INVITED PAPER

Molten-Salt Power Towers: Newly Commercial Concentrating Solar Storage

This paper looks at a new type of storage plant which has now reached commercial status, with the 19.9-MWe Torresol Gemasolar power tower, featuring 15 h of molten-salt storage, having come online in Spain in May 2011.

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ABSTRACT | Molten-salt storage is already commercially available for concentrating solar power (CSP) plants, allowing solar power to be produced on demand and to "backup" variable renewable sources such as wind and photovoltaics. The first CSP plants to operate commercially with molten-salt storage utilized parabolic trough concentrators, for example, the Andasol-1 plant. A new type of storage plant has now reached commercial status, with the 19.9-MW_e Torresol Gemasolar power tower, featuring 15 h of molten-salt storage, having come online in Spain in May 2011. Advantages of the power tower storage system include the elimination of heat transfer oil and associated heat exchangers, a lower salt requirement, higher steam cycle efficiency, better compatibility with air cooling, improved winter performance, and simplified piping schemes. Near-term advances in molten-salt power tower technology include planned up-scaling, with SolarReserve due to begin constructing a 110-MW_e plant in Nevada by August 2011. Other advances include improvements to the thermal properties of molten salts and the development of storage solutions in a single tank. With these developments at hand, CSP will continue to provide dispatchable solar power, with the capacity to provide energy storage for 100% renewable electricity grids in sun-belt countries.

KEYWORDS | Central receivers; concentrating solar power (CSP); energy storage; molten salt; power towers

I. INTRODUCTION

Concentrating solar power (CSP) can both generate and store renewable energy all in the one plant, delivering dispatchable power—an enticing combination in the eyes of a grid operator. Parabolic mirrors concentrate the sun's energy to a hot focus. This heat can be used to produce steam for immediate electricity generation, or alternatively it can be stored prior to electricity generation using molten salt [1]–[3], sensible heat storage in solids [4]–[6], phase change salts [7], or thermochemical storage cycles [8]–[10]. When required, this stored energy can be used to produce steam and drive a turbine. In this way, variable renewable energy sources such as wind and photovoltaics can be dispatched to the grid first, and the "backup" provided by concentrating solar plants with storage.

Of the CSP storage methods listed, molten-salt storage is the only storage currently used in commercial CSP plants. Molten-salt CSP storage has been commercially proven since the end of 2008, when the 50 MW_e (MW electric) Andasol-1 trough plant (Fig. 1) began power production with 7.5 h of molten-salt storage, near Guadix in the province of Granada, Spain [11]. As of July 2011, seven similar 50-MW_e parabolic trough plants, each with 7.5 h of molten-salt storage have come online in Spain, bringing the total to eight: *Andasol-1*, *Andasol-2*, *Extresol-1*,

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Fig. 1. ***An aerial view of the Andasol-1 and Andasol-2 plants (Photo: Cobra Energía). Left inset: Parabolic troughs tracking the sun at Andasol-1 (Photo: Author). Right inset: The hot and cold salt tanks and power block during construction of Andasol-1 (Photo: Cobra Energía).***

Extresol-2, *Manchasol-1*, *Manchasol-2*, *La Florida*, and *La Dehesa* [12]. Andasol-2 is located adjacent to Andasol-1 (see Fig. 1), while Manchasol-1 and Manchasol-2 are located in the province of Ciudad Real, and the latter four plants are all located in the province of Badajoz. Another 17 trough plants with molten-salt storage are in advanced stages of construction in Spain [12], and more are planned. But there is a new technology entering the CSP storage market, and it comes with some advanced features.

At the beginning of May 2011, the 19.9-MW_e Torresol Gemasolar power tower shown in Fig. 2 began selling power into the grid near Fuentes de Andalucía in the province of Seville, Spain. Test runs of the Gemasolar power tower had been carried out since March 2011. Gemasolar thus became the first commercial power tower to operate with dispatchable storage.[1] The developer and operator, Torresol Energy based in Vizcaya, Spain, is a joint venture between the Spanish engineering firm SENER (60%), also headquartered in Vizcaya, and Abu Dhabi-based Masdar (40%) from the United Arab Emirates. Plant construction has been carried out by a joint venture between SENER and Madrid-based Cobra Energía.

Gemasolar has a gross turbine capacity of 19.9 MW_e, and a net capacity of 17 MW_e during daylight hours. This net capacity can increase above the 17 MW_e overnight when there are lower parasitic loads, as at night it is not necessary to pump salt up the tower to the receiver, and there is no mirror field operation. Like the trough plants discussed above, Gemasolar uses molten salt to store energy, but in this case, enough storage is provisioned for 15 h of operation after dark at the full 19.9-MW_e gross capacity. This will allow Gemasolar to operate at an annual capacity factor of 74% from solar alone [14]. Given a net plant capacity of 17 MW_e, an annual capacity factor of 74% means that Gemasolar will produce 110 000-MWh/y net, out of a possible total of 148 920 MWh/y if it operated at 17-MW_e net output, 24 h a day, 365 days a year. In contrast, the aforementioned trough plants with storage have a capacity factor of around 41% [1]. From a technical point of view, the capacity factor of a trough plant could be increased by increasing the size of the mirror field and storage compared to the turbine. However, as discussed in this paper, with current trough technology this is a less attractive option economically than constructing a power tower with high capacity factor.

This review presents a history of molten-salt power tower development, the unique features of this technology, the case-study of the Gemasolar plant, and the near-term advances that can be expected in this field.

