

CONCENTRATING SOLAR THERMAL TECHNOLOGY STATUS

*INFORMING
A CSP ROADMAP
FOR AUSTRALIA*



AUGUST 2018



About ITP

The ITP Energised Group, formed in 1981, is a specialist renewable energy, energy efficiency and carbon markets consulting company. The group has offices and projects throughout the world.

IT Power (Australia) was established in 2003 and has undertaken a wide range of projects, including designing grid-connected renewable power systems, providing advice for government policy, feasibility studies for large, off-grid power systems, developing micro-finance models for community-owned power systems in developing countries and modelling large-scale power systems for industrial use.

ITP Thermal Pty Ltd was established in early 2016 as a new company within the ITP Energised group, with a mandate to lead solar thermal projects globally. In doing so it accesses staff and resources in the other ITP Energised group companies as appropriate.

About this report

This report is ITP's input on CSP industry background to a Roadmap study lead by Jeanes Holland and associates working with ITP. Energeia and Flinders University AITA. This report serves as a technical appendix to the roadmap and it can also be read as a stand alone document.

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LIST OF ABBREVIATIONS

AC	Alternating current
AEMO	Australian Energy Market Operator
AITI	Australian Industrial Transformation Institute (Flinders University)
ANU	Australian National University
APPA	Spanish Renewable Energies Association
ARENA	Australian Renewable Energy Agency
ASI	Australian Solar Institute
ASTRI	Australian Solar Thermal Research Institute
AU	Australian
AUD	Australian Dollar
AZ	Arizona
BOM	Bureau of Meteorology (Australia)
BOP	Balance of Plant
CAGR	Compound average growth rate
CC	Combined cycle
CERC	Central Electricity Regulatory Commission (India)
CHP	Combined Heat and Power
CLFR	Compact linear Fresnel reflector
CO ₂	Carbon dioxide
COAG	Council of Australian Governments
CPV	Concentrator Photovoltaics
CRC	Cooperative Research Centre
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CSP	Concentrating Solar Power
CST	Concentrating Solar Thermal
CUF	Capacity Utilisation Factor
DLR	German Aerospace Centre
DNI	Direct Normal Solar Irradiance
DOE	Department of Energy
DSG	Direct Steam Generation
EIA	U.S. Energy Information Administration
EOR	Enhanced Oil Recovery
EPC	Engineering, procurement, and construction
ESMAP	Energy Sector Management Assistance Program
ESTELA	European Solar Thermal Electricity Association
ETFE	Ethylene tetrafluoroethylene
FIT	Feed-in-tariff
FOAK	First of a kind
GDP	Gross Domestic Product
GHG	Greenhouse gas
GIS	Geographic Information System

GJ	Gigajoule
GT	Gas turbine
GW	Gigawatt, unit of power – subscript “e” for electric, “th” for thermal
GWh	Gigawatt-hour, unit of energy (1 GW generated/used for 1 hour)
HTF	Heat Transfer Fluid
HTST	High Temperature Solar Thermal
IEA	International Energy Agency
IRENA	International Renewable Energy Agency
ISCC	Integrated solar combined cycle
ISF	Institute for Sustainable Futures
ITP	ITPower Thermal Pty Ltd or other group companies
kW	Kilowatt, unit of power – subscript “e” for electric, “th” for thermal
kWh	Kilowatt-hour, unit of energy (1 kW generated/used for 1 hour)
LCOE	Levelised Cost of Electricity
LFR	Linear Fresnel reflector
LPG	Liquefied petroleum gas
MAN	Maschinenfabrik Augsburg-Nürnberg
MASEN	Moroccan Agency for Solar Energy
MNRE	Ministry of New and Renewable Energy (India)
MPa	Megapascal (unit of pressure; 1 MPa = 10 bar)
MW	Mega Watt, unit of power = 1000kW
MWh	Megawatt-hour, unit of energy (1 MW generated/used for 1 hour)
NOAK	N th of a kind
NEM	National Electricity Market
NPV	Net Present Value
NREL	National Renewable Energy Agency
NREP	National Renewable Energy Program (Saudi Arabia)
NSEC	National Solar Energy Centre at CSIRO Newcastle
NSM	National Solar Mission (India)
NSW	New South Wales
NT	Northern Territory
O&M	Operations and Maintenance
OEM	Original equipment manufacturer
ORC	Organic Rankine Cycle
PPA	Power purchase agreement
PV	Photovoltaic
QLD	Queensland
R&D	Research & Development
RD&D	Research development & deployment
RE	Renewable Energy
REAOL	Renewable Energy Authority of Libya
REE	Red Eléctrica de España
REIPPPP	Renewable Energy Independent Power Producer Procurement Programme (South Africa)

RET	Renewable Energy Target
REZ	Renewable Energy Zone
RFI	Request for information
RMIT	Royal Melbourne Institute of Technology
SA	South Australia
SAM	System Advisor Model (NREL)
SBP	Schlaich Bergermann and Partners
sCO ₂	supercritical CO ₂
SEGS	Solar Electric Generating Station
SM	Solar multiple
SolarPACES	Solar Power and Chemical Energy Systems
STE	Solar thermal energy
SWIS	South Western Interconnected System
TAS	Tasmania
TOD	Time-of-delivery
TWh	Terawatt-hour, unit of energy (1 TW generated/used for 1 hour)
UAE	United Arab Emirates
UNSW	University of New South Wales
US, USA	United States of America
USD	US Dollar
UTS	University of Technology Sydney
UV	Ultraviolet
VIC	Victoria
WA	Western Australia
WACC	Weighted average cost of capital

EXECUTIVE SUMMARY

Concentrating Solar Thermal Power (CSP) systems use systems of mirrors to focus direct beam solar radiation to high temperature receivers that capture the energy for power generation. There are four main CSP technologies, in order of deployment volume they are: Parabolic Trough, Central Receiver Tower, Linear Fresnel and Paraboloidal Dish.

Parabolic trough 100 - 450°C, High commercial maturity.		<p>The tubular receiver is fixed to the focal line of the array of parabolic mirrors, which track the sun along one axis throughout the day. Trough systems can heat a heat transfer fluid such as synthetic oil, or generate steam directly for process heat or power generation. Deployment of parabolic trough CSP plants at end of 2017 was 4.35 GW_e.</p>
Linear Fresnel 100 - 450°C, Medium commercial maturity		<p>Removing the need for a moving receiver and flexible couplings, the linear Fresnel system is similar to a trough concentrator in that it provides heat over the same temperature range. Long, semi flat mirror strips in parallel rows track the sun independently, to focus direct beam radiation on a linear receiver that is fixed on a non-moving tower. Deployment of linear Fresnel CSP plants at end of 2017 was 158 MW_e.</p>
Heliostats and tower 300 - 2000°C, Medium / High commercial maturity		<p>For higher temperatures, the heliostat field plus tower arrangement is available. Many Individual mirrors on double-axis tracking devices are all simultaneously moved to reflect sunlight to a single receiver on a tower, which typically reaches temperatures of around 600°C. In principle, much higher temperatures can be obtained. Deployment of heliostat and tower CSP plants at end of 2017 was 612 MW_e.</p>
Dish 300 - 2000°C, Low commercial maturity		<p>A mirrored paraboloidal dish system can also offer high temperatures and with a higher efficiency than tower systems. However, this approach is less commercially mature than tower systems. There are currently no commercial operating utility scale CSP plants using this technology.</p>

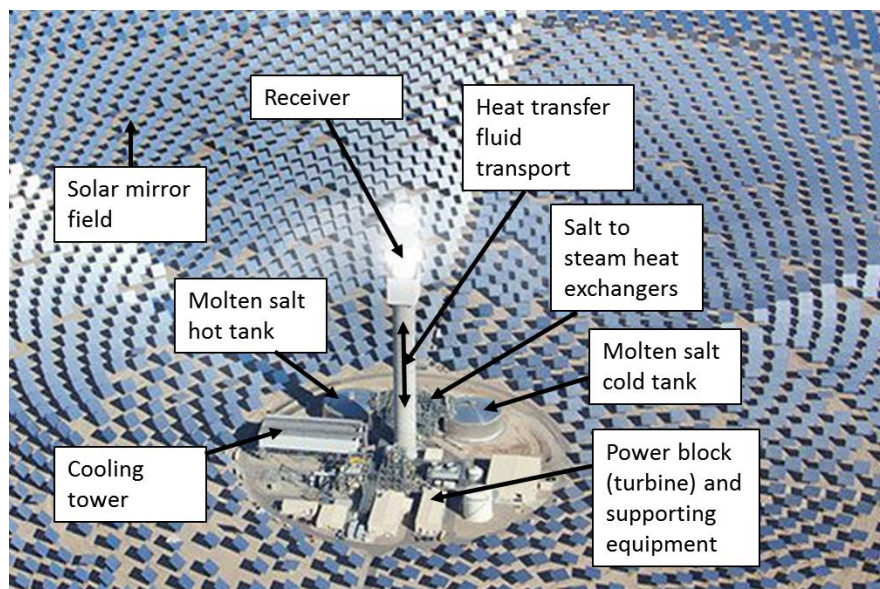
CSP is relatively commercially mature, although total deployment is still small compared to wind and PV generation. With increasing political pressure and momentum for renewable energy to mitigate climate change and reduce dependence on fossil fuel, the sector is attracting increasing interest for power generation due to:

- The established low cost approach of thermal energy storage combined with synchronous generation with inherent inertia.
- The rapidly growing share in variable renewables in certain regions leading to increasing demand for energy storage and dispatchable renewable power generation
- Decreasing CSP component and overall system costs
- increasing maturity and acceptance of CSP technologies

CSP Technology

While trough plants have the longest track record of operation and account for the bulk of systems deployed to date, tower plants are emerging as a more favoured option for power generation, due to the higher temperatures and efficiencies as well as more cost-effective energy storage that has been achieved. Linear Fresnel and Dishes have their own advantages and are also being actively pursued.

CSP plants are complex integrated systems made up of a series of subsystems. This is illustrated for the particular case of a molten salt tower plant in the figure below.



Key subsystems are:

- The mirror field that gathers solar radiation and directs it to a focal point by tracking the sun during the day.

- The receiver that intercepts the radiation and converts it to high temperatures.
- The heat transfer fluid system that takes heat from the receiver and transports it to storage and / or power block.
- The thermal storage subsystem that is typically based on two tanks of hot liquid salt but can use other processes also.
- The power block and associated equipment that is typically based on a steam turbine and electrical generator.

CSP power plants are attracting increasing interest due to their ability to store large amounts of energy and provide dispatchable electricity supply. The current industry standard approach is to use a mix of molten nitrate and potassium salts as a heat storage medium that is moved between a 'cold' tank at around 290°C to a 'hot' tank at close to 400°C or 600°C depending on the concentrator type.

The bulk of the world's electricity is generated with steam turbines. One of the advantages of CSP is the ease with which this new source of heat can be applied to the dominant power generating technology. Consequently the vast majority of the CSP systems presently in operation use steam turbines.

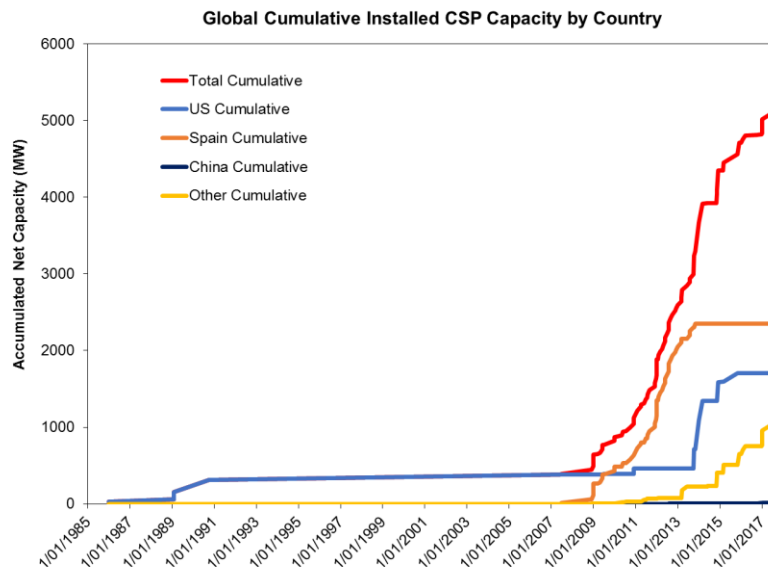
Other power cycles are considered for future application to CSP. These include Stirling engines, Brayton cycles (air turbines) and organic Rankine cycles. Considerable RD&D attention is currently applied to supercritical CO₂ turbines. These offer the potential for higher conversion efficiencies and smaller and more modular power blocks.

