Dispatchable Solar Power Plant

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Abstract. As penetration of renewable power increases, grid operators must manage greater variability in the supply and demand on the grid. One result is that utilities are planning to build many new natural gas peaking power plants that provide added flexibility needed for grid management. This paper discusses the development of a dispatchable solar power (DSP) plant that can be used in place of natural gas peakers. Specifically, a new molten-salt tower approach has been developed that is designed to allow much more flexible operation than typically considered in concentrating solar power plants. As a result this plant can provide most of the capacity and ancillary benefits of a conventional natural gas peaker plant but without the carbon emissions. The DSP plant discussed here is based on considerable analyses using sophisticated solar system design tools and in-depth preliminary engineering design. The Arizona Public Service (APS) utility system is used as an example of the benefits resulting from the methods presented. The analysis looks at a 230 MW net power cycle with a range of solar plant ratings. These results estimate that the cost of the DSP plant is less than 5% higher than a similarly sized and operated natural gas plant when APS reference fuel and emissions costs are included. The DSP plant cost is based on a single, first-of-a-kind plant, and it is likely that subsequent plants would be less expensive. In addition, the DSP plant represents an emission and carbon-free peaking power plant, free of future pricing risk. It provides local jobs rather than importing fuel. As Arizona has excellent solar resources and lower construction costs than neighboring California, an in-state DSP facility offers Arizona the potential to export carbon free capacity and peaking generation to California to help address the CAISO "Duck Curve."

INTRODUCTION

Many factors are driving the growth in renewable power generation. In the United States, although federal policies such as production and investment tax credits substantially improve the economics, it is state policies that have largely been responsible for progress in renewable generation. California, for example, has very aggressive carbon reduction goals that will have profound impacts on the conventional power marketplace throughout the entire western portion of the US. California's policies currently call for a 50% reduction in total carbon emissions by 2030 and an 80% reduction by 2050. This would require California to fully decarbonize its power sector to meet its 2050 goals for all sectors. This will require an unprecedented increase of renewable generation to achieve this goal.

Up until this point California has primarily focused on procurement of least-cost renewable energy and has not appropriately valued the other attributes that can be provided by generators. As a result, California has added and continues to add large amounts of solar and wind generation, referred to as variable renewable generation power. To date all the solar generation added is either from photovoltaic (PV) or concentrating solar power (CSP) plants without energy storage. With an increased percentage of variable renewable generation as a fraction of total electric supply, maintaining a stable electric grid such that energy supply is matched to meet energy demand at every point in time becomes more challenging. Figure 1 shows an example of what is referred to as the CAISO Duck Curve. CAISO is the California Independent System Operator that manages electric supply for about 80% of the power consumers on the California grid. This graphic highlights the impact of daytime solar generation on the overall system supply requirement at current and future levels of renewable generation, showing an example of the net generation that grid operator must supply on a mild spring day after accounting for generation coming from solar and wind generation. The increase in solar generation solar generation in future years is having two primary impacts on the management of the net supply. Note that it is significantly reducing the minimum daily net system load around noon and also resulting in steeper load ramps. These system characteristics require that baseload power plants be shut down and replaced with more flexible generation that can be ramped up and down to meet the changing system load. This is an inefficient situation, as many of the plants required to meet the evening ramp must be kept online through the minimum load point at part load during the middle of the day in order to be ready to meet the evening ramp, thus further reducing the head room for more efficient baseload generation. It is important to note that the Duck Curve results after California achieves its current goal of 33% renewable generation by 2020. As California moves towards its future goals of 50% and 80% carbon reduction, the problem with managing supply and demand will become even more problematic.

PV prices have come down so much in recent years that CSP technology can no longer compete directly with PV on a simple levelized cost of energy basis. Studies by NREL have shown that CSP plants with thermal energy storage (TES) can have higher value than PV alone because they have thermal energy storage that allows them to be dispatchable and receive capacity value [2]. Molten-salt tower (MST) technology in particular with its direct molten-salt storage is particularly well suited to provide dispatchable power. Historically, MST plants have been designed with large amounts of TES and large solar multiples such that the plants can be used to provide intermediate or baseload power. But because of their dispatchability, MST plants can also be designed to be very cost effective and operationally useful flexible peaking plants.

