PCM in the tank, \( \dot{m}_a \) and \( c_p \) are the heat-source stream mass flow-rate and specific heat capacity, \( T_{in} \) and \( T_{out} \) are the inlet and exit temperatures of the stream to/from the tank when its temperature is varying, and \( T_0 = T_a \) is the dead-state temperature that is taken here to be the ambient temperature (\( T_a = 25°C \)).

During the discharging of a TES tank, the stored exergy is converted to electrical power in secondary power plants. Reversible (Carnot) predictions are a useful starting point in setting an upper thermodynamic limit to the performance (i.e., power, efficiency) attainable by these plants. However, these predictions are significant overestimates of the practical performance of real systems [8]. Instead, an endoreversible analysis considers a heat-engine cycle and all of its components as internally reversible except for the heat exchangers (i.e., the heat addition and rejection processes) which are both irreversible, and thus allowed to give rise to exergy losses. This analysis leads to the ‘Novikov’ thermal efficiency expression, which is known to provide much better predictions of the performance of actual power systems [8]. Similarly to the Carnot engine, the Novikov engine is based on a constant source/storage tank temperature, \( T_{in} = T_{st} \), and a constant sink/ambient temperature, \( T_c = T_a \). The Carnot and Novikov efficiency expressions are presented in Equations (2) and (3):

\[
\eta_C = 1 - \frac{T_a}{T_{st}} \\
\eta_N = 1 - \sqrt{\frac{T_a}{T_{st}}}
\]

(2a)

In particular, the Carnot efficiency of the secondary power plant coupled with the 1st TES tank and operating between a temperature of 300°C and the ambient (25°C) is given by:

\[
\eta_C = 1 - \frac{T_a}{T_{st}} = 48\%
\]

(2b)

while that of the secondary power plant coupled with the 2nd TES tank and operating between a temperature of 222°C and the ambient (25°C), is given by:

\[
\eta_C = 1 - \frac{T_a}{T_{st}} = 40\%
\]
Similarly, the Novikov efficiency of the secondary power plant coupled with the 1st thermal tank and operating between 300°C and the ambient at 25°C, is given by:

$$\eta_N = 1 - \sqrt{\frac{T_a}{T_{st}}} = 28\% \quad (3a)$$

while the Novikov efficiency of the secondary power plant coupled with the 2nd thermal tank and operating between 222°C and the ambient temperature of 25°C, is given by:

$$\eta_N = 1 - \sqrt{\frac{T_a}{T_{st}}} = 22\% \quad (3b)$$

In both cases (Carnot and Novikov), a measure of thermal efficiency can be used to obtain the generated electrical power, \(\dot{W}_{\text{cycle}}\) or \(P_{\text{out}}\), from an engine given a thermal-energy input rate, \(\dot{Q}_{\text{in}}\), via Eq. (4):

$$\eta_{th} = \frac{\dot{W}_{\text{cycle}}}{\dot{Q}_{\text{in}}} \Rightarrow \dot{W}_{\text{cycle}} = \eta_{th} \cdot \dot{Q}_{\text{in}} \quad (4)$$

where \(\eta_{th}\) can be either \(\eta_{C}\) or \(\eta_{N}\), and the sink for the secondary power plants is the environment. Therefore, the Carnot (reversible) electrical power of the secondary power plant coupled to the 1st thermal tank is 29 MWe and that of the secondary power plant coupled to the 2nd thermal tank is 4 MWe. Similarly, we can estimate the Novikov (end or reversible) electrical power of the secondary power plants coupled with the 1st and 2nd thermal tanks.

After charging these tanks, secondary power-generation systems undergo power cycles while operating between the (constant) temperature of the PCM in the thermal storage tanks, \(T_{st}\), and the temperature of the ambient environment, \(T_a\).

The theoretical best performance attained in the scheme shown in Fig. 3 is summarized in Table I, including the thermal-energy inputs, secondary heat-to-power conversion efficiencies and associated electrical-power outputs.

<table>
<thead>
<tr>
<th>Descriptions</th>
<th>Thermal Tank 1</th>
<th>Thermal Tank 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Heat rate input (MWth)</td>
<td>60</td>
<td>11</td>
</tr>
<tr>
<td>Reversible (Carnot) efficiency (%)</td>
<td>48</td>
<td>40</td>
</tr>
<tr>
<td>Reversible electrical power (MW)</td>
<td>29</td>
<td>4</td>
</tr>
<tr>
<td>Endoreversible (Novikov) efficiency (%)</td>
<td>28</td>
<td>22</td>
</tr>
<tr>
<td>Endoreversible electrical power (P_{\text{out}}) (MW)</td>
<td>17</td>
<td>3</td>
</tr>
</tbody>
</table>

**IV. RESULTS FOR THE OIL FIRED POWER STATION CASE STUDY**

Figure 4 shows the fractional plant derating during TES charging versus the degree of steam extraction when steam is extracted before the high pressure turbine to the oil-fired power station case study. The fractional derating value is the ratio of the net generator output from the base plant with steam extraction to that without steam extraction, i.e., with a maximum net generator output of 50 MW from the base power plant. From left to right the scheme includes steam extraction up 58% (for details see section III). Fig. 4 shows that the derating of power output is proportional with the steam extraction up to 58% which is the new minimum stable generation of the power station.