CSP systems can be hybridised in various ways. Commercial systems have been built which use fossil fuel boosting. Conversely fossil fired generators can have solar thermal fields added to boost output over fossil only operation. Of recent times increasing attention is paid to system developments that hybridise a low cost PV field with a CSP plant with storage, with coordinated operation and connection to the grid.

CSP fields can provide heat for industrial processes other than electricity generation. An attractive approach is to provide both electricity and heat via a combined heat and power configuration whereby steam is only partially expanded in a turbine to produce electricity and then directed at a suitable temperature to the industrial heat use.

Global status

At the end of 2017, global installed and operational net (nameplate) CSP power generation capacity was around 5.1 GW_e. While the US and Spain are where most of the early development occurred, in the last few years first CSP plants have also been completed in Morocco, South Africa, India and UAE. Several additional countries have multi-megawatt projects under construction or under development, including China, Chile, Morocco, Israel and Saudi Arabia.



The 5.1 GW_e of installed capacity at the end of 2017, is made up of 64 plants with size 50 MW_e or larger constituting over 90% of the installed capacity, with the remainder comprised of about 32 smaller pilot type projects. Approximately 40% of existing plants and most new plants incorporate thermal energy storage.

All the trough plants, dating from the mid 1980s onwards, have solid track records of consistent performance year by year. This includes the many plants with thermal energy storage. Tower plants with direct heating of molten salt are currently being favoured internationally however there is only one plant with an established track record, the Gemasolar 20MW tower system in Spain, established in 2013. The Crescent Dunes plant in Nevada at 100MW with 10 hours storage is the biggest so far, it is still working through teething problems. There are three other such plants under construction at present in Chile, Morocco and China.

Services and benefits

Solar energy based generation in general offers the prospect of non-polluting sustainable electricity. Solar thermal generation with storage offers extra values beyond the baseline of variable renewable generation. The key differentiating concept is dispatchability, system operators are able to predict and indeed control the generation levels from a solar thermal plant within the constraints of its configuration in a way that cannot be done with variable renewables. CSP plants with extended hours (>10) of thermal storage are effectively baseload in their nature, on the other hand more agile plants with bigger power blocks relative to solar field and thermal storage can act more like traditional peaking plants.

CSP plants offer a range of features in addition to providing emissions free electricity, that are rewarded either implicitly or explicitly in the market place. These include:

- moving energy sales to high demand periods,
- ancillary services (spinning and non-spinning reserves, etc),
- whole electrical network avoided cost,
- community / society benefits, and
- option / hedging value.

Australian CSP systems

Despite its world leading solar resources, Australia is yet to be a major player in the CSP industry and does not have any 'utility scale' CSP systems in place. However Australia has 'punched above its weight' in many of its contributions from an RD&D point of view.

Beginning in the 1980's small pilot systems were built, trough units at Meekathara in WA and dishes at White Cliffs in NSW. Liddell power station in the hunter valley is home to a 9.3MW_{th} linear Fresnell array that was completed in 2012. The Victorian company Solar Systems installed multiple dish based concentrating PV systems in remote towns from 2000 onwards and also a large array in Mildura (40 dishes 1.5MW), before going out of operation.

The Australian National University is home to two of the world's largest dish concentrators as a result of an active R&D group dating to the 1980s. CSIRO in Newcastle is the biggest R&D group and operates two experimental tower systems at its site. Lake Cargelligo in NSW is home to a multi-tower 3.5MW_e system (now mothballed) which incorporates graphite based thermal storage in its receivers. Also in NSW is the 6MW_{th}, 1MW_e pilot multi-tower system established by the company Vast Solar.

The largest CSP array in Australia was built for the Kogan Creek power station solar boost project in Queensland. This 135MW_{th} linear Fresnel array was intended to feed steam to the coal fired power station and boost its output by 44MW_e. It has however never been completed following the exit of the company that built it, from solar activities. The largest successful system is the Sundrop farms 36MW_{th} system near Pt Augusta in SA. While this system only generates 1 MW_e of electricity, the bulk of its energy is used for desalination and heating to support the greenhouse development.

In addition to these activities, the Australian government via, first the Australian Solar Institute and later the Australian Renewable Energy Agency, has invested over \$95m in CSP R&D. Among the research institutions, CSIRO, ANU, University of Adelaide and University of South Australia have the largest CSP research programs. There are also CSP research groups at the University of Queensland, RMIT, UNSW and other organisations, with growing industry linkages.

Previous Australian studies

There have been many studies over the past decade looking at aspects of how large scale commercial CSP might be realised in Australia.

The context and priorities for CSP in Australia have been examined with a 2008 High Temperature Solar Thermal Roadmap commissioned on behalf of the Council of Australian Governments, (Wyld Group, 2008). Key conclusions were that solar thermal represented a major opportunity in Australia, with an ultimate potential for grid-connected systems in the order of 20,000 MW_e.

The not for profit group Beyond Zero Emissions produced a 'Zero Carbon Stationary Energy Plan' (Wright and Hearps, 2010). This was a detailed case study of a rather optimistic scenario based on large wind turbines and CSP tower / heliostat type plants with molten salt storage to provide 100% of Australia's stationary energy needs in 10 years.

Leading up to the Federal Government's Solar Flagships program, AECOM (2010) completed a 'Pre-feasibility study for a solar precinct' for the NSW government and the Queensland Government commissioned Parsons Brinckerhoff together with input from the Clinton Climate Initiative to produce the 'Queensland Concentrated Solar Power Pre-feasibility Report' (Parsons Brinckerhoff, 2010). In WA 'Site options for Concentrated Solar Power Generation in the Wheatbelt', Clifton and Boruf (2010), was produced for the Western Australian Wheatbelt Development Commission and Evans and Peck have completed a detailed study of renewable energy potential including CSP for the Mid West and Pilbara regions of WA on behalf of the Department of Resources Energy and Tourism (Evans and Peck, 2011a, 2011b).

ITP has previously completed a detailed study, *Realising the Potential for Concentrating Solar Power in Australia*. This 2012 study reviewed the status of the global industry, activities and previous studies in Australia. It also analysed construction costs based on international experience transferred to Australian conditions. Construction costs, combined with O&M costs, and agreed financial parameters were used to analyse the Levelised Cost of Energy (LCOE) from hypothetical Australian CSP plants. A range of non-technical barriers were considered and policy recommendations were made. It was also concluded that based on likely rates of global CSP deployment and likely range of cost reductions per doubling of capacity, that LCOE and income in Australia could converge sometime between 2018 to 2030 (Lovegrove et al., 2012).

The Institute for Sustainable Futures (ISF) from the University of Technology Sydney, lead a 2013 study to investigate the potential network benefits of CSP systems with thermal storage in the Australian NEM (Rutovitz et al., 2013). That showed that the implicit value of network support payments could contribute to the business case for plants ranging from 8MW to 120MW.

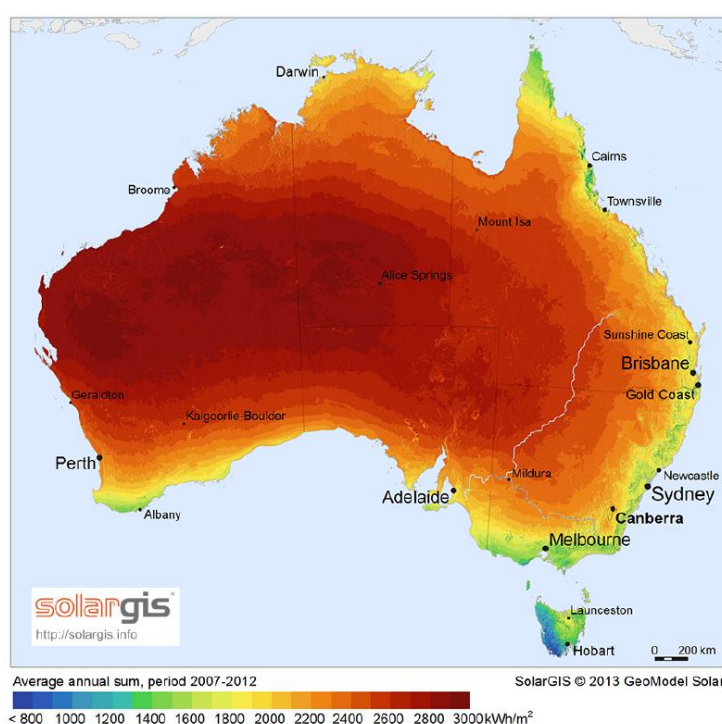
ARENA has supported a number of specific CSP feasibility studies. A feasibility study was carried out by Abengoa of a pre-commercial 20 MW_e solar power tower plant with 7 hours of thermal energy storage in Perenjori, WA. In 2015, Alinta completed a study to assess the viability of a 50 MW_e CSP plant located near Port Augusta, SA. This study was carried out in the lead up to the closure of the Northern Power station (brown coal fired) that was operated by Alinta at that site. A study led by Ratch Australia considered the feasibility of converting the existing 180 MW coal-fired Collinsville Power Station in Queensland to a 30 MW hybrid solar thermal/gas power station.

Subsequent to these studies, ARENA released a formal request for Information to the global CSP industry in July 2017. The result was:

- 31 responses building on experience from every significant CSP system globally.
- Directly expressed and implied interest in involvement in CSP deployment in Australia.
- Universally positive views on the future of CSP.
- All responses referred to the key advantage of cost effective, integrated thermal energy storage and the characteristics of dispatchable generation via synchronous generators.
- A clear indication that a large scale competitive CSP process in Australia would be well subscribed

Power station performance and requirements

There are various issues that would determine a preferred site choice for a CSP plant. The level of solar Direct Normal Irradiation (DNI) resource is an obvious and major one.



The broad CSP industry consensus is that DNI needs to be above 2,000/kWh/m²/year. This implies that anywhere west of the great divide in Australia can be considered. It also indicates that there is considerable potential in the north of Victoria in addition to all the other mainland states.

Predicting the output of CSP systems is complex. At steady state, performance is linked to the instantaneous level of DNI and also thermal losses that depend on ambient temperature and wind

and cooling tower performance that also depends on ambient temperature. In addition there are finite times required for start-up procedures and thermal inertia in components that effect behaviour as inputs change.

There is great flexibility in the way a CSP plant can be configured. The size of the solar field, the capacity of the storage system and the size of the power block can all be chosen independently. Increased solar field, particularly with the addition of energy storage can increase the utilization of the power block, thus increasing capacity factor. However, increasing the solar field and storage capacity also increases capital costs. Systems can be optimised for lowest levelised cost of energy (LCOE) for a particular site. However a lowest LCOE system is not necessarily the economically optimal plant to build. If the main underlying driver is responding to a time varying electricity spot price (linked to the demand and supply balance), a system with reduced storage and solar field size may be preferable as the increase in LCOE may be offset by the increase in average energy sale price from limiting generation to higher value periods.

Annual generation levels are proportional to DNI levels to a good approximation, noting also that there is a minimum level of DNI required before there is any net generation. Comparing some key Australian locations illustrates this:

State or territory	Site	AEMO Renewable Energy Zone	Annual DNI kWh/m ² /a	Annual Generation GWh/a	Capacity factor %	Relative LCOE %
NT	Alice Springs	n/a	2,588	548	60%	94%
QLD	Longreach	near 3	2,453	516	57%	100%
NSW	Broken Hill	12	2,420	480	53%	108%
SA	Port Augusta	21	2,281	453	50%	113%
VIC	Mildura	13	2,205	435	48%	118%
TAS	Launceston	near 29	1,621	293	32%	174%

Note: The above relative LCOEs are referenced to a baseline of a 115 MWe Power Tower Plant with 10 hours storage at Longreach with air cooled condenser.

Environmental issues are all manageable, but careful site choice and community engagement is essential. Issues of risk of heat transfer fluid oil spills (for troughs), tower visual impact and water usage are all important but routinely dealt with in projects around the world.

The impact on the habitat of local fauna is best assessed and dealt with during initial site assessment to minimize costly delays during construction. For example, the Ivanpah project in the Californian Mojave Desert experienced delays and additional costs due to its suspected impact on the habitat of endangered desert tortoises at the location of the plant.