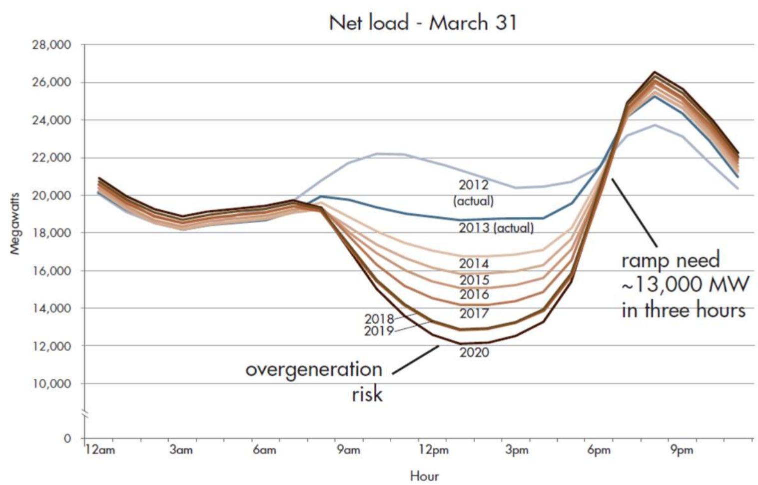


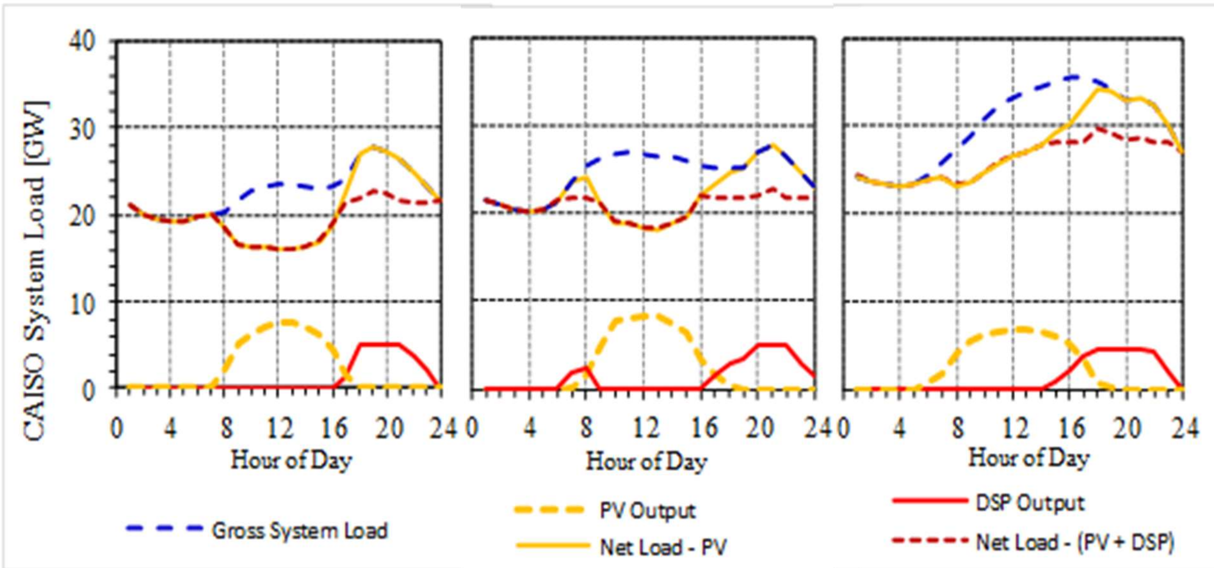
FIGURE 1. CAISO Duck Curve [1]

MST plants concentrate sunlight and are typically only cost effective in sunny desert climates like the U.S. Southwest. This region currently has an excess of baseload generating capacity and does not need new baseload power plants. However, it also has large amounts of variable resource generation causing increasing intermittency on the grid, requiring the need for flexible peaking power plants. This paper evaluates the suitability and economics of a MST solar power plant that has been designed to be a dispatchable solar power plant (DSP).

REQUIREMENTS OF A DISPATCHABLE SOLAR POWER PLANT

Seasonal dispatch

The solar system of MST technology collects and stores thermal energy separate from power block operation. This direct configuration allows the period of thermal energy collection to be separated from the period of power delivery. Depending on the relative sizing of the solar field, TES system and power plant, solar energy can be collected during the day and renewable power can be cost-effectively dispatched on an as-needed basis. With proper understanding of the market, it is quite possible to design an efficient MST plant for operation as a peaker, thus replacing the need for building a new natural gas peaker. Figure 2 shows the results of an analysis that looks at how DSP plants could be used as peakers to address the duck curve issue in California. The results show that the DSP plant can provide flexible capacity during all seasons of the year to the CAISO to help address the duck curve. Note the addition of generation from the DSP plant helps reduce the peak system demand and helps to smooth out the net system load. The analysis shows that an appropriately designed and located DSP plant can add substantial capacity value due to the strong correlation between peak load and solar resource in this area.