As a result of this steam extraction strategy, the electrical power output of the power station reduces and the amount of stored thermal energy increases (from left to right in Fig. 5). This figure suggests that it is possible to use existing oil-fired power plants for flexible power generation in load following with a maximum derating of 74%, with minimum loads down to 26% of the plant’s rating. The stored thermal energy increases with the amount of steam extraction up to a total of 71 MW, as the net power output reduces by 74%, from 50 MW to a minimum stable generation of 13 MW.
when steam is not extracted, while it reduces with the amount of steam extraction. As a result of the steam extraction, the thermal efficiency of this particular oil-fired plant reduces from 39.2% (for full-load plant operation) to 10.6% (for 26% part-load operation).

![Graph](image_url)

**Fig. 6.** Heat input (rate) of main/base oil-fired power station during TES charge, corresponding to the same EMS schemes as in Fig. 4.

At the same time, it is noted that the heat rejection rate at the condenser reduces from 72 MW (see Fig. 1), when the oil-fired power plant operates at maximum power output, to 38 MW (see Fig. 3) when steam is extracted before the high pressure turbine. In effect, this reduced condensation (and waste-heat rejection to the environment) compensates the increased thermal energy that is sent to the secondary power units, which are relatively efficient in converting this to electrical power. This allows a secondary power generation during the discharging of all Thermal Tanks of 20 MW (endoreversible) for a drop in base generation during charging of 13 MW (see Table I), corresponding to effective round-trip efficiencies of around 56%. When performing these calculations based on fully-reversible secondary units (29 MW of electrical power from Thermal Tank 1 and 33 MW from all tanks) round-trip efficiencies in excess of 100% are obtained. Since the maximum available electrical power from the power station is directly correlated to its flexible operation, this suggests that a trade-off exists needed between the overall conversion efficiency of heat to electricity and the station’s load following capability.

**V. OPTIMAL SCHEDULING OF TES IN THE POWER SYSTEM OF CRETE**

In this section the optimal scheduling of the TES, i.e. optimal charging/discharging during the day, is examined in the power system of Crete.

**A. Power System of Crete**

Crete is the largest Greek island and the 5th largest in the Mediterranean Sea with an annual peak load around 700 MW (for 2018). RES are a vital part of Crete’s power system with around 200 MW of wind power and 100 MW of PV plants installed [21]. Figure 8 illustrates the generation and transmission system of Crete.

Three thermal power stations comprising a large number of oil-fired generating units (diesel, gas turbines, steam turbines and one combined cycle unit) with around 708 MW total net capacity are installed in the power system. Compliance to environmental directives 2010/75/EU (IED) [3] and 2015/2193/EU (MCPD) [4] require the decommissioning of a number of local units leading to generating capacity shortage. An AC interconnection with the mainland system with a net transfer capacity of around 180 MW is planned to be completed in the next few years in order to reduce the high operating cost, increase RES penetration levels and improve reliability and generation adequacy of the system. The integration of the TES
in the power system of Crete could have various potential benefits in the following areas:

- **Energy Arbitrage.** The marginal cost of peak load units is substantially higher compared to the cost of base load units in the power system of Crete. Moreover, the interconnection can provide energy at prices even lower compared to the local base units. The TES can exploit this difference of energy prices by storing energy at base load and producing during peak hours.

- **Ancillary Services.** A certain level of spinning reserve is required for the operation of the power system, even after the installation of the interconnection. The TES can substitute expensive local units in the provision of spinning reserve requirements, reducing thus operating costs.

- **Avoidance of Renewable Curtailment.** In the autonomous operation of the power system, the level of RES penetration is limited by the Minimum Stable Generation level of units and the dynamic security constraints. The TES can contribute to store the excessive RES generation.

- **Unit Flexibility.** It is assumed that the interconnected operation of the power system of Crete would require a minimum number of must run local units for steady state stability reasons. This requirement increases operating costs since certain power units are forced to produce energy even at periods, when it could be supplied at lower cost via the interconnection. The power unit of Atherinolakkos will serve as a must run unit and the reduction of its technical minimum which is induced due to the installation of the TES is a desirable effect. The TES can also help to avoid shutting down base load thermal units during low load, as well as the frequent shutting down and startup of power units, thus leading to lower startup costs.