The issue of bird deaths has been raised at the large tower projects in the US. Following proper investigation and improved management of mirror fields, deaths are found to be at a level commensurate with bird strike deaths on all man-made structures.

Water is required for CSP plants for:

- condenser cooling,
- make-up for steam/condensate cycle,
- collector cleaning, and
- other general purposes including, fire fighting, staff use and general services.

Of these, condenser cooling when evaporative (wet) cooling towers are employed, is by far the largest water consumer. There is an increasing trend to adopt dry cooling towers for this reason.

During the height of construction in Spain, typical 50MW_e trough plants took 18 months from ground breaking to connection. First of a kind projects that represent new technology configurations typically take up to twice as long as this and also have much more extended commissioning and de-bugging phases.

Cost of CSP Energy

Building on recent work and available information, the cost model adopted for this study is:

Subsystem	Specific Installed cost	Baseline capacity	Power law size exponent
Solar Field including receivers and towers as appropriate	\$0.46m/MW _{th}	600MW _t	0.9
Storage system	\$26,000/MWh _{th}	1429MWh _t h	0.8
Final conversion including power block boiler heat exchangers and other BOP	\$2.40m/MW _e	100MW _e	0.7

A further premium would apply for first of a kind systems in the country.

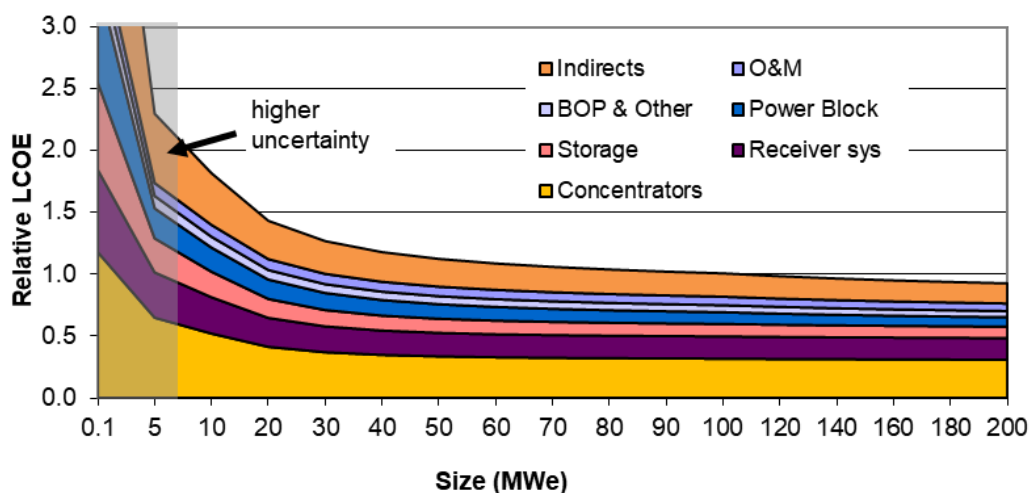
With these parameters the cost of a system of any configuration can be estimated. Each subsystem cost is further adjusted for size using the power law exponent shown¹. Operation and maintenance costs for a large (100MW +) plant have been approximated at 2% of capital cost per year.

¹ Total cost proportional to size to the power n, where the exponent n is less than 1 and often around 0.7.

Using this cost model and predictions of annual generation, the levelised cost of energy can be determined based on a cost of capital assumed. Thus for a 100MW tower system using 10 hours molten salt storage at Longreach in Queensland and a solar field sized to minimise LCOE the , results predicted are:

Total specific cost	LCOE at 6% WACC	LCOE at 6.5% WACC	LCOE at 7% WACC
m\$6.6/MW	\$117/MWh	\$122/MWh	\$127/MWh

These numbers increase considerably for smaller systems. A major impact on the economics of small systems is that below 50MW the conversion efficiency of turbines drops drastically, a small 2MW turbine may be less than half the efficiency of a 100MW unit. Costs of O&M also increase and there is less economy of scale benefit.



Thus LCOE at 50MW_e could be expected to be 10% higher than at 100MW_e, but this increases to 40% at a 20MW_e system size and considerably more at even smaller sizes.

Future trends

Different compound growth curves can be fitted to the progress of CSP in the past. If the entire effort from the first US plant at the beginning of 1985 to the completed 5.1 GW at the end of 2017, is fitted, the result is a historic CAGR over nearly three and a half decades of about 19.6% pa. However, there was a long period of zero activity between 1990 and 2006, the latest phase from 2007 to 2017 has averaged 27.5% pa growth. If global CSP growth would continue along these past growth trajectories, installed capacity would reach between around 50 and 100 GW by 2030.

The available evidence suggests that the cost of CSP systems and hence the energy they produce, should drop by around 15% for every doubling of global capacity, consistent with all new energy technologies. If this is combined with an expected compound growth rate of 20%/year, the result would be a halving of cost by about 2035. In reality, such cost reductions are expected to result from; technical improvements, volume production efficiencies and faster and more efficient on site construction.

Globally and in Australia RD&D continues on many fronts and aims to help improve the economic performance by addressing:

- Construction cost reduction
- Improvements in the efficiency of energy conversion
- Reductions in O&M costs
- Broadening the market value and range of application.

A major focus of international effort is on the development of the supercritical CO₂ power cycle together with higher temperature energy storage and advanced receivers to compliment it. Linear concentrators are also making progress with new larger and more cost effective collectors and potential direct heating of molten salt and other heat transfer fluids.

Conclusion

CSP is a global industry with a 30 year track record of utility scale power generation. It is capable of sustained compound growth in installed capacity and is analogous to the PV industry around 1 decade previously. CSP offers cost effective dispatchable renewable electricity via the integration of thermal storage. In Australia with around 15 GW_e of baseload coal plants expected to retire by 2040, establishing a modest compound growth rate in CSP installed capacity in the near future, would allow a significant fraction of that coal capacity to be replaced in an orderly and timely manner.

Globally the industry favours systems built at around 100MW_e for cost effectiveness. Whilst the first plants in the 100MW_e scale may seem like large undertakings, it needs to be seen in the context that around 15 of these is needed to replace one large scale coal plant. However there are many systems built at 50 MW_e and smaller systems are technically possible. Smaller systems however face reduced turbine efficiencies higher relative O &M costs and reduced economies of scale. Despite this if extra value can be derived from network support in fringe of grid opportunities, support for systems in the 10 – 50MW range makes sense however agencies and policy makers need to be wary of unrealistic expectations.

Overall with increasing attention paid to the need for dispatchable renewable generation in addition to variable generation from PV or wind, the coming years should hold considerable opportunity for CSP both in Australia and around the world.

1. INTRODUCTION

Concentrating Solar Thermal Power (CSP) systems use systems of mirrors to focus direct beam solar radiation to high temperature receivers that capture the energy for power generation. CSP is relatively commercially mature, although total deployment is still small compared to wind and PV generation. With increasing political pressure and momentum for renewable energy to mitigate climate change and reduce dependence on fossil fuel, the sector is attracting increasing interest for power generation due to:

- The established low cost approach of thermal energy storage combined with synchronous generation with inherent inertia.
- The rapidly growing share in variable renewables in certain regions leading to increasing demand for energy storage and dispatchable renewable power generation
- Decreasing CSP component and overall system costs
- increasing maturity and acceptance of CSP technologies

This report provides the background to a roadmap for CSP in Australia that is being developed by Jeanes Holland and Associates working with ITP, Energeia and the Flinders University AITA.

Topics addressed include:

- Current technology status and ongoing developments with major cost reduction potential
- Status of global CSP market in terms project volume and growth forecasts
- Review of CSP activity in Australia
- CSP power station performance analysis and requirements
- Costs of CSP in Australia
- Services and additional grid benefits of CSP
- Future trends.

2. CSP TECHNOLOGY

There are four main CSP technologies (see Table 1), in order of deployment volume they are: Parabolic Trough, Central Receiver Tower, Linear Fresnel and Paraboloidal Dish.

Table 1: The main CSP technology types

Parabolic trough 100 - 450°C, High commercial maturity.		<p>The tubular receiver is fixed to the focal line of the array of parabolic mirrors, which track the sun along one axis throughout the day. Trough systems can heat a heat transfer fluid such as synthetic oil, or generate steam directly for process heat or power generation. Deployment of parabolic trough CSP plants at end of 2017 was 4.35 GW_e.</p>
Linear Fresnel 100 - 450°C, Medium commercial maturity		<p>Removing the need for a moving receiver and flexible couplings, the linear Fresnel system is similar to a trough concentrator in that it provides heat over the same temperature range. Long, semi flat mirror strips in parallel rows track the sun independently, to focus direct beam radiation on a linear receiver that is fixed on a non-moving tower. Deployment of linear Fresnel CSP plants at end of 2017 was 158 MW_e.</p>
Heliostats and tower 300 - 2000°C, Medium / High commercial maturity		<p>For higher temperatures, the heliostat field plus tower arrangement is available. Many individual mirrors on double-axis tracking devices are all simultaneously moved to reflect sunlight to a single receiver on a tower, which typically reaches temperatures of around 600°C. In principle, much higher temperatures can be obtained. Deployment of heliostat and tower CSP plants at end of 2017 was 612 MW_e.</p>
Dish 300 - 2000°C, Low commercial maturity		<p>A mirrored paraboloidal dish system can also offer high temperatures and with a higher efficiency than tower systems. However, this approach is less commercially mature than tower systems. There are currently no commercial operating utility scale CSP plants using this technology.</p>

While trough plants have the longest track record of operation and account for the bulk of systems deployed to date, tower plants are emerging as a more favoured option for power generation, due to the higher temperatures and efficiencies as well as more cost-effective energy storage that has been achieved. Linear Fresnel and Dishes have their own advantages and are also being actively pursued.

CSP power systems built to date almost exclusively use steam turbines to generate electricity in a similar manner to fossil fuel fired power stations. They provide synchronous generation with inherent inertia. There are advanced power cycles with higher efficiencies that are the subject of research and development activities and may come into play in the future.

CSP systems capture the direct beam component of solar radiation. Unlike flat plate photovoltaics (PV) or non-concentrating thermal systems, they are not able to use radiation that has been diffused by clouds or dust or other factors. This makes them best suited to areas with a high percentage of clear sky days, in locations that do not have smog or dust.

There are many worthwhile CSP websites published by developers and interest groups. One of the most definitive and technically reliable is that maintained by the International Energy Agency's SolarPACES program (SolarPaces, 2018).

CSP plants are complex integrated systems made up of a series of subsystems. This is illustrated for the particular case of a molten salt tower plant in Figure 1.

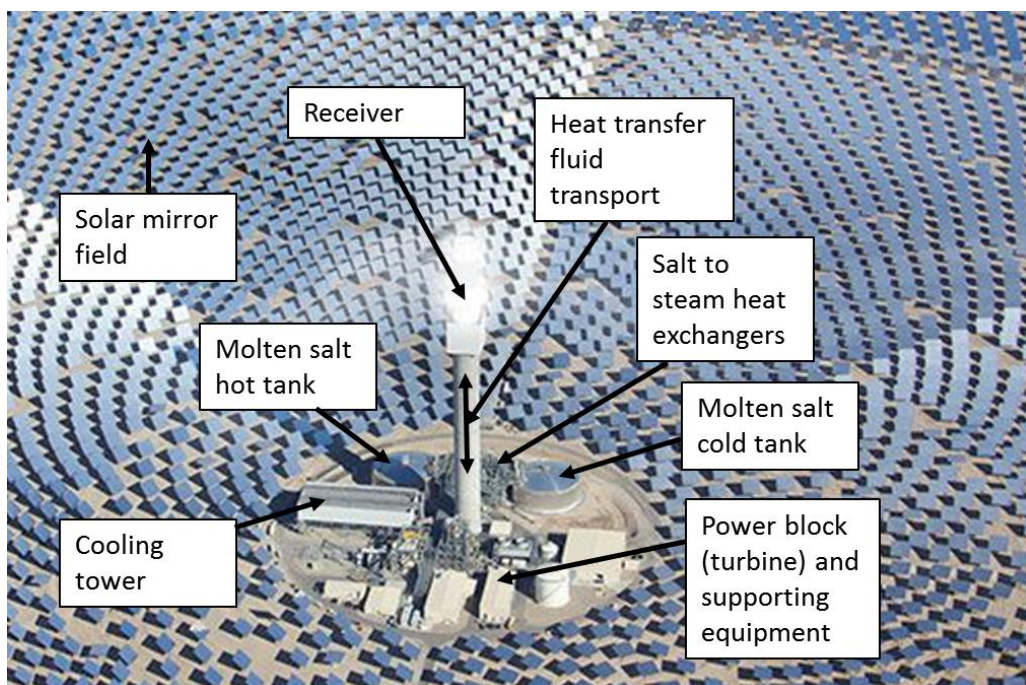


Figure 1: Subsystems in a molten salt tower plant.