(a) **(b)** **(c)**

FIGURE 2. Example of a MS Tower DSP Plant in Operation: (a) Winter, (b) Spring, (c) Summer

<u>Operating Requirements</u>

This paper describes the conceptual design for a molten-salt tower dispatchable solar power plant. The goal is to develop a solar peaker plant that can operate more flexibly than conventional CSP plants have typically been designed to operate, allowing the plant to be marketed as a flexible resource that can be used reliably to meet a utility's peaking or load following requirements. To do this the CSP plant must be built with different operational capabilities than heretofore offered by a CSP molten-salt tower plant. The following are the operational requirements proposed for the DSP plant:

- *Start time*: The plant will be scheduled into the day ahead and hour ahead markets, and potentially into shorter interval markets, such as the energy imbalance market (EIM) at 5 and 15-minute intervals. The ability to start up and ramp to full load in less than 30 minutes for a warm start (the plant has been operated in the last 24 hours.
- Ramp rate: The ability to ramp from minimum load to full load in under 10 minutes.
- Reliability: The ability to have a high availability for starting and achieving rated output within a defined period.
- Capacity: The plant must be designed to meet the net output and duration when required, typically on during the hottest times of the year.
- Solar-to-electric efficiency: Although efficiency which affects annual electric generation will also need to be guaranteed, it is substantially less critical than for a plant based only on energy payments.

<u>Specific Example for a US Utility</u>

The design goal has been to identify and design a commercially valuable configuration of CSP technology that could have important opportunities in real markets in the near-term. To achieve this goal, this paper describes a comprehensive preliminary engineering design for a representative site in the Arizona Public Service (APS) utility territory that includes the selection of key equipment and evaluation of output performance and costs under a number of capacities, solar field sizes, operational scenarios, and equipment requirements.

APS is a regulated public utility that generates, transmits, and distributes electricity for sale in the U.S. state of Arizona. In mid-2017 APS issued a request for proposals (RFP) that specified a desire for "*new peaking capacity so that it can maintain a reliable power supply during peak demand periods and provide a flexible response to variable load requirements associated with increasing intermittent energy resources"* [3]. According to the APS 2017 integrated resource plan [4] that defines its power requirements over the next 15 years, the peak capacity requirement is expected to grow from 8 GWe to 13 GWe. Electricity production is expected to increase by over 50%, but carbon generation will reduce by 23% and water use will reduce by 29%. In order to meet these objectives, APS expects to retire 700 MW of coal generation, add 5400 MW of new natural gas generation, 200 MW of renewables, 400 MW of energy storage and 1000 MW of energy efficiency and demand side management. In addition, APS expects 3,300 MW of new rooftop solar and 500 MW of storage to be added on the customer side of the meter. APS has already acquired about 1200 MW of the new natural gas capacity it requires, and the 2017 Peaking Capacity RFP is looking 400 to 700 MW of additional peaking capacity in the form of natural gas generation, energy storage, or integrated renewables plus energy storage.

In the 2017 RFP, APS provided details of its needs, primarily oriented towards new flexible dispatchable summer resources from June to September from 3pm to 9pm. The APS system needs are very similar to what will be needed in California to address the Duck Curve. Figure 3 shows the annual APS time-of-day delivery periods for this peaking requirement, color-coded to define:

- most preferred: periods in red during summer months
- preferred: periods in yellow other times of the year
- less preferred: periods in green
- will not accept energy: periods in black.