- **Generating Capacity.** The installation of a TES increases the total generating capacity of the system and contributes to the avoidance of installation of new generating units. The value of capacity is evaluated in this study as the difference of the cost of Energy Not Supplied (ENS), as defined in Equation (5) which is minimized subject to the constraints of the TES operation according to Equations (6)–(17):

\[
\min \sum_{i=1}^{24} \sum_{t=1}^{N_{\text{GEN}}} \left( C_i (P_i^t) + SUC_i + P_{\text{inter}}^t \cdot SMP^t + P_{\text{cur}}^t \cdot VOLL \right)
\]

subject to:

**Power Balance Constraint**

\[
\sum_{i=1}^{N_{\text{GEN}}} P_i^t + P_{\text{inter}}^t + P_{\text{RES}}^t + P_{\text{out}}^t + P_{\text{el}}^t = P_{\text{Load}}^t - P_{\text{cur}}^t
\]

**Storage Balance Constraint**

\[
Q_{\text{out}}^t = Q_{\text{stor}}^t - Q_{\text{stor}}^t + Q_{\text{cond}}^t
\]

**Storage output technical Max**

\[
P_{\text{out}}^t \leq \left( 1 - y(t) \right) \cdot P_{\text{max}}^t
\]

**Storage available Max**

\[
P_{\text{out}}^t \leq P_{\text{avail}}^t \quad \text{where} \quad P_{\text{avail}}^t = Q_{\text{stor}}^t / a_{\text{cond}}.
\]

**Storage Capacity Limit**

\[
Q_{\text{stor}}^t \leq Q_{\text{max}}^t
\]

**Boiler balance**

\[
Q_{\text{boil}}^t = Q_{\text{el}}^t + Q_{\text{cond}}^t
\]

**Boiler Min/Max**

\[
x(t) \cdot Q_{\text{boil}}^t \leq Q_{\text{boil}}^t \leq x(t) \cdot Q_{\text{max}}^t
\]

**Turbine Min/Max**

\[
x(t) \cdot Q_{\text{el}}^t \leq Q_{\text{el}}^t \leq x(t) \cdot Q_{\text{el}}^t
\]

**Condenser Min/Max**

\[
y(t) \cdot Q_{\text{cond}}^t \leq Q_{\text{cond}}^t \leq y(t) \cdot Q_{\text{max}}^t
\]

**Main Turbine Min/max**

\[
P_{\text{el}}^t = a_{\text{gen}} \cdot Q_{\text{el}}^t
\]

**Storage output Max**

\[
P_{\text{out}}^t = a_{\text{cond}} \cdot Q_{\text{out}}^t
\]

**Storage reserve availability**

\[
P_{\text{StorSR}}^t \leq P_{\text{max}}^t \quad \text{and} \quad P_{\text{StorSR}}^t + P_{\text{out}}^t \leq Q_{\text{stor}}^t / a_{\text{cond}}
\]

In addition, all other constraints of Unit Commitment – Economic Dispatch are applied such as Technical Minimum and Maximum, primary reserve constraints, ramp rates and Minimum up and down time.

The analysis takes into account the maintenance schedule of generation system as well as stochastic outages according to the Expected Forced Outage Rates (EFOR) of the power units.
A number of cases are investigated, characterized by differences in the operation of the interconnection to the mainland power system (interconnected and autonomous operation), the fuel prices (low, baseline and high price scenarios), the load demand (low and high load assumptions) and the storage capacity (1, 2 and 3 hours capacity).

B. Results

Figure 9 illustrates the aggregate electrical output of the steam unit together with the attached TES system for a random day for the scenario of interconnected operation with low fuel prices and baseline load demand and Figure 10 shows the average annual aggregate electrical output of the steam unit together with the attached TES system. According to these figures, the integration of the storage leads to a more flexible operation of the power unit, which stores energy during valley hours and gives it back to the system at peak demand.

Fig. 9. Daily Operation of the TES system for the scenario of interconnected operation of power system of Crete with low fuel prices and low load for a random day.

The results of the analysis are presented in Table II. A Value of Lost Load (VOLL) of 2,000€/MWh has been assumed to calculate the cost of ENS. Total Cost of each scenario is defined as the sum of fuel cost, startup cost (SUC) and ENS cost. It has been assumed that the installation cost for 1 hour storage is 23.5 M€, for 2 hours is 27 M€ and for 3 hours is 30.5 M€, according to [22], [23]. The equivalent annual cost of the installation is 2.4 M€, 2.75 M€ and 3.105 M€ respectively, considering a discount rate of 8% for a period of 20 years.

The results from Table II indicate that the benefit of the installation of a TES in the power system of Crete lies in the range of 2.7 to 6.0 M€/annum assuming the interconnected operation of the system and from 6.5 to 12.7 M€/annum for the autonomous operation. The benefit increases for high fuel prices and high demand. The largest portion of the benefit can be achieved with a 2 hours storage capacity, in all cases, and in terms of discounted payback period, 2 hours storage is the best option. The investment is less efficient under the assumption of interconnected operation at low fuel prices.