Key subsystems are:

- The mirror field that gathers solar radiation and directs it to a focal point by tracking the sun during the day.
- The receiver that intercepts the radiation and converts it to high temperatures.
- The heat transfer fluid system that takes heat from the receiver and transports it to storage and / or power block.
- The thermal storage subsystem that is typically based on two tanks of hot liquid salt but can use other processes also.
- The power block and associated equipment that is typically based on a steam turbine and electrical generator.

CSP power plants are attracting increasing interest due to their ability to store large amounts of energy and provide dispatchable electricity supply. The current industry standard approach is to use a mix of molten nitrate and potassium salts as a heat storage medium that is moved between a 'cold' tank at around 290°C to a 'hot' tank at close to 400°C or 600°C depending on the concentrator type.

2.1. Concentrator types

2.1.1. Parabolic Trough

Parabolic trough-shaped mirrors produce a linear focus on the receiver tube along the parabola's focal line. The complete assembly of mirrors plus receiver is mounted on a frame that tracks the daily movement of the sun on one axis, as shown in an example in Figure 2.



Figure 2: Parabolic Trough Collector (Nevada Solar One, picture R Dunn).

Relative seasonal movements of the sun in the other axis result in lateral movements of the line focus, which remains on the receiver but can have some spill at the row ends.

Trough systems using thermal energy collection via evacuated tube receivers are currently the most widely deployed CSP technology. In this configuration, a thermal oil heat transfer fluid (HTF) is usually used. The receiver tubes in most of the trough plants are complex. They incorporate a glass tube with an inner metal pipe and an evacuated space between. The inner pipe has a selective surface coating, with high absorptivity in selective solar wavelengths and low emissivity for infrared wavelengths. Process heat applications may use simpler, non-evacuated receivers.

Standard trough systems operate up to around 400°C and their upper temperature is currently limited by the chemical stability of the thermal oil heat transfer fluid used. Trough systems using molten salt heat transfer fluid that can go up to around 500°C, have been demonstrated and are commercially promoted but are less proven than thermal oil based systems.

The Solar Energy Generating Systems (SEGS) plants in Southern California were the first large CSP power plants in the world. They are built with parabolic trough technology. There are nine plants in total built by the Luz company of Israel, with construction beginning in 1984 and ending in 1990. The first two plants were 15 MW_e each, SEGS 3 to 6 were 30 MW_e each and the final three plants were 80 MW_e each. They all feature trough units of 5.8m aperture, fitted with mirrors of shaped back-silvered low iron glass.

The SEGS plants have continued to generate effectively for over 25 years with an increasing availability over that time. They continue to operate with over 99% availability and have shown reductions in O&M costs over their operating life (Richter et al., 2009). This track record establishes the trough technology approach as truly proven. It means that new trough projects are able to attract debt financing in preference to the other technologies and consequently is the reason that most of the new trough projects have been a very similar configuration to the original SEGs plants.

There is now a trend towards larger aperture troughs as one way of reducing costs and improving the concentration ratio. Examples include the Flabeg Ultimate Trough™ and the Abengoa Space Tube® with aperture widths of 7.5 m and over 8 m, respectively (Flabeg, 2018; Marcotte and Manning, 2013). Another novelty in parabolic trough technology are mirror films, such as the ReflecTech® silvered polymer mirror sheets used by the SkyFuel SkyTrough® with a 7 m wide aperture (SkyFuel, 2018), Figure 3. Mirror films are light, are not prone to breakage and promise to be cheaper than glass mirrors, and may allow for cost savings in the support structure and foundation. They must however, overcome the challenges of durability under the effects of UV radiation, dust and cleaning processes.



Figure 3. SkyFuel SkyTrough® collector using ReflecTech® mirror films (image: SkyFuel)

A new trough technology specifically for harsh dusty and windy environments such as those encountered in oilfields in the Middle East has been recently developed by Glasspoint Solar. The 6 m aperture trough collector is contained in a glasshouse with automated cleaning system on the roof to protect it from environmental influences (Figure 4). This concept has been deployed at 1 GW_{th} in the Miraah enhanced oil recovery project in Oman and is planned or proposed for further such projects in California and the Middle East.



Figure 4. Glasspoint trough collector enclosed in glasshouse for harsh environments (image: Glasspoint).



Figure 5. Airlight Energy parabolic trough CSP plant, Ait Baha, Morocco (image: Airlight Energy).

Another novel trough concentrator design with even larger aperture (close to 10 m) has been developed by Airlight Energy SA. The technology uses silvered polyester mirror films which are mounted on a precast concrete frame and enclosed in an inflated ETFE membrane structure. The receiver tube conducts an air flow to remove the collected heat, in combination with a thermal storage system of packed beds of rocks. A 4 MW_{th} pilot system has been demonstrated in a cement plant in Morocco (Airlight Energy, 2018), Figure 5.

2.1.2. Central Receiver Tower



Figure 6: Central Receiver system, Spain.(Gemasolar plant, owned by Torresol EnergyTorresol Energy)

A Central Receiver / Tower system involves an array of heliostats (large mirrors with two axis tracking) that concentrate the sunlight on to a fixed receiver mounted at the top of a tower.

This allows sophisticated high efficiency energy conversion at a single large receiver point. Higher concentration ratios are achieved compared to linear focussing systems and this allows thermal receivers to operate at higher temperatures with reduced losses.

A range of system and heliostat sizes have been demonstrated. There is no clear trend with regard to the optimal heliostat size. The size of commercial heliostats varies widely from around 1 m² up to around 140 m² (Coventry and Pye, 2014). For example the different heliostat technologies used in the Sundrop CSP Project, the Ivanpah plant, the Crescent Dunes plant and the Atacama-1 plant have reflector areas of 2.2 m², 15 m², 115.7 m² and 140 m², respectively. With regard to system size, among international industry players, the most attractive size for tower systems is in the order of 100 to 200 MW_e. Smaller systems are less cost effective, while larger systems are limited by radiation losses between heliostats and receiver. To resolve size constraints of heliostat/tower systems, some advocate smaller modular systems, such as that developed by eSolar or by the Australian company Vast Solar (Figure 7) whereby multiple small towers collect energy for a single power block. This has yet to be applied to a large system in the 20 – 100MW_e size range.



Figure 7. Vast Solar modular multi-tower solar field in Jemalong, NSW (source: Vast Solar). 6MW_{th} array operates a 1MW_e turbine.

The heliostat field constitutes the largest cost component of tower systems, typically constituting around 20% to 35% of the total installed plant costs. Heliostat costs have been experiencing rapid cost reductions over recent years. Current costs for the installed solar field are around 100 USD/m² (reflector area), down from around 170 USD/m² in 2015. Further cost reductions to around 75 USD/m², in line with the 2020 SunShot target, have been predicted (Mehos et al., 2016; Pfahl et al., 2017).

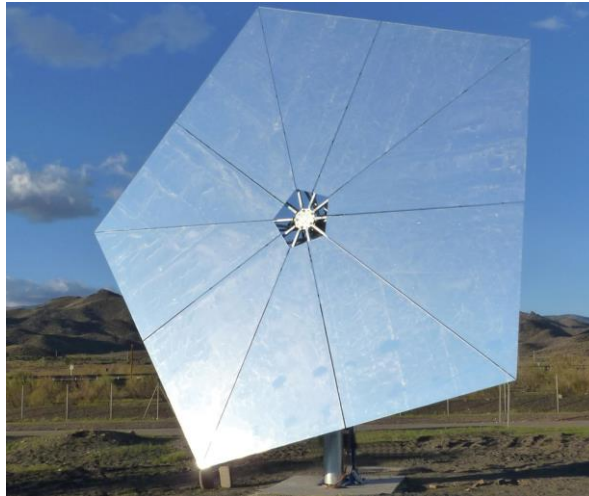


Figure 8. SBP Stellio heliostat (source: SBP).

Whilst commercial plant heliostats are becoming close to a commodity item, cost saving innovations continue to be tried. For example a new heliostat design has been developed recently by Schlaich Bergermann and Partners that promises to match current cost targets while also exhibiting superior optical performance (Schlaich Bergermann and Partner, 2018). Other R&D activities on heliostats are currently underway to develop anti-soiling coatings to avoid reflectivity loss due to soil deposition on the mirrors and reduce labour and water requirements for mirror cleaning (Fernandez-Garcia et al., 2017).

2.1.3. Linear Fresnel Reflectors

Linear Fresnel Reflector (LFR) systems produce a linear focus on a downward facing fixed receiver mounted on a series of small towers. Long rows of flat or slightly curved mirrors move independently on one axis to reflect the sun's rays onto the stationary receiver.

The fixed thermal receiver not only avoids the need for rotary joints in the HTF pipeline, but also works to minimise convection heat losses from the receiver because it has a permanently down-facing cavity.

Typically water is heated and boiled directly in the receiver to generate saturated steam of around 270°C at the outlet of the receiver. Systems super heating steam or molten salt HTF to over 500°C have also been demonstrated but are not yet deployed at large scale.

The proponents of the LFR approach argue that its simple design with near flat mirrors and less supporting structure, which is closer to the ground, outweighs the lower overall optical and thermal efficiency.



Figure 9: Puerto Errado 2, 30MWe LFR plant, Spain, (picture Frenell GmbH).

There are several current efforts to pursue LFR systems with pilot plants built in a number of countries. There have been two high profile efforts that have lead to utility scale plants.

In 2002, Solar Heat and Power Pty Ltd was founded to commercialise linear Fresnel technology developed in Australia. The company was taken to the US and renamed Ausra in 2007, before it was bought by French power company Areva (now Orano) and renamed Areva Solar in 2010. In 2005, Solar Heat and Power completed a 1 MW solar booster (a solar thermal heat input to an existing fossil-fired power plant) at the Liddell coal power station in NSW and in 2008 Ausra completed the 5 MW Kimberlina pilot plant in California. Areva Solar's largest project was the 125 MW Dhursar CSP project which was completed in 2014. This is the largest CSP plant using linear Fresnel technology in the world and the largest CSP plant in Asia. Areva Solar also started construction of the largest solar boost plant (44 MW) at the Kogan Creek coal power station in QLD for CS Energy. This should have been Australia's first utility scale CSP plant however work stopped in 2014 and despite the fact that all of the solar array components have been fabricated and are on site there is no progress on completing it at present. Areva essentially exited the solar business in 2014 and has not provided the follow up support expected to either complete Kogan Creek or overcome reported issues at Dhursar. The main driver for Areva's exit appears to be the financial pressures on the parent company resulting from the downturn in the nuclear industry at a time when the solar business had not progressed to a position of positive cashflow.

The other major effort was by the German company Novatec Solar. After construction and operation of a 1 MW_e pilot plant in Spain and also extending the Liddell solar boost system at Liddell Power Station to 9 MW (currently not operational) they went on to build the 30 MW PE2 project in Puerto Errado Spain (Figure 9). This plant continues to operate well for its owners. Novatec Solar subsequently passed into administration and the company founders now continue

to develop the technology via Frenell GmbH. The Frenell LFR technology is currently being installed as a 'solar boost' configuration to a coal plant in India. Frenell have also tested a system for direct heating of molten salt at the 1MW_e PE1 plant in Spain. This is now their preferred configuration for future plants.

2.1.4. Paraboloidal Dishes

Dish systems, like troughs, exploit the geometric properties of a parabola, but as a three dimensional paraboloid (Figure 10). The reflected direct beam radiation is concentrated to a point focus receiver and in CSP systems can heat this to operating temperatures between 500 °C and more than 1000°C, the same temperatures as tower systems.

Dish systems offer the highest potential conversion efficiencies of all the CSP technologies, because they always present their full aperture directly toward the sun and avoid the "cosine loss effect" that the other approaches experience. Furthermore, they concentrate the beam radiation in a single focal point achieving higher temperatures resulting in higher efficiencies when converting thermal to electrical energy. The technology is still under demonstration and relatively high investment costs. There have been many prototypes demonstrated since the 1970s.