II. HISTORY OF MOLTEN-SALT POWER TOWERS

The first power towers to directly heat molten salt were the 2.5-MW_e THEMIS tower in the French Pyrénées, and the 1-MW_e Molten-Salt Electric Experiment (MSEE/Cat B)

[1] Abengoa Solar's PS10 and PS20 power towers have limited saturated water thermal storage. In the case of PS10, this is 20 MWh_t or enough to run the turbine at 50% load for 50 min [13]—this is designed to ride through cloud transients, rather than to produce dispatchable power.

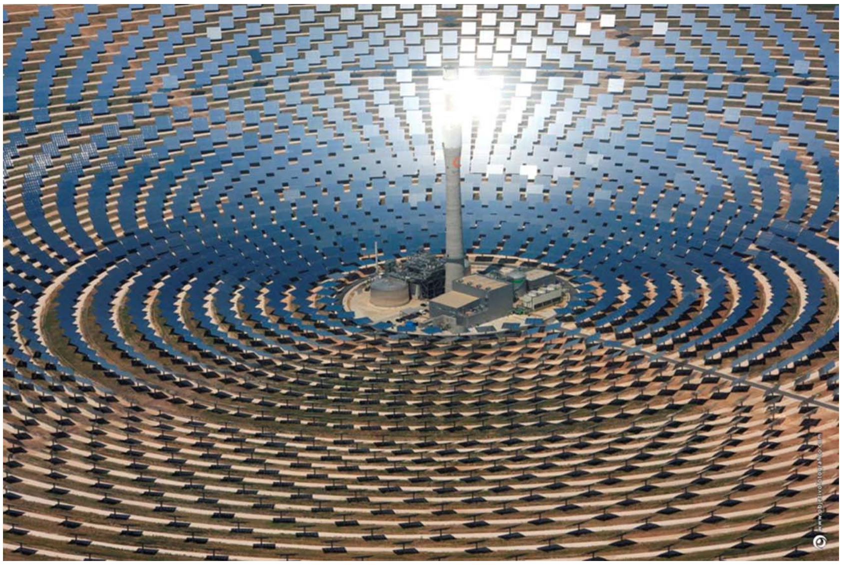

Fig. 2. *The 19.9-MW$_e$ Gemasolar power tower with 15 h of molten-salt storage. (Photo: Torresol Energy, 2011.)*

Project in the United States, both of which began operation in 1984 [15], [16]. These were followed by the 10-MW$_e$ Solar Two power tower near Barstow, CA, which featured 3 h of molten-salt storage, and operated from 1996 to 1999 (see Fig. 3) [3], [15]. The cost of the Solar Two project was shared between the U.S. Department of Energy, and various industry partners, with technical support from Sandia National Laboratories and the National Renewable Energy Laboratory (NREL). A full list of project participants is given by Pacheco *et al.* [3]. The Solar Two project retrofitted molten salt, both as heat transfer fluid and storage technology, to the existing Solar One power tower concentrator. Solar One operated with a steam receiver, and oil/rock storage from 1982 to 1988. Solar Two, on the other hand, demonstrated molten-salt power tower technology at a large scale, and resulted in practical recommendations for the commercialization of the technology.

Due to a lack of policy incentives, no molten-salt power towers were constructed from 1999 until November 2008, when construction began on the Torresol Gemasolar power tower. Originally conceived as the *Solar Tres* project [16], [17]—Spanish for "Solar Three"—the Gemasolar tower builds on the experiences gained during the operation of the Solar One and Solar Two research facilities in the United States, with project-specific engineering completed by SENER.

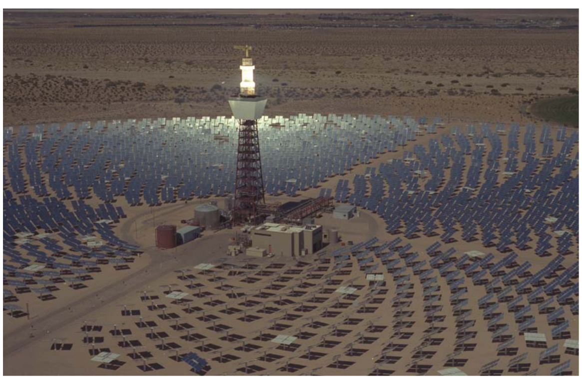

Fig. 3. *The 10-MW$_e$ Solar Two power tower near Barstow, CA, which featured 3 h of molten-salt storage, and operated from 1996 to 1999. The receiver can be seen glowing white, indicating that the plant is operating in solar collection mode (daytime). (Photo: Sandia National Laboratories.)*

III. THE PRINCIPLE OF MOLTEN-SALT STORAGE

One of the most important characteristics of using a thermal storage system is the very high efficiency of the storage, with an annual efficiency of 99% possible for commercial plants [3]. The only losses come from:

- slow heat loss through the tank walls, which is kept to a minimum via insulation;
- the heat exchange process between mediums, i.e., salt to steam for towers, or oil to salt, salt to oil, and then to steam, in the case of a trough system.

When this steam is converted to electricity, the typical net steam (Rankine) cycle efficiency for a superheat plus reheat system at 540 °C and 100 bar is 38%. As with any thermal power generation (including coal and gas), the conversion from heat to electricity gives the largest energy loss in the system. However, in a thermal storage system, the energy is stored as heat prior to conversion to