VI. Conclusion

In this paper an energy management system (EMS) for the flexible operation of thermal power stations based on generation-integrated thermal energy storage (TES) has been proposed. The concept is applied on an existing 50-MW oil-fired Rankine-cycle power station. The possibilities of steam extraction before the high-pressure turbine (HPT) of the power station during off-peak demand have been investigated. Steam is extracted from the power station during off-peak demand for the charging of thermal tanks that contain suitable phase-change materials (PCMs). When power is required and/or it is cost-effective the tanks act as heat sources of secondary thermal power, for example as evaporators of, e.g., organic Rankine cycle (ORC) plants that are suitable for power generation at reduced temperatures and smaller scales.

This type of solution offers greater flexibility than TES-only technologies that store thermal energy and then release this back to the base power station, since it allows both derating and over-generation compared to the base power-station rating. Simulations of the operation of the power system of Crete for a large number of scenarios indicate the potential benefits of the installation of TES, especially in the case of high fuel costs, high demand and autonomous operation of the system in which the payback period is 5 years, while they are reduced for interconnected operation, low fuel prices and low demand.

In future work, we intend to investigate additional Energy Management Strategies for the provision of ancillary services in transmission networks of smart grids. We also intend to consider such strategies for increasing the thermal efficiencies of the secondary power stations during peak demand. The design requirements for fast-start plants in relation to the initial capital and operations and maintenance costs for the various levels of fast-start capability is nowadays common practice [24]. We also aim to investigate fast-start secondary power plants with aggressive hot starts (reportedly within 10 minutes, and down to 10 seconds when the plants are at temperature). Such improvements can offer significant benefits to utilities in terms of primary and secondary frequency responses.
TABLE II
RESULTS OF ANNUAL SIMULATION OF THE SCENARIOS UNDER STUDY

<table>
<thead>
<tr>
<th>Load Prices</th>
<th>Fuel Cost (M€)</th>
<th>SUC (M€)</th>
<th>ENS (MWh)</th>
<th>Total Cost (M€)</th>
<th>TES (MWh)</th>
<th>Discounted Payback Period (years)</th>
<th>(Annual Cost) vs Potential Benefit of TES operation (k€)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Low</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Autonomous</td>
<td>173.6</td>
<td>5.4</td>
<td>55</td>
<td>179.1</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>1 Hour      170.9</td>
<td>5.4</td>
<td>2</td>
<td>176.3</td>
<td>7,010</td>
<td>14.7 (2400)</td>
<td>2762</td>
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<tr>
<td></td>
<td>2 Hours      170.0</td>
<td>5.3</td>
<td>3</td>
<td>175.3</td>
<td>11,025</td>
<td>10.9 (2750)</td>
<td>3824</td>
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<td>3 Hours      169.8</td>
<td>5.1</td>
<td>3</td>
<td>174.9</td>
<td>13,612</td>
<td>11.5 (3105)</td>
<td>4157</td>
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<tr>
<td>Interconnected</td>
<td>190.8</td>
<td>6.4</td>
<td>43</td>
<td>197.4</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>1 Hour      188.1</td>
<td>6.2</td>
<td>2</td>
<td>194.3</td>
<td>6,973</td>
<td>12.5 (2400)</td>
<td>3063</td>
</tr>
<tr>
<td></td>
<td>2 Hours      187.3</td>
<td>6.0</td>
<td>3</td>
<td>193.3</td>
<td>11,082</td>
<td>10 (2750)</td>
<td>4042</td>
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<td>5.9</td>
<td>4</td>
<td>192.5</td>
<td>14,035</td>
<td>9 (3105)</td>
<td>4883</td>
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<tr>
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<td>208.2</td>
<td>7.4</td>
<td>41</td>
<td>215.7</td>
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<tr>
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<td>1 Hour      204.5</td>
<td>7.3</td>
<td>4</td>
<td>211.8</td>
<td>7,072</td>
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<td>3669</td>
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<td>6.7</td>
<td>4</td>
<td>210.2</td>
<td>11,043</td>
<td>6.5 (2750)</td>
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<td>6.6</td>
<td>3</td>
<td>209.7</td>
<td>13,813</td>
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<td>47</td>
<td>196.1</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>1 Hour      187.5</td>
<td>5.6</td>
<td>3</td>
<td>193.2</td>
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<td>5.5</td>
<td>46</td>
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<td>12,876</td>
<td>12.2 (2750)</td>
<td>3550</td>
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<td>5.4</td>
<td>47</td>
<td>192.1</td>
<td>15,880</td>
<td>12.3 (3105)</td>
<td>3994</td>
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</table>

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