Much of the international effort on dishes has been for combined dish engine systems. The engine is typically a Stirling system that is directly connected to the receiver where the focus point is located. The heat concentrated in the engine is transformed into mechanical energy driving a generator producing electricity. The receiver, engine and generator are all contained in a single unit including the tracking system, mounting structure and system control. The solar dishes are relatively small when compared to other CSP technologies with system sizes in the range of 3 to 30kW_e. Unfortunately this configuration does not easily lend itself to incorporation of thermal energy storage. Whilst efforts to progress the dish engine approach sought to target markets for small off grid systems, PV costs are now far lower and dominate that sector. The dish engine configuration has subsequently not progressed. There are however efforts to develop high temperature dish integrated thermal storage for Stirling Engines. United Sun Systems for example, (<http://www.unitedsunsystems.com>) is building on the legacy of past Dish Stirling work and promoting a system where the engine is moved to the back of the dish and coupled to an integrated thermal store that is charged using a combined receiver / heat pipe.



Figure 10: Ripasso Solar Dish Stirling Unit (image: Ripasso)

However dishes can also be applied in large arrays for centralised power generation. Direct steam production in the receivers or thermochemical conversions have been demonstrated. The future of dishes is likely to be in this configuration and driven by the wish to capture the benefits of higher efficiency and modularity characteristics.

2.2. Electricity Generation

A range of different thermal to electric energy conversion systems can be applied to the various concentrator types.

With CSP systems, the concentrated solar radiation is collected on a receiver that for most thermal systems is fabricated from tubes. A HTF is typically pumped through the receiver tubes and back to a central plant where it is circulated through heat exchangers to produce steam in a boiler. Most existing plants (being trough plants) use a thermal oil as the HTF, however direct molten salt heating is increasingly favoured and direct steam generation has also been applied as well as other approaches still in the R&D phase.

The two axis tracking, point focus systems concentrate the sun to a higher degree than the linear focus options. As a result, if thermal energy conversion is employed, the hot receiver is smaller and so heat losses are less for any given operating temperature. Consequently the Tower and Dish options are usually operated at higher temperatures which allows for higher efficiencies in

power generation.² This performance advantage is offset by the more complex geometry and hence higher specific costs of manufacture per unit area of reflector.

For Tower systems, a heat transfer fluid passing through the receiver absorbs the highly concentrated radiation and typically transfers it to ground level for steam-based power generation. Tower systems have been operated with water/steam, molten salts and air-based receivers. Pressurised air receivers at temperatures of 1,000°C or more have been demonstrated at pilot scale to directly operate gas turbine cycles. Ultimately, combined cycle operation, where the exhaust heat from a high temperature gas turbine is used to operate a lower-temperature turbine cycle, typically a steam Rankine turbine cycle, offers the possibility of 50% or more cycle efficiency.

2.2.1. Steam turbines

The bulk of the world's electricity is generated with steam turbines. All the major solar concentrator types have been applied to steam production for use in steam turbine energy conversion. One of the advantages of CSP is the ease with which this new source of heat can be applied to the dominant power generating technology. Consequently the vast majority of the CSP systems presently in operation use steam turbines.

A Rankine cycle using a steam turbine works by:

- compressing pure feedwater to high pressure (over 10 MPa for example);
- boiling and superheating steam in a boiler which may be in the focal point, or may be heated with a heat transfer fluid using a heat exchanger;
- expanding the steam to low pressure via a series of turbines that drive a generator; and
- at the end of the expansion process, condensing the low pressure steam with the aid of a cooling tower and then re-using the condensed water in the cycle.

As can be seen from Figure 11, currently Rankine power cycles used in CSP plants have design thermal efficiencies³ ranging from 37.5% for parabolic trough plants to 41.5% for solar tower systems (Stein and Buck, 2017). Key features that improve efficiencies include various stages of steam bleed from the turbines that can then be used to progressively heat feedwater prior to use in boilers, plus use of thermal energy to re-heat steam between turbine stages. Managing the chemical composition of the cycle water is an important part of the process. A fraction of the water is periodically “blown down” (sent to waste) to aid maintaining feedwater quality as salts and corrosion products and other contaminants would otherwise accumulate. Feedwater is replaced via on site reverse osmosis systems that provide highly deionised and purified water.

² A component of the efficiency of heat engines is the temperature difference between the heat entering the engine (in this case the heat transfer fluid) and leaving the engine / steam turbine, (Carnot's theorem).

³ Thermal efficiency of a power cycle is percentage of heat input to the cycle that is converted to mechanical work (power), the rest being rejected back to the environment as low-grade heat.

The Rankine cycle has a higher conversion efficiency the higher the temperature and pressure the steam is at turbine entry (in common with all heat engine cycles). At a more pragmatic level, systems are more efficient if they are built as larger units and run at full load. In the power industry overall, most of the size efficiency advantage is achieved at the 50 to 100 MW_e scale. However, most large-scale fossil fuelled power generating units are around 500 MW_e. For a CSP application, a larger turbine requires a large field, which results in increased energy losses of various kinds⁴, and so there is a trade off against turbine size, with a 250 MW_e unit being suggested by many observers as offering the lowest cost of energy.

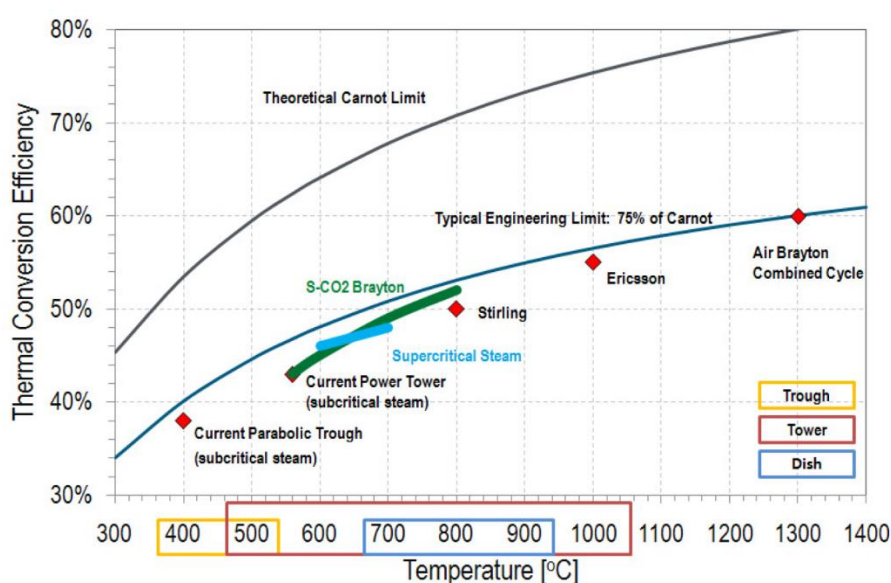


Figure 11. Thermal efficiencies vs. temperature for thermal power cycles used or conceivable for CSP plants (Siegel et al., 2013).

50 MW_e has been the most common CSP plant size in the past, with the majority of 50 MW_e plants built in Spain during the CSP boom between 2007 and 2013, as a result of the feed-in tariff policies in place then. Several of the recently built CSP plants have sizes exceeding 50 MW_e, such as the 377 MW_e Ivanpah tower plant (made of 3 separate 125 MW_e units), the 250 MW_e Solana parabolic trough plant (2 x 125 MW_e), and the 125 MW_e Dhursar linear Fresnel plant. Several projects currently under development or under construction also exceed 50 MW_e, including the 150 MW_e Aurora plant in Port Augusta, SA. The largest CSP system likely to be built in the coming years is the 700 MW_e DEWA parabolic trough plus tower plant near Dubai, which will also likely be comprised of several separate units in parallel.

The most efficient steam turbines work at around 700°C steam inlet temperature. Trough and Fresnel linear concentrators are however limited to around 400°C if oil Heat Transfer Fluid (HTF)

⁴ Distributed collector fields have increased losses from HTF piping, Tower plants suffer losses in optical performance from outer heliostats.

is used and up to 500°C if Direct Steam Generation (DSG) is used. Tower and Dish systems are able to reach the temperatures needed for the highest possible steam turbine inlet temperatures and pressures.

State of the art steam turbines are now produced that work at so called 'supercritical' conditions, for maximum conversion efficiency. This is steam above 22 MPa and 600°C, conditions at which water / steam changes phase continuously rather than boiling. As yet, supercritical systems have not been applied to CSP plants.

A major area of difference between solar and fossil operation of steam turbines is the intermittent and changing nature of solar input, this has two impacts:

- the wish to cycle turbines up and down faster and more frequently than in fossil-fuelled operations; and
- the wish to run at part load more frequently.

Whilst addition of thermal storage helps to mitigate these impacts, directly transferring technologies and practices from conventional generation does not give optimal results.

Turbine manufacturers have been developing specific turbines that better fit the operational conditions of CSP plants being more flexible with daily stop/start cycling's as well as with fast start ups (Siemens, 2018). The start-up time is mainly limited by the thermal stress of the turbine and precise control is needed to avoid compromising the lifetime of the component or even machine failure.

For example (Price, 2018) reports that the new Siemens fast start SST-700 Flex plant 30 (see Figure 12) features:

- 30 Minutes from start to full capacity in a normal daily start
- Ramp rates of 10% per minute
- 25+ year life with multiple starts per day.

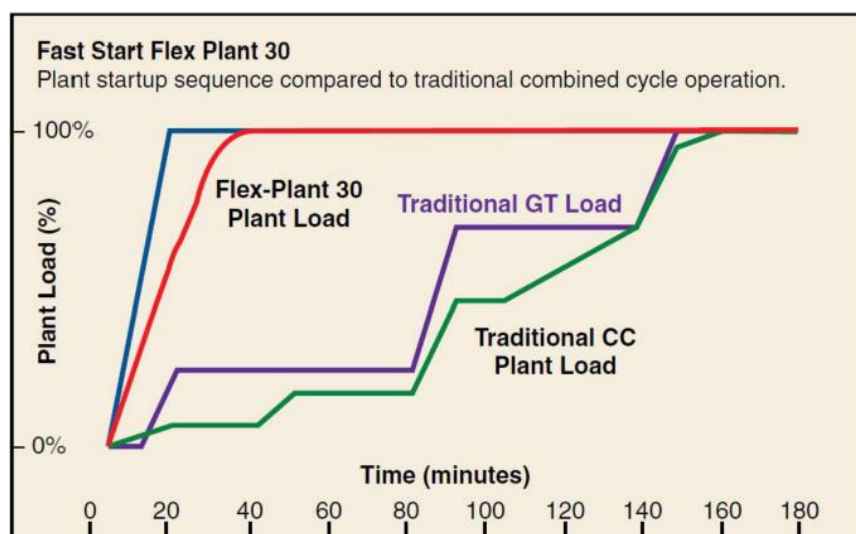


Figure 12: Steam Turbine Advanced Fast Loading

2.2.2. Other CSP power cycles

There is a mismatch between the temperatures of beyond 1000°C reachable with solar towers and the maximum temperatures of the sub-critical steam power cycles used in CSP systems today. In order to improve the efficiency and costs of CSP plants, developers aim to utilise the efficiency potential of tower power plants better through the use of higher-temperature power cycles and combined cycles.

Options for advanced power cycles for large-scale CSP plants include the existing supercritical steam Rankine and the air and helium Brayton cycles, as well as potential new supercritical CO₂ (sCO₂) Brayton cycles. To further optimise the thermal efficiency of CSP plants beyond that achievable with single power cycles, combined cycles can be considered, where the thermal energy rejected by a high temperature power cycle, typically a Brayton cycle, is utilized to generate additional power in a lower temperature power cycle. Candidate low temperature cycles include the organic Rankine, Kalina and Goswami cycles (Besarati and Goswami, 2017).

A recent discussion of advanced power cycles for CSP can also be found in (Stein and Buck, 2017).

Organic Rankine Cycles

An Organic Rankine Cycle (ORC) is fundamentally the same as a steam Rankine cycle, however it uses a lower boiling point organic fluid to better match its operation to lower temperature heat sources. ORC systems typically achieve better efficiencies than steam turbines for very small systems (less than a few MW_e) and at low operating temperatures, making them good candidates as a low temperature cycle in combined cycle power plants.