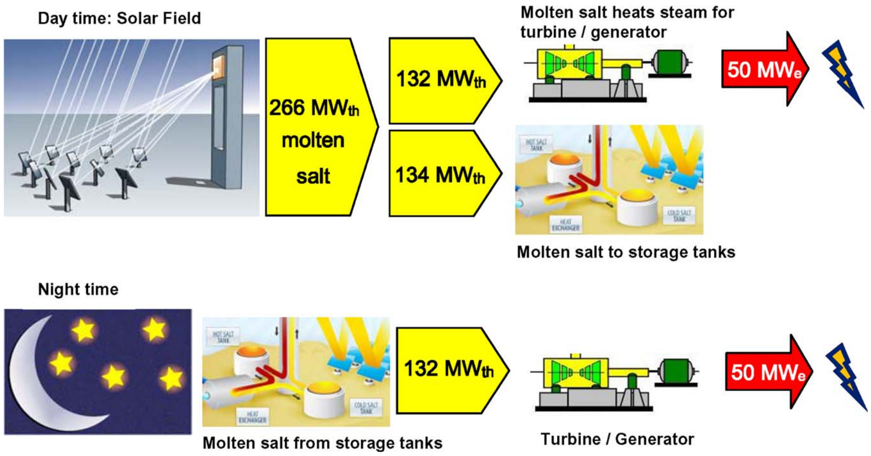

Fig. 4. ***Daytime and nighttime operation of a solar power tower with storage.***

electricity through the Rankine cycle—thus these conversion losses do not affect the efficiency of the storage.

For example, consider a concentrating solar tower which has a net 50-MW_e (MW electric) turbine, but has the solar mirror array oversized by a factor of two, so that half the solar energy being collected at any time can be sent to storage (Fig. 4). With the oversize in the system, the solar receiver will collect 266 MW_t (MW thermal) of solar energy in the molten salt at peak incident solar radiation. Of this, 132 MW_t of thermal power directly feeds the Rankine cycle for "on-sun" power generation, producing 50 MW_e of electricity, while 134 MW_t of thermal power is stored in the hot tank. During the night, the molten salt from the storage tanks provides 132 MW_t of steam to the turbine (with 2 MW_t lost during the storage process) and 50 MW_e of electricity is produced.

Because the energy generation system is completely independent of the energy collection system, a steady flow of power can be produced regardless of whether the sun is shining at full strength, or partial strength, or whether it is cloudy, or nighttime—as long as there is sufficient energy stored in the hot salt tank. The mirror fields are oversized to allow the storage tanks to be filled during the day while electric power is generated simultaneously. The exact balance of mirror field size, to turbine size, to storage size can be optimized depending on the desired performance of the CSP plant. For example, a plant with upwards of 15 h of storage can act as a "baseload" power plant, while a plant with 6–8 h of storage but a larger turbine can meet the afternoon–evening peak power demand.

Clearly, even a plant with 17 h of storage cannot operate for more than a day during an extended cloudy period. However, Wright and Hearps [18] have shown that using a geographically diverse grid, a country such as Australia could be powered with 59% of such molten-salt power tower plants, 39% wind energy, and only 2% annual backup from hydroelectricity and biomass.

IV. MOLTEN-SALT PROPERTIES

Currently, both trough and tower plants use the same molten-salt mix for storage—a 60 wt% to 40 wt% mix of sodium and potassium nitrate know as Solar Salt, illustrated in Fig. 5. At room temperature, Solar Salt is a white crystalline solid. Therefore, during plant commissioning, it is necessary to melt the entire salt inventory. The salt inventory then remains in the liquid state for the operating life of the plant.

Solar Salt is a eutectic mixture, meaning that this particular composition melts at a lower temperature than any other ratio of the two salts, and that at this ratio, both of the salts begin melting at the same temperature. Solar Salt was chosen for use with molten-salt power towers because its upper stability temperature limit (600 °C) allows high-efficiency Rankine cycle turbines to be used [19], for example, a superheat plus reheat system, or potentially a supercritical plus reheat system.

Fig. 5. ***Potassium and sodium nitrate prior to the melting process. In the liquid state, it is clear with a yellow tinge, like beer.***

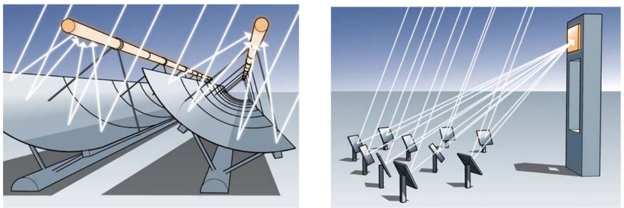

Fig. 6. *Operating principles of (a) parabolic troughs and (b) power towers. (Images: copyright Siemens.)*

Solar Salt has a relatively high freezing point of 220 °C, which is manageable for a heat transfer fluid in a power tower solar plant, but would be more challenging as the heat transfer fluid in a trough solar field. It is important to avoid freezing of the molten salt within tubing: first because this can cause a blockage which prevents flow of molten salt; second because the frozen slug or section must be carefully thawed; and third as even a small number of freeze/thaw cycles can result in tube rupture.

For example, at the Solar Two facility, frozen plugs of salt were sometimes encountered in the receiver tubing during startup in windy conditions [3]. This prevented a flow of molten salt within that section of receiver tubing, and if left unchecked, the tube could plastically yield and fail under concentrated solar flux. In addition, laboratory tests confirmed that 12 freeze/thaw cycles of the receiver tubes would cause tube rupture [20]. Several methods were employed to address this problem. A special preheat method was developed for aiming heliostats onto the receiver tubes during startup to avoid freezing of the salt within the receiver tubes, and at the same time avoid overheating the tubes while the filling process occurred. Oven covers on the receiver tube manifolds were modified to improve their exterior seals and baffles installed to prevent air flow from one oven cover to the next. In addition, adequate electric heat tracing—resistive insulated heating—was recommended for the interface between the receiver tube absorber surface and the oven cover during startup, as this location was difficult to aim at with the heliostats. Such heat tracing was used in other piping and valves in the plant during startup to prevent freezing and thermal shock.

Freezing of the salt was also encountered in the evaporator at the Solar Two facility [3]—the heat exchanger between the salt and water, in which saturated steam was produced. This freezing was due to cold water being passed through the evaporator during startup, and as few as four freeze/thaw cycles could cause tube rupture. To address this issue, a feedwater heater was installed for use during startup, and the feedwater flow path was altered.