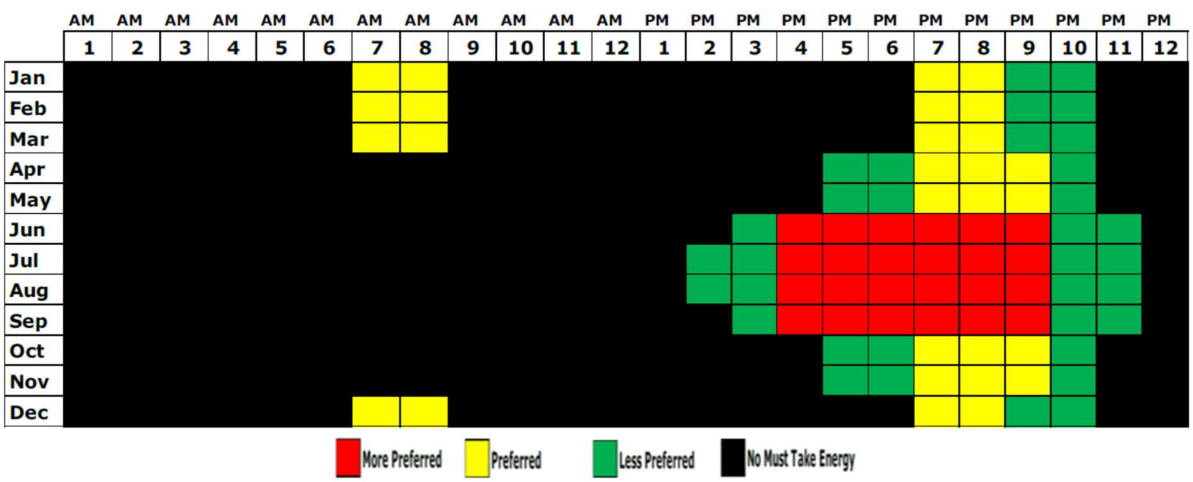


FIGURE 3 Time of Day Delivery Periods for APS 2017 Peaking Capacity RFP

The APS RFP allows two types of contractual structures to be proposed. The first is a conventional energy based power purchase agreement (PPA) where the project would be paid based on fixed pricing during each Time-of-Day (TOD) period. Power is not accepted during the black times, and pricing during the yellow ≥ 3X the price of the green, and red ≥ 9X the price of the green. This financial structure was available for the renewable plus energy storage technology options. The second option is a tolling agreement structure. This is the traditional structure used for natural gas peakers but was also for standalone energy storage projects. In a tolling agreement, the plant is paid a monthly capacity payment to stand by and be ready to operate. The utility controls when the plant is to be dispatched (operated) and supplies the fuel to run the plant. The plant then receives additional payments for starting and for their variable O&M costs. In this case, because the utility provides the gas, the plant must guarantee the heat rate (efficiency) of the plant. The performance scenarios shown in this paper are based on a tolling agreement, with the following specific characteristics:

APS Required Capabilities:

- The plant must be capable of operating for 4 hours at 45.6°C (114°F) and 20% relative humidity at 100% contract capacity,
- The plant must be dispatchable by APS with automatic generator control (load following capability),
- The plant must be capable of stable operation at a minimum operating level of 25% loading without exceeding emissions limits, and
- The plant must be available for operation for the summer peak period starting June 2021 but not before January 2021.

APS Preferred Capabilities:

- Capable of at least 2 starts per day,
- Have faster ramp rates,
- Have shorter minimum run, minimum down, and start-up times,
- Capable of being online and dispatchable in 10 minutes or less (quick start), and
- Interconnect to the APS transmission system near Phoenix.

ENGINEERING DESIGN

A comprehensive conceptual design was developed by Solar Dynamics and Sargent and Lundy for a DSP plant in the APS service territory, using the characteristics given above to define the operational and performance requirements of the plant. The conceptual engineering included the design, performance, cost and schedule of the DSP plant, based in part on input from selected vendors of specific key equipment. A site in Arizona was selected for use as a reference for the design. Solar Dynamics conducted the design optimization to determine the best configuration that met the APS operating requirements while minimizing cost. A critical difference between a molten salt tower (MST) DSP plant and more conventional MST plant configurations is the <u>relative sizing of the thermal rating of the solar plant to the design point of the power plant</u>, usually referred to as the solar multiple. MST plants have typically had solar multiples of 2.0 to 3.0 and annual capacity factors in the range of 50 to 75% [5-6]. In the case of the Crescent Dunes MST project, the solar field generates approximately two times as much thermal energy as the turbine requires at design solar conditions and the plant will have an annual capacity factor of about 52%. The DSP applications evaluated in this work using detailed design tools (see below) and optimized based on technical performance and project costs are characterized with solar multiples in the range of 0.6 to 1.0. Thus, in contrast to more base-loaded oriented MST plants, DSP plants operate for fewer hours during the year, with annual capacity factors of only 15% to 25%.