However, the capital and O&M costs are higher per installed MW_e than for a water/steam system. ORC technology is also being actively pursued by various geothermal proponents because of its better match to lower temperature sources. ORC systems have been applied to a few modest sized linear concentrator CSP systems.

Stirling Engines

A Stirling Engine is an externally heated engine with reciprocating pistons that uses a gaseous working fluid, usually hydrogen or helium or possibly air. The ideal cycle is made up of a mix of constant temperature and adiabatic (zero heat transfer) processes. In principle, it is capable of the highest thermodynamically possible conversion efficiencies between two constant temperature limits - the input and output temperatures.

The Stirling Engines contemplated for CSP applications to date have all been small (in the tens of kW_e range), although large, fossil fuelled systems for submarine propulsion do exist. Dish-mounted Stirlings incorporate receiver, engine and generator in a single package at the focus.

Even at small size, Stirling engines achieve high conversion efficiencies of around 40% for inlet temperatures of 800°C. Dish Stirling systems consequently offer very high overall solar to electric conversion efficiency, with total solar to AC electric efficiencies of around 30% at design point solar irradiance, reliably reproduced. Stirling systems can be used for much smaller systems than Rankine cycles.

However as with all CSP technologies overall cost of energy, not efficiency is the key investment criteria. The biggest challenge for Stirling engine technology is reducing O&M and capital costs.

Currently, no Stirling solution with integrated energy storage exists, but concepts have been proposed using latent heat (phase change) energy storage. An alternative approach to reaching dispatchability is hybridisation with natural gas. Both solutions could provide a route to smaller, more modular yet highly efficient dispatchable CSP systems for example for fringe of grid applications.

Brayton Cycles

The Brayton cycle is the basis of jet engines and the turbo generators used in '*gas turbine*' power stations. It is a common misconception that '*gas turbines*' are named that way because they burn natural gas.

They are '*gas turbines*' because a gas (e.g. air) is the working fluid. In fossil driven mode, any hydrocarbon fuel (eg aviation fuel, diesel, LPG, propane or landfill gas), could be burnt to achieve the required heating. Alternatively solar heat could be used to raise the temperature of the compressed air before expansion. With temperatures before expansion of around 1000°C needed for efficient operation, this is only likely to be achieved with Central Receivers or Parabolic Dishes. Demonstration CSP systems using a Brayton cycle have been operated.

In fossil fuel driven applications, a combined cycle power plant uses a gas turbine with its high temperature exhaust gases then directed to a '*heat recovery steam generator*' that provides steam for a steam turbine cycle. The combined conversion efficiency is around 55-60% and represents the highest thermal to electric conversion efficiency solution currently available commercially. A major attraction with applying the Brayton cycle to CSP applications is to also implement combined cycle operation with either steam or ORC bottoming cycles in a similar high efficiency manner.

The combined cycle approach is used with natural gas fired turbines in the power industry. To adapt it to solar operation, receiver systems that heat air to more than 1000°C are needed. This has been demonstrated internationally and CSIRO (ARENA, 2010) has also tested an air receiver in conjunction with Mitsubishi Heavy Industries. Development of an energy storage system compatible with such temperatures is a further key R&D challenge. The ANU's investigation of high temperature thermochemical energy storage targets this application (ARENA, 2014a).

Supercritical CO₂ Cycles

A new advanced power cycle using supercritical CO₂ (sCO₂) is currently under development and increasingly favoured for next-generation CSP plants. It is essentially a modified closed Brayton cycle using the high pressure and high density CO₂ that is kept above its critical pressure of 7.38 MPa and 30.98°C as the working fluid.

sCO₂ cycles aim to utilise the relatively high density of supercritical CO₂ to reduce the pumping power requirement and hence improve the thermal efficiency over that of subcritical Brayton cycles. Supercritical CO₂ cycles offer several potential advantages, including (Besarati and Goswami, 2017; Mehos et al., 2017):

- high potential efficiency >50%
- good match for temperatures of solar towers (up to around 850°C)
- compactness, i.e. lower weight and volume (e.g. estimated diameter of a 3 MW_e sCO₂ turbine is approx. 15 cm)
- lower thermal mass
- potentially lower installation and O&M costs due to simpler design and smaller size

The IEA CSP Technology Roadmap predicts the development of sCO₂ power cycles to be completed by 2030 (IEA, 2014).

In 2016, NREL and Sandia National Laboratories prepared a CSP Gen3 Roadmap to identify research and development gaps for the next generation CSP plant technology. All three technology pathways considered in the Roadmap are based on the sCO₂ power cycle. The Roadmap uses the 2020 SunShot targets as a reference, which set a power cycle efficiency of ≥50%, dry cooling with a heat sink at 40°C and power cycle installed costs incl. balance of plant of 900 USD/kW_e. Supercritical CO₂ power cycle efficiencies >50% require temperatures >700°C

and pressures >20 MPa and likely power block sizes >20 MW_e. Only the power tower solar field technology is considered to be capable of reaching these temperatures and unit sizes (Mehos et al., 2017, 2016).

Besides CSP, the sCO₂ power cycle technology is also intended for geothermal, coal and nuclear power production. Hence, the technology is developed outside the DOE SunShot initiative, by the US DOE's Supercritical Transformational Electric Power (STEP) initiative. In 2016, the US DOE committed US\$80M to build a 10 MW_e sCO₂ cycle pilot plant test facility to be completed by 2020. sCO₂ technology has been proven in a lab setting (US DOE, 2016). Efforts in the framework of the DOE SunShot initiative focus on the challenges of integrating the sCO₂ power cycle in CSP tower power plants, in particular of operating CSP tower receivers and thermal energy storage systems at temperatures $>700^{\circ}\text{C}$ (see also discussion about next-generation heat transfer media matching the temperatures of sCO₂ cycles in section 2.1.2). A significant effort is being invested in the US and elsewhere in the development of CO₂ turbines. The University of Queensland (ASTRI, 2018) is showing good progress on developing a unique, smaller (sub 5 MW) sized CO₂ turbine and CSIRO has two CO₂ turbine related projects (ARENA, 2014b, 2012a).

2.2.3. Hybridisation

The technical synergies between CSP approaches and fossil fuelled power generation lead to various hybrid approaches which are all being commercially developed:

- Combined heat and power applications
- solar input augmentation to existing fossil fuelled steam power plants ('solar booster');
- addition of gas fired back up and / or superheating for steam systems in stand-alone CSP plants; and
- incorporation of solar input to the steam cycle in a combined cycle power plant in a design known as '*Integrated Solar Combined Cycle (ISCC)*'.

An example of a CSP plant for combined power generation and district heating is the 16.6 MW_{th} Parabolic Trough system with Organic Rankine Cycle developed by Aalborg CSP in Brønderslev, Denmark. A solar booster was demonstrated in the Liddell Power coal power station (see section 5.1.3). Natural gas backup boilers are used for example in the SEGS power stations (instead of a thermal energy storage system). Global installed ISCC systems have a combined capacity of 157 MW_e. An example is the 75 MW Martin Next Generation Solar Energy Center in Indiantown, Florida (Alqahtani and Patiño-Echeverri, 2016).

Hybrid CST-photovoltaic (PV) systems aim to collect and utilise the waste heat (~60-80% of the incoming solar energy) that is rejected by PV cells through an active cell cooling system.

PV/thermal systems can utilise up to around 80% of the collected solar energy as a combination of power and heat. In concentrating PV/thermal systems, solar radiation is focused on a 100 to 1000 times smaller cell area, allowing the use of more efficient (and costly) multi-junction PV cells. Operation of multi-junction PV cells is limited to $\sim 100^{\circ}\text{C}$ due to material and efficiency

constraints. Higher temperatures can be achieved if the solar spectrum is split with a beam-splitting mirror into two portions. The high-energy portion of the spectrum is directed to the PV cell to generate electricity, while the low energy portion is directed onto a thermal receiver to generate heat. In this arrangement, higher output temperatures can be achieved. An example of a PV/thermal system is the RayGen tower system.

Hybridisation can also be applied in industrial processes by introducing solar thermal energy into normally natural gas-driven processes. For example, a current ARENA-funded project lead by the University of Adelaide is looking into pathways to integrate solar thermal energy into the Bayer alumina refining process (ARENA, 2016). Solar process heat can be introduced into the digestion process operating at around 200°C and into the calcination process operating at 700-800°C, to reduce the natural gas use.

2.3. Thermal Energy Storage

One of the identified key competitive advantages of CSP compared to PV or wind is the ability to build in low cost thermal storage for dispatchable operation.

As the percentage of intermittent / variable renewable energy capacity in a grid increases above certain thresholds, some level of short-term energy storage makes management of power quality less onerous. The inherent thermal inertia of CSP systems enables some smoothing of power outputs, even in systems without thermal storage. For example, for a typical Trough system, the 400°C heat transfer fluid in 1,000m of piping contains enough stored heat to run the system at maximum output for around three minutes.

Large amounts of high temperature thermal energy can be stored in more cost effective ways than electrical storage. Such storage systems typically use the HTF that passes through the CSP receiver as an integral part of their design.

The advantage of using thermal storage with CSP over electricity storage is that it is part of an integrated system that has improved output but with only a modest increase in installed cost and in many cases reduced cost of energy. A CSP plant without storage typically has a solar field that is oversized for its power block (to enhance the utilisation of the power block during off-peak solar irradiation). This means that at times of highest solar input it must take some mirrors off sun and so waste potentially collected energy. Adding thermal storage allows this energy to be captured and stored for later use. Furthermore, a storage system also allows the capture of intermittent solar energy periods that are too short to turn on a turbine to immediately use it.

In contrast, adding electricity in / electricity out storage, such as a battery, to a variable generator always adds significant capital cost and reduces the output energy available due to its internal energy losses.

Through the integration of a thermal energy storage system, CSP plant configurations can be optimised for peaking, shoulder or baseload power generation via the relative sizing of solar collectors, thermal storage and generation unit (power block).

The thermal storage system is typically located between the collectors and the power block. This allows the power block to be sized in an optimal manner relative to the solar field.

For example, for a given solar field size a storage system allows the power block to be down-sized and run at a higher capacity factor and closer to full-load. This results in capital cost savings in the power block and balance of plant and efficiency improvements which help to offset the cost of the storage components.

Alternatively, the storage system can be used to shift electricity generation to hours of the day when it is most valuable. In contrast, a CSP plant without thermal storage, can only generate power while the sun is shining.

In summary, thermal storage systems can improve CSP systems in terms of their flexibility, efficiency, cost of generated energy and annual energy collection.

The technology for thermal storage that is most advanced commercially is two tank molten salt, illustrated in Figure 1. The first commercial power plant to implement this approach was the 50 MW_e Andasol-1 Trough system in Spain. It commenced operation at the end of 2008 and has enough storage (1,010 MWh_{th}) to run for 7.5 hours at full 50 MW_e capacity or longer at part load. It achieves this using two tanks of molten nitrate salt⁵. The 28,500 tonnes of salt always remain molten (liquid) and cycle between a 'cold' tank at 292°C and a 'hot' tank at 386°C.

The Andasol-1 plant has been followed by a series of other commercial Trough plants using molten salt storage. The Solana 280 MW Trough plant in California with 6 hours of storage is currently the world's biggest solar plant with storage and has been operating successfully since 2013. During that time it has generated electricity at partial load for continuous 24 hour periods.

Tower systems currently have two major advantages in their implementation of molten salt energy storage compared to Trough plants. The higher achieved temperatures result in a bigger temperature difference between cold and hot tank, which means that nearly three times as much energy is stored for the same investment in tanks and salt material. Secondly, the ability to directly heat the salt in the receivers, which saves on the need for investments in a separate heat transfer fluid loop and heat exchangers. As a result, Central Receiver/Tower plants make more cost effective use of molten salt based thermal energy storage than Trough systems. However pilot systems for direct heating of salt in both Trough and Fresnel systems have been demonstrated and if properly established, will allow those technologies to overcome their existing disadvantages.

⁵ The salt composition is 60% NaNO₃ + 40% KNO₃

In 2011 the Gemasolar 19 MW_e Tower plant with 15 hours storage was commissioned near Seville (Figure 13). It is the highest capacity factor solar plant of any kind built to date and has over six years of successful operation including extended periods of full generation 24 hours per day. In 2015, the 110 MW_e Crescent Dunes Tower system in Nevada was built with 10 hours of full-load storage capacity, which is currently the biggest tower plant with storage. This system has suffered from some unanticipated issues with its hot salt tank leaking during the early stages of operation, however it appears now to be on track to reliable operation. These Tower systems employ the same salt as Trough plants but are able to heat it to higher temperatures (around 565°C).