Such freeze events must be avoided with the use of molten salt as a heat transfer fluid in power towers. Moreover, it should be noted that the potential for freeze events in a parabolic trough plant using molten salt as a heat transfer fluid would be much higher, due to the much larger receiver area, and lower concentration ratio, as shown in Section V and Fig. 6.

Table 1 lists the compositions and properties of a variety of salt mixtures used as heat transfer fluids. In addition to Solar Salt, both Hitec and HitecXL are commercially available. Hitec and HitecXL have lower melting points than Solar Salt—142 °C and 120 °C, respectively—but are restricted to lower maximum temperatures. In addition, Hitec, containing a nitrite salt, requires an N_2 cover at atmospheric pressure in the thermal storage tanks to prevent conversion to nitrate [19].

In practice, the upper operating temperature of the salt is not only limited by its own thermal degradation, but also by the properties of the metal piping in which it is contained. For example, an upper operating temperature of 565 °C was

Table 1 Compositions and Properties of a Variety of Salt Heat Transfer Fluids (HTFs)

Heat transfer salt	*Melting point (°C)*	*Thermal stability limit (°C)*	*Density at 300°C (kg/m^3)*	*Viscosity at 300°C (Pa.s)*	*Heat capacity at 300°C (J/(kg.K))*	*Thermal conductivity (W/(m.K))*
Solar Salt (60:40 Na:K nitrate)	220	600	1899	0.00326	1495	0.55 (at 400°C)
Hitec (7:53 Na:K nitrate, 40 Na nitrite)	142	535	1640	0.00316	1560	
HitecXL (7:45:48 Na:K:Ca nitrate)	120	500	1992	0.00637	1447	
Sandia mix QA (18:56:8:18 Na:K:Li:Ca nitrate)	< 95	500	2018 (at 150°C)	0.005 – 0.007	1440 (at 247°C)	0.522 (at 250°C)
Sandia mix QB (13:66:7:14 Na:K:Li:Ca nitrate)	< 90	500	2015 (at 150°C)	0.005 – 0.007	1160 (at 247°C)	0.654 (at 250°C)
Halotechnics HTF (6:23:8:19:44 Na:K:Li:Ca:Cs nitrate)	65	561				

Properties for Solar Salt, Hitec and HitecXL from [19],except thermal conductivity [26]. Properties for Sandia mixes from [26] and for Halotechnics HTF from [27]. Compositions are listed in weight percent.

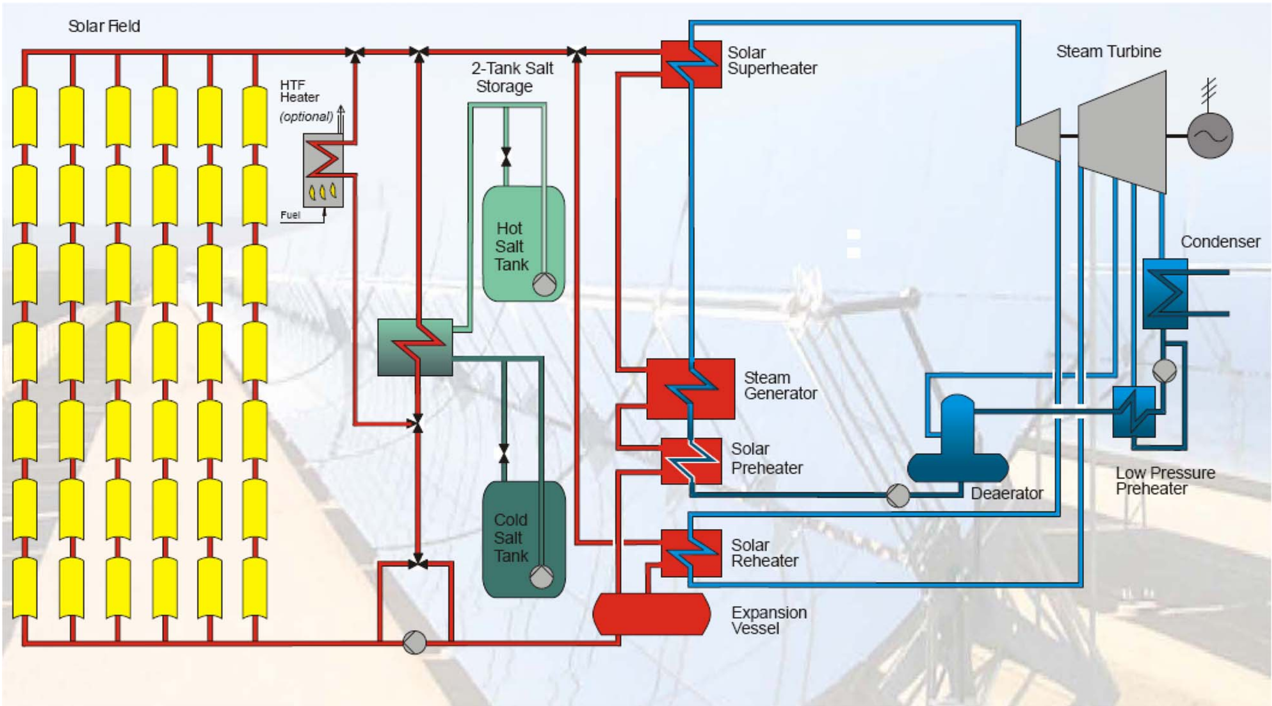

Fig. 7. ***A plant flow diagram for Andasol-1 and similar plants. The parabolic trough solar field heats oil up to 393 °C. This can either be fed directly to the oil-to-steam heat exchanger to produce power immediately, or to the oil-to-salt heat exchanger for storage. Power can then be produced on demand.***

used at Solar Two, and will be used at Gemasolar as stainless steel is corrosion resistant to Solar Salt at this temperature. Stainless steel types 316 and 304 were used for the receiver and hot salt pipework at Solar Two [3]; although type 347 is recommended as in addition to withstanding Solar Salt corrosion at 565 °C, it is not susceptible to aqueous cracking. On the other hand, carbon steel is sufficient for "cold" salt pipework, as Solar Salt is less corrosive at 292 °C.