<u>Engineering Requirements</u>

Steam Turbine Generator (STG) – The DSP plant has aggressive goals for the operational performance and reliability of a CSP plant. Based on the APS requirements, the plant should be able to be on-line in under 10 minutes and be able to ramp to full load in under 30 minutes. This is much quicker than CSP plants are normally designed to start-up. Once the turbine is hot, it should be able to ramp up or down at 10% per minute. In addition, the plant should be able to operate at full rated capacity at 46°C when APS requires full capacity. Arizona is a hot desert climate with limited water resources, thus the goal is to minimize water use. As a result, wet, dry, and parallel wet/dry cooled power cycles have been evaluated to understand the performance, water consumption, and cost of each option. Siemens has developed a new fast-start version of its SST900 steam turbine as part of their efforts to develop more flexible gas combined cycle power plants [7]. The fast start Siemens SST900 steam turbine satisfies or exceeds all the desired operational requirements, with sizes available up to 250 MW gross output.

Steam Generator System (SGS) – Historically CSP plants have been built with conventional u-tube shell-and-tube heat exchangers, which have operating constraints that limit the performance of the plant under the daily start-up and cycling inherent in CSP plants. The DSP plant has much more aggressive start-up goals, so the conventional steam generators designs would be subject to unusually difficult specifications. This has led to the selection of an Aalborg CSP steam generator design that uses a once-though header style heat exchanger design that is capable of much more rapid thermal transients and can easily handle the rapid start and ramping required by the DSP plant [8]. In addition, Aalborg offers a standard modular design for a 50 MW SGS. The 250 MW plant will use five standard SGS units in parallel.

Molten-Salt Receiver – The solar plant is a molten-salt tower solar plant similar to existing commercial and pre-commercial installations. The molten-salt receiver can be supplied by a number of vendors with useful but limited commercial operational experience. In this evaluation, the plant is assumed to use a slip form concrete tower and a conventional dual circuit tubular molten-salt receiver based on an Aalborg design [9].

Thermal Energy Storage (TES) – The thermal storage system has been sized to meet the operating requirements of the APS TOD requirements for both summer and winter operation. In this case the TES is sized is set to allow the plant to store all the energy collected during the day in non-summer months and generate 5 hours during summer peak.

Heliostat Field – Several vendors can supply heliostats for the plant. For purposes of this evaluation, BrightSource Energy provided design assumptions for the heliostat field based on the 20.8 m^2 heliostat design used at its Ashalim project in Israel [10]. This heliostat uses PV for power with battery backup and wireless communication.

One unique aspect of the DSP plant being designed for Arizona is that the solar field has been constrained to fit on a one square mile (259 hectare) parcel because in the western United States land is laid out in square mile sections. This allows a standardization of design. A plant designed for one site in Arizona can easily be used with minor changes at other sites in Arizona, Nevada, California, or other western states. In addition, preliminary review of sites has been focused on agricultural land instead of undisturbed natural sites. These two features substantially increase the number of sites that are available and lead to simplification and acceleration of the plant permitting. Importantly, the square mile parcel size also constrains the maximum thermal rating of the plant.

Design Optimization

The most important single goal is to design a plant that meets the APS operational and performance requirements at the lowest possible cost. In this case the lowest cost is the lowest annual capacity payment and not the lowest levelized cost of energy. The capacity payment is an all-in cost that includes all capital costs, financing, taxes, and fixed and variable O&M, like an LCOE calculation but in units of dollars per kilowatt-year ($/kW-yr). The annual capacity payment can be calculated by multiplying the nominal LCOE by the annual generation and dividing by the net capacity of the plant.

Molten-salt tower plants have strong economies of scale in the tower and receiver as well as in the conventional power plant. Therefore the economic optimum is typically reached by increasing the capacity of the plant until either the drop off in the optical performance of the solar field or some other constraint limits the maximum capacity. In this case, two other factors limit the size of the plant, the first being the square mile solar field size and the second being the maximum size of the Siemens SST900 steam turbine (250 MW gross output). The analysis looks at the design optimum to deliver 6 hours of reliable capacity from 3 to 9 pm during the summer months as shown in Figure 3 and at 5 hours of from 4 to 9 pm. As more PV solar generation is added in the future, the summer peak is expected to reduce in duration and shift later in the evening.

A number of detailed system design tools were used in the optimization. First, we used NREL's SolarPilot software [11] to optimize the thermal rating of the square mile solar field. We looked at solar field designs with thermal ratings between 300 MWt and 500 MWt. For each solar field thermal rating, SolarPilot was used run to optimize the heliostat layout and spacing, tower height, and receiver sizing. The square mile site was able to hold reasonable heliostat field layouts up to about 400 MWt before dense packing of heliostats began to result in a significant drop in overall plant economics.