The Atacama 1 110 MW_e Tower plant with 17.5 hours storage in Chile will be the biggest tower plant with storage when its construction is completed (expected for completion in 2019). It will be able to deliver baseload power round the clock. The Atacama 1 project has the further distinction of being directly competitive with conventional generation, due to a combination of factors - the outstanding solar resource, the cost reductions that CSP has experienced, and the high cost of imported gas in Chile.



Figure 13: 19MW Gemasolar tower plant in Spain.

A significant cost saving development for molten salt storage which is progressing well is the use of a single tank, with a thermocline⁶.

Direct storage of high temperature water / steam in insulated pressure vessels is also well established however only judged economically feasible for storage capacities of around 1 hour or less.

Other approaches to energy storage at various stages of research, development and deployment (RD&D) include: solids such as graphite, concrete and particles (ceramic or silica), reversible chemical reactions and high temperature phase change materials.

⁶ In such a system, hot salt is stored above cold salt in one tank, with a moving transition zone in between.

Examples include an alternative approach taken by Australian based company Solastor. Their 24-m high modular tower system holds a 10-ton graphite storage block at the top of the tower, directly heated by the solar radiation. The heat is extracted on-demand via steam lines running through the graphite block, transferring superheated steam to the steam turbine power cycle.

Italian industrial company Magaldi offers a modular central receiver system with beam-down optics, to avoid the need for a tower to mount the receiver. The receiver contains a fluidised bed of sand that is heated and stores thermal energy at 650 to 750°C. Steam lines running through the sand bed collect the thermal energy for power or industrial process heat uses.

The Australian National University's Solar Thermal Group has developed an ammonia-based thermal energy storage, particularly targeted at solar dish collectors. Ammonia is dissociated in the solar receiver at 700°C. The resulting hydrogen and nitrogen gas mixture is stored under pressure and recombined, releasing heat at around 500°C to produce steam for a steam turbine power plant. This has been further progressed by the University of California Los Angeles (UCLA) working in partnership with ITP (Lavine et al., 2016).

Overall, 44% of existing CSP power plants and the majority of new projects employ thermal energy storage, typically with at least 4 hours of full-load capacity and up to 17.5 hours.

3. GLOBAL STATUS

Globally, after an initial start in the late 1980s followed by some years of hiatus, CSP has been growing strongly since around 2006. However, CSP's deployed generation capacity is only about 2% of the global PV industry but with a global trajectory that matches that of PV's growth about a decade earlier.

3.1. Installed Capacity

There are many sources of information that can be monitored to track construction progress of CSP projects. It should be noted in reading listings of announced projects that, historically, only about a third of those announced have actually achieved financial closure and been constructed.

The IEA Solar Power and Chemical Energy Systems (SolarPACES) program is the umbrella under which the CSP community has worked together and shared information for many years. The SolarPACES website (SolarPaces, 2018) has good overview information and a link to a project listing hosted by NREL. However, the status of projects can date quickly, so that a project noted as under construction could actually have commenced generation. An overview of CSP project volume by region in terms of installed capacity is shown in Figure 14, broken down into projects that are operational, under construction, or under development.

The deployment of utility scale plants began in the US in the mid 1980's. With changes in policy in the US the global growth in CSP stopped for over 15 years before a major initiative in Spain saw that country take the lead. Subsequently Spain also saw a change of political direction and other countries have since played a larger role.

At the end of 2017, global installed and operational net (nameplate) CSP power generation capacity was around 5.1 GW_e as shown in Figure 15. While the US and Spain are where most of the early development occurred, in the last few years first CSP plants have also been completed in Morocco, South Africa, India and UAE. Several additional countries have multi-megawatt projects under construction or under development, including China, Chile, Morocco, Israel and Saudi Arabia.

The 5.1 GW_e of installed capacity is made up of 64 plants with size 50 MW_e or larger constituting over 90% of the installed capacity, with the remainder comprised of about 32 smaller pilot type projects. All the large plants continue to operate on a commercial basis according to the various offtake arrangements in the countries concerned. Exceptions are the earliest SEGS I and II plants built in the mid-1980s which are currently non-operational.

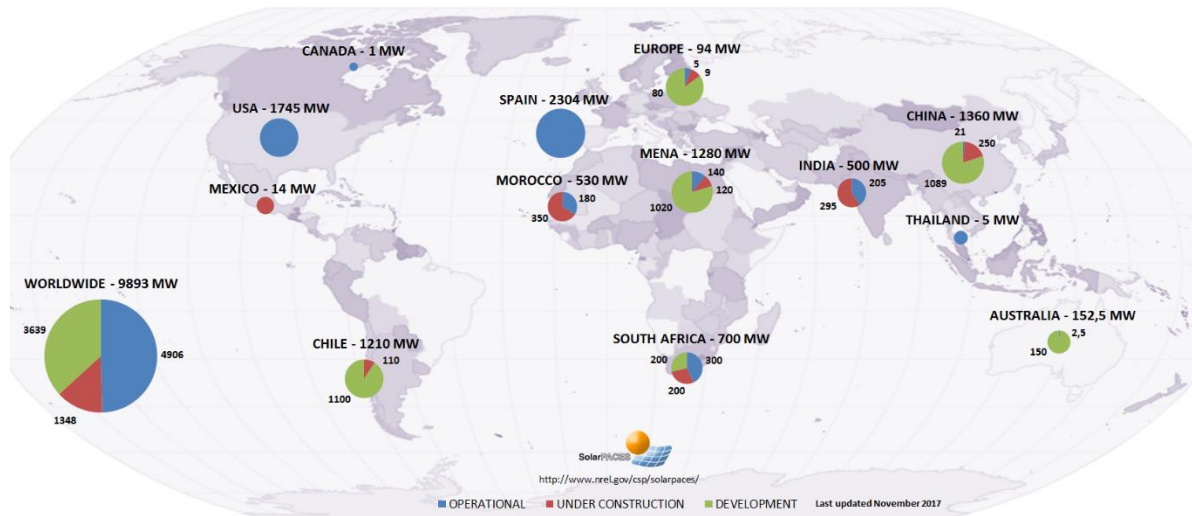


Figure 14: Overview of CSP project volumes by region in terms of installed capacity, divided by status (blue is actual installed and operational capacity; source: Solarpaces).

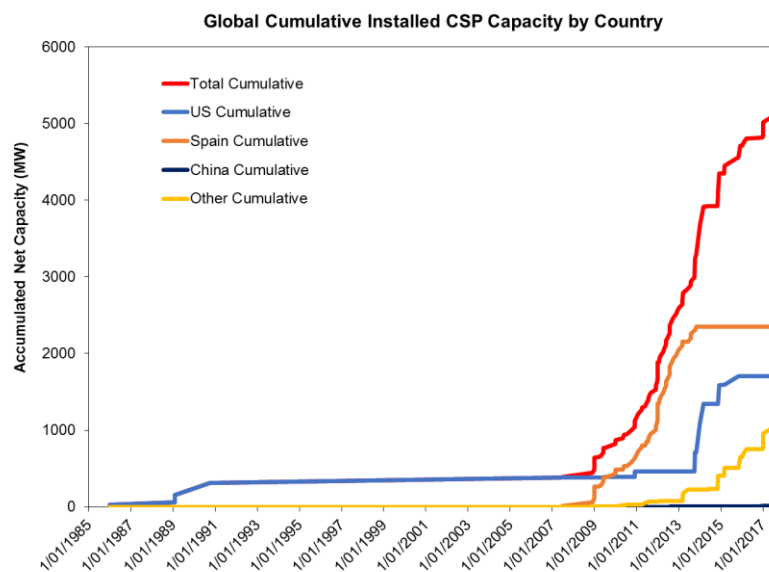


Figure 15: Growth in CSP installed capacity by country, (ITP; data: Solarpaces/NREL).

3.2. System reliability

Consistent electric energy generation year by year is a key requirement for CSP's commercial success, as it underlies any planning and financing step of a CSP plant. Several operational factors influence the performance of a CSP plant:

- year-to-year variation in solar energy availability
- frequency and duration of yearly inspection and maintenance (scheduled down time)

- unplanned down-times or reduction in power output due to technical defects
- reduction in solar energy collection due to soiling (reversible) and degradation (irreversible) of mirrors or receivers over time

The long-term operational performance of existing CSP plants provides a data base to assess the reliability of CST technologies.

3.2.1. Parabolic trough

Nearly all of the CST plants by capacity installed between the mid-1980's until 2013 use parabolic trough technology. This technology has a track record starting with the SEGS plants in the mid-1980s, with a global cumulative installed capacity of 4.3 GW as of 2017. All but the first two of the nine SEGS plants built in California between 1985 and 1990 continue to operate today. As can be seen from Figure 16, the SEGS III to IX plants have performed reliably every year from 2001 to 2017. They also show a correlated year to year variation that is presumably linked to the varying solar input. Since 2013 there has been a trend to decline which may be the result of aging collectors over the course of 3 decades of continuous operation. Nevertheless, the plants continue to operate, well past their life expectancy of 25-30 years.

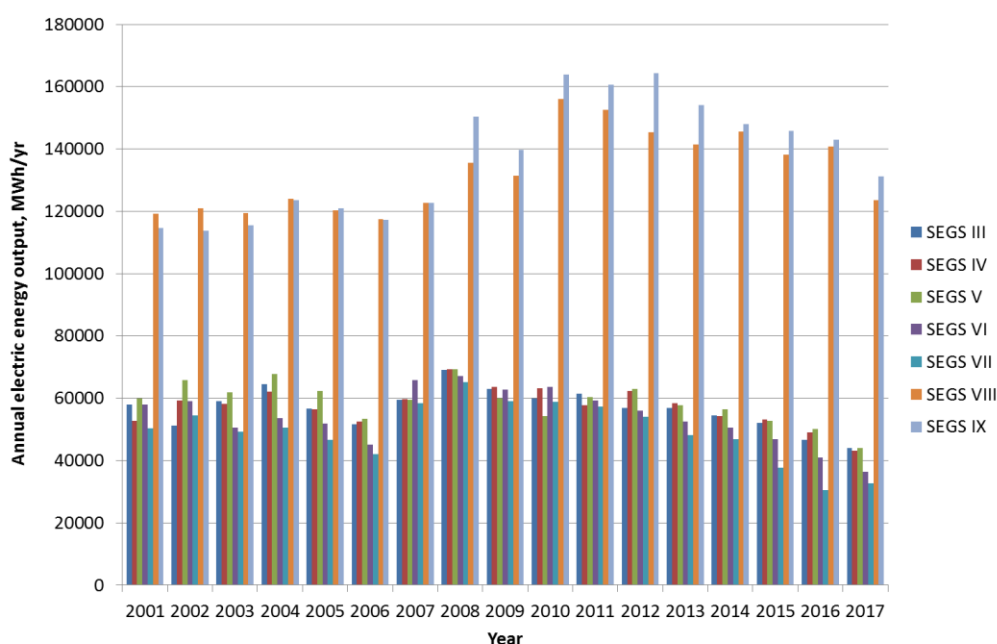


Figure 16: Annual solar electric energy output of the SEGS III to IX power plants from 2000 to 2016 (data: EIA).

Reliable operation can also be observed for the 72 MW Nevada Solar One and the 280 MW Solana (AZ) parabolic trough plants, both of which have operated at a stable output since their commissioning in 2007 and 2013 respectively (Figure 17, top). The Nevada Solar One plant has been fully operational since 2008 and has since performed at a stable level within 20% of its

projected design output, year after year. The Solana plant started full operation in 2014 and has delivered stable output of 600,000 to 725,000 MWh/yr and appears to be approaching its design annual output of 944,000 MWh/yr (NREL). Fires in two of the plant's transformers have been reported that have caused a reduction in the power output in July and August 2017.