V. A COMPARISON OF TROUGH AND TOWER STORAGE PLANTS

Trough and tower concentrators differ in the method of transferring heat to the molten salt. Fig. 6 compares the optical operation of parabolic trough concentrators and power towers, or "central receiver" concentrators. Parabolic troughs have a linear focus and low concentration ratio (less than 100), while power towers have a point focus and high concentration ratio (greater than 1000)—the geometric concentration ratio being the ratio of the area of the receiver aperture to the area of mirror aperture. These factors influence the heat transfer to the salt, as described below.

A. Trough Plants With Storage

Commercial trough plants with storage, such as Andasol-1, use parabolic trough mirrors to heat oil up to 393 °C (the thermal limit of the oil) with concentrated solar power, as illustrated in Figs. 1, 6(a), and 7. Some of this oil is fed directly to the oil-to-steam heat exchanger to produce power straight away. The rest of the oil is passed through an oil-to-salt heat exchanger to heat molten salt for storage in an insulated tank at 386 °C. Power can then be produced on demand—the molten salt heats the oil, which in turn produces superheated steam to feed the turbine/generator set at 100 bar and 377 °C [21]. The cooled salt at 292 °C then returns to the "cold" tank, where it remains until it is reheated the next morning.

B. Tower Plants With Storage

Fig. 8 illustrates the operating principle of a molten-salt power tower, such as Gemasolar, which uses molten salt as both the heat transfer fluid and the storage medium.

1) "Cold" molten salt at 292 °C is pumped to the receiver at the top of the tower, where it is heated by concentrated solar radiation from the field of heliostat mirrors.
2) Hot salt at 565 °C travels back down the tower and is stored in the insulated hot salt tank [3], [22].
3) When power is required, hot salt from the storage tank is passed through the heat exchanger to create superheated steam—at 535 °C and 100 bar in the case of Solar Two [3], but 540 °C for commercial plants—to turn the turbine and generate electricity. The cooled salt then returns to the "cold" tank.

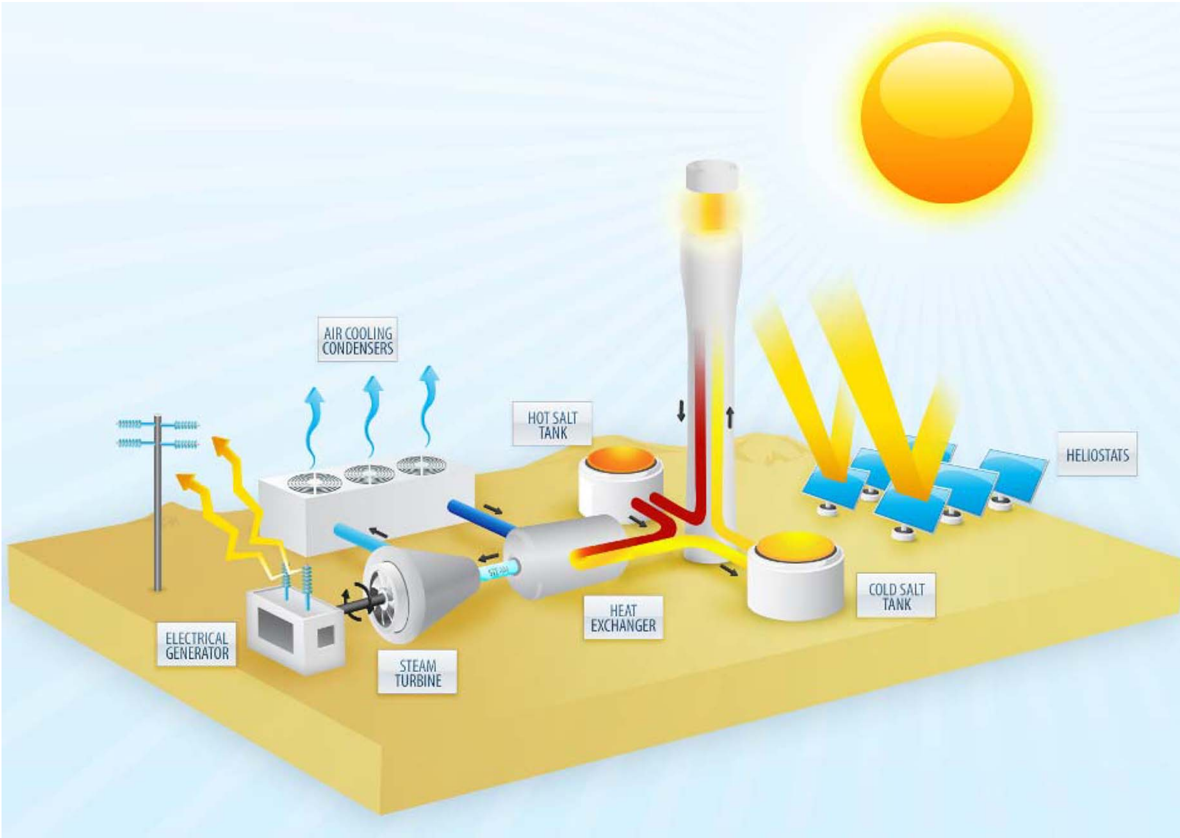

Fig. 8. ***The operating principle of a molten-salt power tower (image: Sharon Wong). "Cold" molten salt at 292 °C is pumped to the receiver where it is heated to 565 °C. This is then stored in the insulated hot salt tank. When power is required, hot salt is passed through the heat exchanger to create superheated steam at 540 °C and 100 bar to feed the turbine and generate electricity.***

Towers can achieve higher temperatures than the current trough technology which is limited both by heat transfer oil degradation and the lower concentration ratio of the trough concentrators. Higher operating temperatures mean that less salt is required to store the same amount of energy, the steam cycle can operate at higher efficiencies, and air cooling can be used with a lower performance penalty, as described below.