Next, NREL's Solar Advisor Model (SAM) [12] was used to evaluate the performance and economics of each solar field size and a range of power plant sizes. One input set to these analyses for site selection and plant design optimization and performance analysis consisted of solar resource and metrological data from the NREL National Solar Radiation Database (NSRDB) [13]. The NSRDB provides both typical meteorological year (TMY) and annual hourly data for the years 1998-2015 on an approximate 4-kilometer square grid. The reference site for the present work has a TMY annual direct normal insolation of 2900 kW/m2-yr (7.9 kW/m2-day).

The ability to accurately model the dispatch of power is essential to understanding the potential value and economics of the DSP plant. The built-in dispatch controls in SAM were initially used to model the APS dispatch schedule. This achieved reasonable first order results, but far from optimal dispatch, especially during winter periods with both morning and evening dispatch. NREL has added a new dispatch model to SAM (Wagner [14]) that allows the model to develop forecasts of future energy collection and optimize the power dispatch. We have found that the new Wagner dispatch optimizer did a credible job of optimizing the dispatch of the plant based on the time of delivery structure entered into SAM. This is illustrated in the results section below.

Fossil Alternative Cost Target

For a DSP plant to make financial sense, it needs to be close in cost and performance to its fossil alternative such that a utility would be willing to select the DSP plant over the fossil plant. It will likely need to be a comparison between two greenfield projects (i.e. new construction). Externalities, such as environmental benefits, fuel diversity, and infrastructure costs will need to be considered to help justify the DSP plant over a fossil alternative. To assess the attractiveness of a DSP plant, we have used the California Energy Commission's (CEC) cost of generation (COG) model to define the cost of fossil plants [15]. The COG model calculates both a levelized cost of energy (LCOE) in $/MWh as well as an annualized capacity cost in $/kW-yr. The COG model accounts for the capital cost, financing cost, taxes, fuel costs, environmental costs, and fixed and variable O&M costs. Part of the environmental costs include carbon costs. The COG model is an Excel spreadsheet with parametric values for low, mid, and high cost assumptions. The COG model is developed for evaluating costs of plants located in California, using methodologies that are meaningful to California. California considers carbon costs and uses a mid-range of carbon costs for their analysis. Arizona also includes carbon costs in analysis of new projects; however, their baseline costs are much lower than California. Additionally, plants built in Arizona are cheaper due to lower labor and development costs. The COG model assumptions were updated to reflect appropriate technology and cost assumptions for Arizona.

RESULTS

DSP plant cases were carried out for designs of 350, 400, 450, and 500 MWt solar plant ratings integrated into a 250 MW gross power cycle. Table 1 shows the design details, performance, capital cost, capacity cost and levelized cost of energy pricing. The net power from the plant is estimated to be approximately 230 MW. This is assumed to be the design net capacity of the plant with dry cooling and a design temperature of 46°C. Note the two smaller sizes include 5 hours of TES and are designed to meet a 5-hour summer peak (most preferred hours). The two larger cases assume 6 hours of TES and are designed to meet a 6-hour summer peak (most preferred hours). The 500 MWt solar field required a larger site, so we increased the land parcel to 1.25 miles on a side (340 hectare).

TABLE 1. DSP Plant Design, and Cost and Performance Results.

Plant Design	**Units**	**Case 1**	**Case 2**	**Case 3**	**Case 4**
Turbine Gross Output	MWe	250	250	250	250
Turbine Net Output	MWe	230	230	230	230
Solar Field Thermal Rating	MWt	350	400	450	500
Heliostat Area	m^2	667,454	787,645	1,030,189	937,531
Thermal Storage Size	hours	5	5	6	6
Land Area	hectare	259	259	259	340
Performance					
Annual DNI	kWh/m^2	2903	2903	2903	2903
Annual Net Sales	GWH	319	351	399	462
Annual Solar to Electric Efficiency	%	16.4%	15.4%	13.3%	17.0%
Annual Capacity Factor	% CF	15.8%	17.4%	19.8%	22.9%
TOD Performance					
Most Preferred (5 hrs)	% CF	90%	94%		
Most Preferred (6 hrs)	% CF			89%	93%
Preferred	% CF	83%	84%	89%	92%
Less Preferred	% CF	17%	19%	33%	48%
No Must Take	% CF	0.1%	0.0%	0.6%	1.7%
Cost					
EPC Overnight Capital Cost	$M	$592	$615	$662	$674
Total Project Cost	$M	$728	$754	$808	$827
PPA Price					
Annual Capacity Payment	$/kW-yr	$261	$267	$270	$269
Levelized Cost of Energy	$/MWh	$198	$185	$164	$141

The DSP plant performance estimates are shown in Table 1. The DSP plant configurations shown have annual capacity factors of 16% to 23%. The goal has been to develop designs that achieve high capacity factors during the most preferred and preferred periods, without generating a substantial amount of power during the no-must-take periods or the less preferred period.

Sargent & Lundy developed a detailed cost model for the 400 MWt variant of the DSP plant. Vendor quotes were supplied for all major equipment including: the steam turbine generator, air cooled condenser, wet cooling tower, steam generator system, receiver, concrete tower, thermal storage tanks, and heliostat field. Sargent & Lundy used its internal power plant cost database to estimate the costs of all remaining materials and systems based on material take-offs. Solar Dynamics extrapolated the capital costs for the other DSP plant configurations and added estimates for development, permitting, and other owner's costs. The capital cost estimates for each configuration are shown in Table 1. A detailed financial model was developed to allow accurate estimates of the required pricing for both energy and or capacity based PPA contracts.

The capacity payments and levelized cost of energy payment calculations in Table 1 assume a 30-year project life, include a 30% federal investment tax credit and financing by the federal finance bank. The plant with the smallest solar field thermal rating offers the lowest all in capacity payment, $261/kW-yr, but the highest LCOE at $198/MWh. Although the larger thermal ratings offer lower LCOEs the capacity payments are higher. This result shows that configuring the thermal rating (or amount of fuel) to the need can result in a more attractive result than just focusing on LCOE alone.

The 400 MWt solar field is selected as the preferred option fitting an APS plant scenario because it achieves a better capacity factor during the most preferred summer on-peak period. Figure 4 that shows the SAM output for the 400 MWt case. The figure shows that the new SAM dispatch model does an excellent job of delivering power to the priority hours and in this case, there is very little generation during the APS "No Must Take Energy" periods. The output during the more preferred period achieves a 94% capacity factor overall, but it is clear from the figure that there are some cloudy periods, especially in July and August. In general, the DSP plant achieves a capacity factor of around 100% in June and capacity factors around 90% during the other summer months. It is worth noting that this is for the TMY case. We should also note that we are assuming 100% plant availability for this figure so the capacity factor reflects the solar resource limitations without power plant availability effects.