- *Salt requirement*: The hot molten salt is stored at 565 °C for power towers, as opposed to 386 °C for troughs. The heat stored is proportional to the difference between hot and cold tank temperatures. In both cases, the cold salt is stored at 292 °C. This gives a temperature difference between hot and cold tanks of 273 °C for towers and 94 °C for troughs. Therefore, a tower plant can store almost three times as much energy in the same amount of salt as a trough plant.
- *Steam cycle efficiency*: The steam (Rankine) cycle efficiency is also related to the maximum steam temperature. Therefore, at 100 bar, the 540 °C steam from the tower plant is much preferred to the 377 °C steam from the trough plant.
- *Air cooling*: Concentrating solar plants are often sited in locations with limited water. This makes air cooling an attractive option for the steam cycle. Air cooling, however, causes a performance penalty on the steam cycle, and again this is linked to the maximum steam temperature. The penalty for towers is around 1.3%, while for troughs it is 4.5%–5% relative to power production with wet cooling [23].

The elimination of heat transfer oil from the plant not only allows higher temperatures to be attained, but it also leads to simplification of the plant design and cost savings. There is no longer a need for both oil-to-steam and oil-to-salt heat exchangers, only salt-to-steam heat exchangers. In addition, purchase of the oil itself is avoided, which is also a significant cost at \$US 57.50/kWh$_t$ [19] (2003), compared to Solar Salt at \$US 5.80/kWh$_t$ [19] (2003). In 2010, the cost of Solar Salt had risen to \$13.80/kWh$_t$ [24]. However, this cost is expected to drop again as new producers from Asia create more competition in the market.

From an optical perspective, the winter performance of power towers remains high, as the heliostat mirrors track the elevation of the sun in the sky, as well as movement

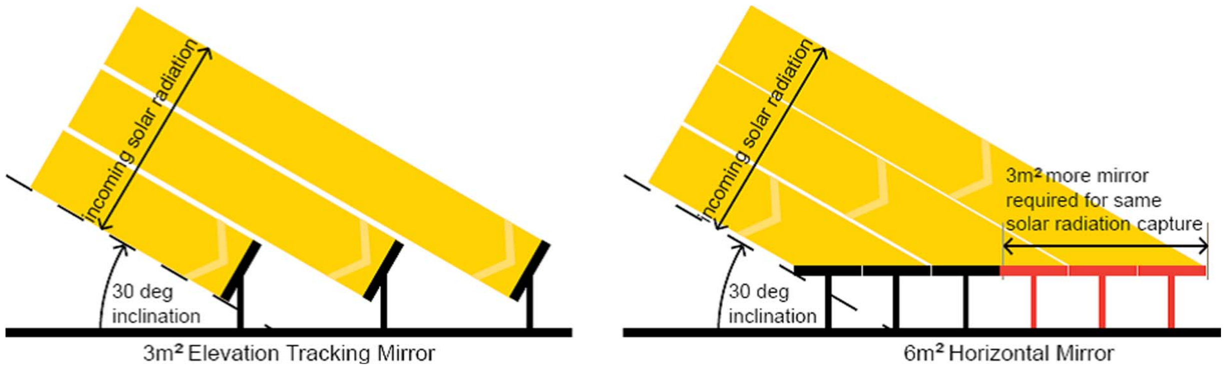

Fig. 9. *Cosine losses for elevation-tracking mirrors and horizontal mirrors at a solar altitude of 30 °C. (Image: Heidi Lee.)*

from east to west. In contrast, troughs and other linear concentrators generally track from east to west, and hence suffer their highest cosine losses in winter, when the sun is at a low angle to the horizon. This effect is illustrated in Fig. 9. This becomes important when considering large penetrations of solar power on the grid, as the most difficult period in which to supply energy is winter.

The optical characteristics of towers also lead to simplified plant design, as the point focus allows a short and simple piping circuit—essentially up and down the tower. This reduces energy losses and material costs for the piping circuit.

VI. GEMASOLAR PLANT CHARACTERISTICS

The Gemasolar plant—the first commercial power tower to operate with molten-salt storage—exhibits the advantages of tower plants with storage as outlined in Section V, although for this particular plant, water cooling has been used. Gemasolar is shown again in Fig. 10, with heliostat focusing and closeups of the molten-salt storage system shown in Fig. 11, and "on-sun" operation of the plant shown in Fig. 12. Some statistics for the plant, which began selling electricity into the Spanish grid in May 2011, are listed in Table 2. The 17-MW_e net turbine output allows for parasitic loads, for example, pumping salt up and down the tower during the day. The plant has benefited from technological advances in the design of heliostats, drive mechanisms, and in-plant control [2].

VII. ADVANCES IN MOLTEN-SALT STORAGE

The application of molten-salt storage to power towers is not the end of the story for molten salt. Here we discuss some near-term advances in the technology.

Fig. 10. *The 19.9-MW_e Gemasolar power tower with 15 h of molten-salt storage. (Photo: Torresol Energy, December 2010.)*

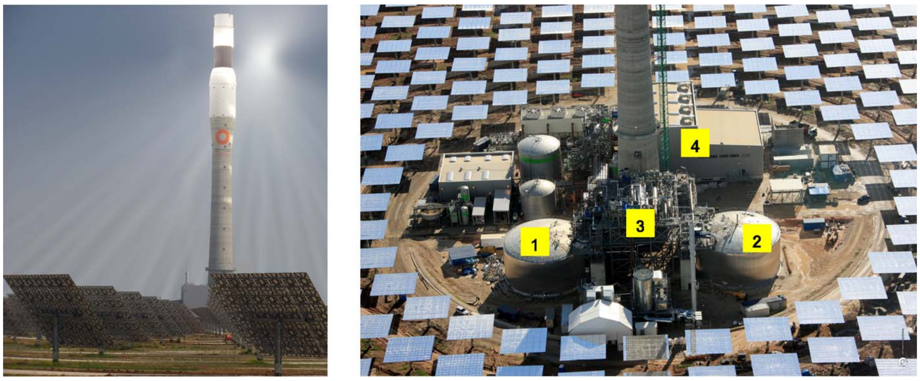

Fig. 11. ***Left: The Gemasolar heliostats in the standby position, ready to aim at the solar receiver. Right: A closeup of the Gemasolar storage plant. Number (1) indicates the hot salt tank, (2) the cold storage tank, (3) the heat exchanger equipment, and (4) the turbine and generator block. The white tent below the heat exchanger was a temporary store for salt during the melting process. (Photos: Torresol Energy, April 2011 and December 2010.)***

A. Up-Scaling Molten-Salt Power Towers

On the other side of the Atlantic, United States-based SolarReserve is also developing molten-salt power towers. SolarReserve's first project is set to be their 110-MW_e Crescent Dunes Solar Energy Project near Tonopah, NV. Crescent Dunes will be provisioned with 8 h of molten-salt storage, and will produce 480 000 MWh of electricity annually. In May 2011, SolarReserve received a U.S. Department of Energy offer for a US$ 737 million loan guarantee, and construction is due to commence by August 2011. In the meantime, the U.S. Department of Energy has also awarded around US$ 10 million each to Abengoa Solar, eSolar, and Pratt & Whitney Rocketdyne—technology providers for SolarReserve—to further develop tower-based storage systems [25]. Developers Solar Millennium have also recently entered the tower-plus-storage market.

B. Advanced Salt Mixtures

As mentioned previously, the salt currently used in molten-salt plants is a 60%–40% mix of sodium and potassium nitrate. To avoid the crystallization point of this salt mix, the molten salt is operated between 292 °C and 600 °C (or 565 °C due to piping material limitations—see Section IV). Various research groups are investigating ternary, quaternary, and even five-component salt mixtures with extended working temperature ranges (see Table 1). As the energy stored in a salt is proportional to the temperature difference, an extended temperature range means that more energy can be stored in the same amount of salt. A lower freezing point also reduces the risk of freeze events. Bradshaw and Siegel [26] investigated salt mixtures including sodium, potassium, calcium, and lithium nitrates, to increase the liquid temperature range of the salts to 100 °C–500 °C (Table 1). More recently, Raade and Padowitz [27] developed

Fig. 12. ***The Gemasolar power tower in solar collection mode (daytime) with the molten-salt heated at the illuminated receiver. The support structures of the heliostat mirrors are also clearly shown. (Photo: Torresol Energy 2011.)***

Table 2 Key Statistics for the Gemasolar Plant (Adapted From [14])

Characteristic	*Quantity*
Number of heliostats	2,650
Total reflective area (m^2)	306,658
Tower height (m)	140
Receiver power (MW_t)	120
Turbine power, gross (MW_e)	19.9
Turbine power, net (MW_e)	17
Storage size (hours of operation without solar radiation)	15
Storage tank dimensions (height x diameter, m)	10.5 x 23
Mass of salt (tons)	8,500
Annual net electricity generation (MWh/year)	110,000
Capacity factor	74 %

a five-component eutectic salt mix with a liquid range from 65 °C to 561 °C. This consisted of lithium nitrate (8 wt%), sodium nitrate (6 wt%), potassium nitrate (23 wt%), cesium nitrate (44 wt%), and calcium nitrate (19 wt%). Ultimately, different quantities of each salt in the mix may be used to achieve a reasonable liquid range at a reasonable cost.

A different approach is being adopted by Glatzmaier *et al.* [28]. They are attempting to add small quantities of metallic nanoparticles to molten salt to increase the heat capacity of the salt. The energy stored in a salt is also proportional to the heat capacity, so if the heat capacity is doubled, twice the heat energy can be stored in the same amount of fluid within the same temperature limits.

C. Thermocline Salt Tanks

Current commercial molten-salt storage systems all use a two-tank system, as illustrated in Figs. 1, 7, 8, and 11. Cold salt at 292 °C is stored in one tank, and once heated by the solar field, the hot salt is stored in a separate tank at 386 °C (trough plant) or 565 °C (tower plant). These salt storage tanks can be quite sizeable, especially at parabolic trough plants. For example, for 7.5 h of storage at the 50-MW_e Andasol-1 plant, both the hot tank and cold tank are sized to accommodate almost the entire inventory of 28 500 tons of molten salt—leading to a tank diameter of 38.5 m and height of 14 m [1]. At the Torresol Gemasolar power tower, 15 h of storage for the 19.9-MW_e plant is provided by 8500 tons of salt. Again, both the hot tank and the cold tank can house almost the entire inventory, each having a diameter of 23 m and a height of 10.5 m, as outlined in Table 2. In either case, the total tank capacity is almost twice the volume of the salt inventory, with the slight difference allowing for tank heels. In a two-tank system, both tanks are never more than half-full at the same time. Therefore, building a single tank that contained both the cold salt and the hot salt at once—a thermocline tank—could produce substantial cost savings. This is not only because just one tank would need to be constructed, of roughly the same size as each tank in the two-tank system, but also due to cost savings in the auxiliary piping and equipment, and in some cases, a reduction in salt inventory.