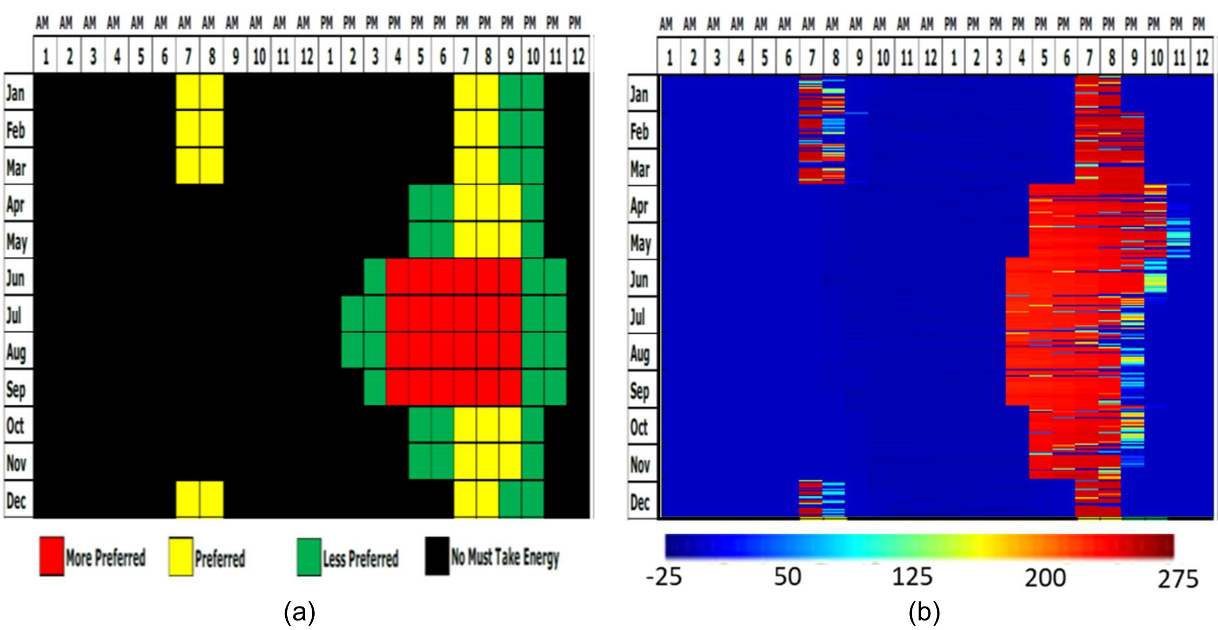


FIGURE 4 Sample DSP Plant Application: (a) APS 2017 Peaking Capacity RFP Time of Delivery Periods, (b) SAM Optimized DSP Dispatch Model for Nominal 400 MWt Solar Field (TMY Case)

Table 2 highlights that 86% of the generation of the plant is produced during the more preferred and the preferred periods. Although increasing the solar plant rating above 400 MWt lowers the average LCOE, it comes primarily adds additional generation during the less preferred period, or periods when APS will not purchase power.

Table 2. DSP Plant Output (400 MWt Case) During APS TOD Periods

APS TOD Periods	Capacity Factor	% of Total Generation
More Preferred (5 hrs)	94%	38%
Preferred	84%	48%
Less Preferred	19%	13%
No Must Take	0.2%	0.6%

Using the CEC COG model, we estimated the all-in capacity cost of a GE 7FA frame combustion turbine operating at the same capacity factor to be approximately $250/kW-yr, based on the economic assumptions in the APS 2017 IRP [4], which assumes relatively low gas and carbon costs in the future. These results suggest that the cost of the DSP plant is less than 5% more than the natural gas plant. It is worth pointing out that there is significant overlap in the cost uncertainties of both the fossil and DSP plants. The DSP cost is based on a single, first-of-a-kind plant, and it is likely that subsequent plants will be less expensive. In addition, the DSP plant represents an emission and carbon free peaking power plant, free of future fuel and emissions pricing risk. It provides local jobs rather than importing fuel. As Arizona has excellent solar resources and lower construction costs than California, an in-state DSP facility offers Arizona the potential to export carbon free capacity and peaking generation to California to help address the CAISO Duck Curve.

CONCLUSION

The dispatchable solar power (DSP) plant is being developed as part of a U.S. Department of Energy, technology-to-market R&D contract. The bottom-line results show that a carefully designed molten salt tower plant can be optimized to operate as a renewable peaking power resource. To reach this conclusion, a package of NREL-designed modeling tools partnered with in-depth conceptual design engineering by S&L were used to develop a DSP plant that compares favorably with a reference fossil alternative with regard to performance and cost of capacity. The DSP plant cost estimate takes advantage of a 30% investment tax credit in the US but conservatively assumes relatively low natural gas and carbon pricing assumptions. International sites with higher gas pricing could potentially be competitive against the fossil alternative as well. The DSP plant described here is not intended to replace the more conventional use of MST technology for baseload or intermediate load power; rather, the purpose has been to show that a DSP plant can very effectively serve an additional peaking application where there is need for flexible generation.

NOMENCLATURE

APS	Arizona Public Service
CAISO	California ISO a.k.a. California Independent System Operator
CEC	California Energy Commission
CF	power plant capacity factor
COG	CEC cost of generation model
DOE	US Department of Energy
DSP	dispatchable solar power
Duck Curve	see Figure 1
EIM	energy imbalance market
EPC	engineering-procurement-construction contractor
GWH	gigawatt-hour (electric)
kW-yr	kilowatt-year (electric)
kWh	kilowatt-hour (electric
LCOE	levelized cost of electricity
MST	molten-salt tower
MW	megawatt (electric)
MWh	megawatt-hour (electric)
MWt	megawatt-thermal
NREL	US National Renewable Energy Laboratory

NSRDB	NREL National Solar Radiation Database
O&M	operation and maintenance
PPA	power purchase agreement
PV	photovoltaic
RFP	request for proposal
SAM	NREL Solar Advisor Model
S&L	Sargent and Lundy
SGS	steam generator system
STG	steam turbine generator
TES	thermal energy storage
TMY	typical meteorological year
TOD	time-of-day

ACKNOWLEDGEMENT

The authors thank the SunShot Tech 2 Market Program at the U.S. Department of Energy EERE for supporting the development of the Dispatchable Solar Power Plant evaluation under contract DE-EE0007579. The work presented here is based on the preliminary findings from that effort.

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