Both Sandia National Laboratories in the United States and SENER in Spain are developing such tanks, but each is using a different method to maintain a temperature difference between the hot salt at the top of the tank and the cold salt at the bottom.

The thermocline tank under development by Sandia Laboratories uses low-cost filler materials as the primary thermal storage medium, with molten nitrate salts as the heat transfer fluid. Sandia Laboratories has identified suitable filler materials, and tested a 2.3-MWh_t thermocline tank [29]. Out of 17 candidate filler minerals, quartzite rock and silica sand were identified as the preferred mix, withstanding both isothermal and thermal cycling tests (10 000 cycles) in molten nitrate salts at up to 500 °C [29], [30]. In addition, quartzite rock and silica sand are inexpensive, readily available, and have suitable heat capacities. As well as providing the bulk of the thermal capacitance, the filler also prevents convective mixing within the tank. However, it has also been found to promote diffusion within the tank, and hence spread the thermocline region [24]. Nevertheless, modeling has shown that if sliding pressure operation is used, the annual performance of such a thermocline system should be comparable to that of a two-tank storage system [24], [31].

The U.S. Electric Power Research Institute (EPRI) recently conducted a study into both technical and fiscal aspects of thermocline storage systems for power tower and trough plants, based on the Sandia thermocline tank concept [24]. Thermal ratcheting was identified as a potential problem requiring further investigation. This effect involves the filler material compacting at the bottom of the tank over the course of many cycles, and then expanding as it is heated, placing extra pressure on the tank walls. However, investigators are optimistic that this challenge can be overcome, in part because the 180-MWh_t oil-based thermocline tank operated at the Solar One power tower facility was comfortably able to withstand such pressures [31].

On the fiscal side, EPRI has analyzed both thermocline and two-tank storage systems for molten nitrate salts with both power tower and trough solar fields, for a range of storage capacities—from 100 to 3500 MWh_t. At each design capacity, the thermocline system provided a lower installed storage capital cost than the two-tank system. The main cost difference was due to the reduced salt inventory—the thermocline systems studied require roughly half the salt inventory of a two-tank system. Similarly, at each design capacity, the direct power tower system—i.e., directly heating molten salt as the heat transfer fluid—gave a lower installed storage capital cost than indirect trough systems which heat oil in the solar field. The main difference in this case was the absence of the oil-to-molten-salt heat exchanger. For a 3500-MWh_t storage system, EPRI predicted costs of:

- \$34/kWh_t for direct power towers with thermocline storage;
- \$50/kWh_t for direct power towers with two-tank storage;
- \$73/kWh_t for indirect trough plants with thermocline storage;
- \$89/kWh_t for indirect trough plants with two-tank storage.

SENER's thermocline tank concept on the other hand does not involve filler material. Instead, SENER is proposing a single tank with a floating barrier to separate the hot and cold salt [32].

D. Other Molten-Salt Projects

It should also be noted that aside from power towers, molten salt is also being applied to other novel systems. The

5-MW$_e$ Archimede project in Sicily is aiming to prove that molten salt can be heated directly by troughs [33]. If successful, this will eliminate the need for heat transfer oil, and bypass the 393 °C temperature limit imposed by the oil, allowing the salt to attain higher temperatures with trough concentrators. The Archimedes project leaders have chosen to use Solar Salt as the heat transfer fluid to attain temperatures up to 550 °C, even though this comes with a relatively high freezing point of 220 °C. To reduce the risk of freeze events, extensive heat tracing has been installed in the solar field. In addition, a new receiver selective surface was developed for this project, as previous selective surfaces for trough receivers have not been stable to such high temperatures [34]. This selective surface allows the receiver to absorb 95% of the incident solar radiation, but only re-emit (lose) 10% of that energy via infrared radiation.

In the meantime, Australian company Wizard Power is constructing a four-dish pilot plant in Whyalla, South Australia, to demonstrate an integrated dish and molten-salt storage system [35]. The heat transfer fluid will be superheated steam at 120 bar and 630 °C, produced by four 500 m^2 dish concentrators, originally developed at the Australian National University [36]. This will heat 106 tons of salt to 565 °C which, in the second stage of the plant construction, will provide 4 h of dispatchable power for a 560-kW$_e$ Siemens SST-060 turbine/generator set.

VIII. SUMMARY

After an initial development phase in the 1980s and 1990s, most notably with the U.S. Department of Energy's Solar Two project, molten-salt power towers are now a commercial reality. The 19.9-MW$_e$ Torresol Gemasolar power tower with 15 h of molten-salt storage, near Seville, Spain, began selling electricity into the Spanish grid in May 2011. Meanwhile, in the United States, construction will begin by August 2011 on SolarReserve's 110-MW$_e$ Crescent Dunes power tower with 8 h of storage in Nevada. These projects will join the growing list of commercial parabolic trough plants which are already operating with storage.

Advantages of the molten-salt power tower storage system include elimination of heat transfer oil and associated heat exchangers, a lower salt requirement, higher steam cycle efficiency, better compatibility with air cooling, improved winter performance, and simplified piping schemes. Near-term advances in molten-salt power tower technology include improvements to the thermal properties of molten salts and the development of storage solutions in a single tank.

Molten-salt power towers, and concentrating solar plants with storage in general, are well-placed to provide dispatchable power for 100% renewable grids in sun-belt countries. ■

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