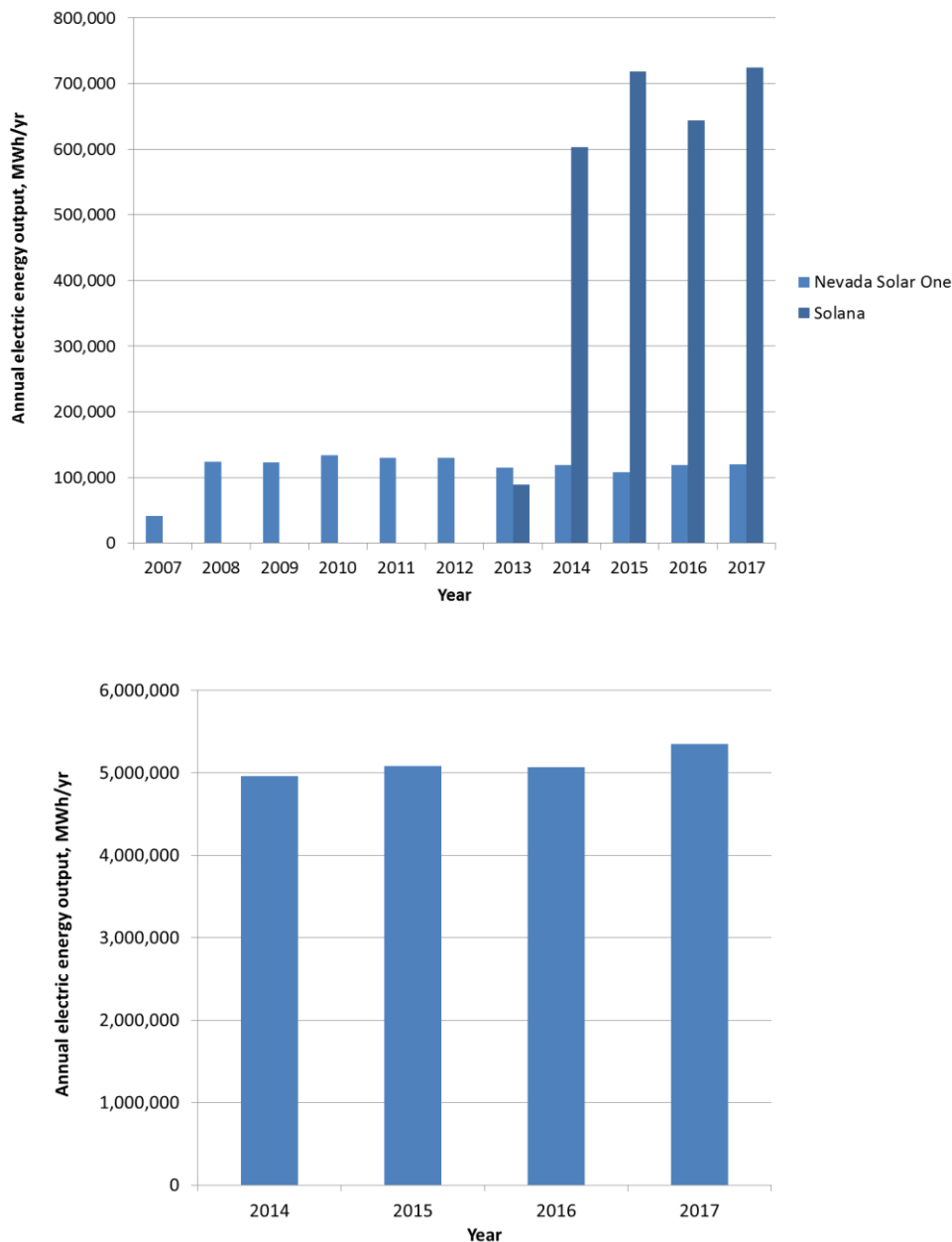


Figure 17: Annual solar electric energy output of Nevada and Solana plants in the US (top) and of Spanish fleet of CST plants (bottom) (data: REE; EIA).

Nearly all (97% by capacity) of the 50 CST plants built in Spain between 2007 and 2013 with a cumulative capacity of 2.3 GW are parabolic trough plants. These plants have a very consistent

operational performance record since their completion, close to their estimated design annual power output each year, with an upward trend in performance observable since their completion in 2014 (Figure 17, bottom).

In sum, parabolic trough plants have demonstrated very dependable and stable long-term performance year-by-year over more than 30 years.

3.2.2. Power Tower

Solar tower technology has had a much shorter demonstration period at the commercial scale than trough technology. The first utility-scale tower plants (PS10 and PS20) were direct steam generating plants built in 2007 and 2009, respectively. Table 2 provides a list of the largest solar tower plants in the world completed to date.

Table 2. Overview of operating large-scale solar tower plants.

Name	Year of completion	Country	Capacity, MW	Storage, hours	Heat transfer fluid	Company
Planta Solar (PS) 10	2007	Spain	11	1	water/steam	Abengoa
Planta Solar (PS) 20	2009	Spain	20	1	water/steam	Abengoa
Gemasolar	2011	Spain	19.9	15	molten salt	SENER/Torresol
Ivanpah 1-3	2013	USA	440	0	water/steam	Brightsource
Crescent Dunes	2013	USA	110	10	molten salt	Solar Reserve
Khi Solar One	2016	South Africa	50	2	water/steam	Abengoa

Both the steam-based PS10 and PS20 plants and the molten-salt based Gemasolar plant have been reported to operate reliably since their completion. As shown in Figure 18 (top), the Ivanpah 1-3 plants, using direct steam generation technology, have also demonstrated stable and increasing annual energy output since their start in 2014. Its annual output is however currently still about 1/3 below the expected design output reported by NREL.

The molten salt-based Crescent Dunes plant, which was planned to be fully operational in 2016, is currently experiencing delays for technical reasons (Figure 18 (bottom)). However, due to complexity of the technology and the large size of the plant, longer commissioning phase is to be expected and a conclusion about this plant's long-term operational performance cannot be drawn yet at this stage.

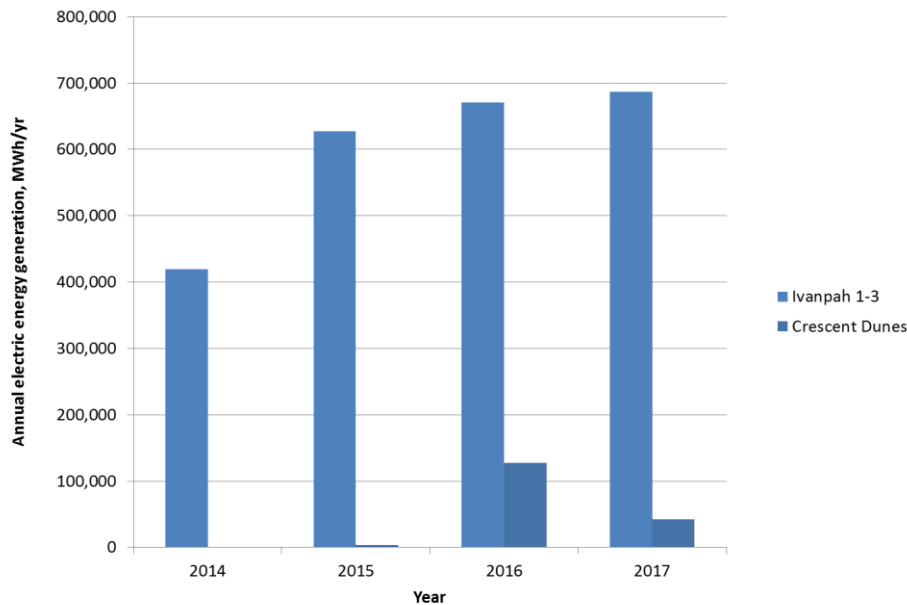


Figure 18: Annual solar electric energy output of Ivanpah 1-3 (top) and Crescent Dunes (bottom) molten-salt solar tower plants (data: EIA).

In conclusion, plants of the more recently commercialised solar tower technology have been successfully designed and built and have operated at a stable annual output for several years. The recent large-scale US-based Ivanpah and Crescent Dunes plants have not yet met their full performance potential and it remains to be seen to what extent these plants will live up to their expectations. Nevertheless, the operational performance of the first tower plants is very promising and the technology overall promises substantially lower energy costs than parabolic trough in the medium- to long-term, due to its potential to reach much higher thermal efficiencies and lower thermal storage costs.

3.3. Key commercial players

Trying to track the key commercial players in the CSP value chain globally is a difficult task as companies have entered and left, merged or changed names at various times. There are players who have made a mark globally and then in every country a range of smaller companies making local contributions.

The contributions can be categorised as

- Project developers – companies that select a site and put together financing, offtake and choice of partners to execute, with the EPC contractor the prime execution partner
- Engineer, procure contract (EPC) contractors – who are the core players in making sure a project is built and works as specified

- CSP technology developers – companies that have developed and tested proprietary concentrator systems and then offer them for use in projects.
- Component suppliers – companies who manufacture or supply all the parts and subsystems. Sometimes concentrator specific components (e.g. glass mirrors), sometimes more generic components (e.g. pumps, piping and civil engineering services)
- Service providers – consultants and engineering service providers who contribute to feasibility studies, testing or owners or lenders engineer roles

In addition to these there are financiers, government agencies, research organisations and industry associations all acting as stakeholders in the industry.

Understanding the players is further complicated by the history of the industry where many of the key players have appeared in more than one role.

Table 3 to Table 6 present non-exhaustive lists that attempt to capture the major CSP project players globally ordered from highest levels of experience downward, together with known Australian players. It should be noted that every country with potential for a CSP industry, will also have a range of smaller companies who are not yet active outside their own country and are hence not listed in these tables.

The list of developers includes Engie of France together with three large Japanese corporations who have flagged interest in CSP but have no prior experience. In this regard it can be observed that a large corporation with a background in developing other large power or industrial projects can step into CSP relatively easily as a developer if it chooses its EPC and suppliers carefully. Start up companies promoting their own technologies tend to serve as project developers also and Vast Solar and Solastor from Australia are listed in this regard. Also listed from Australia is CWP, a successful wind farm developer that has expressed an interest in a CSP project for Queensland.

The list of EPC companies includes players who also act as EPC for their systems based on their own technologies. A large corporation with a body of EPC experience in the power sector can take on a first large CSP project if it uses suitably experienced subcontractors. John Holland in Australia falls in such a category and successfully drove the Sundrop farms project. Shanghai Electric from China are notable for having just won the EPC contract with developer ACWA for the high profile 700MW system for Dubai. This will be a very major initiative also notable for the very low cost tariff that was bid to win it.

Trough and Tower technology providers are listed separately in Table 5 and Table 6. In each case the Australian companies that are involved are listed. It can be seen that their experience is very small compared to global players. In fact every country with potential for CSP uptake has multiple small companies attempting to promote their own technologies. Very few are known outside their own countries. The key metric for success by new entrants appears to be the level of initial investment they are founded with rather than the novelty of their ideas.

Table 3. Overview of CSP project developer companies.

Company Name	Country of origin	Estimated number of employees	Approx sum of Experience (MWe)
SENER	Spain	2000	2000
Abengoa	Spain	13000	1400
Aries	Spain	150	650
Cobra	Spain	30000	630
Acwa Power	Saudi Arabia	3000	610
Bright Source	USA	300	500
TSK Flagsol	Spain	850	500
Acciona Energy	Spain	2800	314
SAETA Yield	Spain	40	250
Orascom Construction	Egypt	53000	150
Masdar	UAE	261	120
Ibereolica	Spain	50	100
Solar Reserve	USA	200	100
Duro Felguera	Spain	2000	50
Godavari green energy	India	6000	50
Megha green energy	India	700	50
Torresol Energy	Spain	100	20
Tecnicas Reunidas	Spain	9000	11
Cargo Power & Infrastructure	India	102	10
Suncan	China		10
Aalborg CSP	Denmark	56	5
Solastor	Australia	5	3.5
Enel Group	Italy	3609	1.5
Kraftanlagen München	Germany	2300	1.5
Vast solar	Australia	12	1
Chiyoda Corporation	Japan	6097	0
Engie	France	150000	0
Marubeni	Japan	40000	0
Mitsui	Japan	6000	0
Sumitomo	Japan	75000	0
CWP	Australia	50	0

Table 4. CSP EPC companies.

Company Name	Country of origin	Technology	Estimated number of employees	Approx sum of Experience (MW _e)
SENER	Spain	Trough and tower	2000	2000
Abengoa	Spain	Trough and tower	13000	1200
Cobra	Spain	Trough and tower	30000	630
Acciona	Spain	Parabolic Trough	30000	628
TSK Flagsol	Spain	Parabolic Trough	850	500
Bright Source	USA	Power Tower	300	500
Bechtel	USA	Power Tower	53000	400
Orascom Construction	Egypt	Parabolic Trough	53000	150
Duro Felguera	Spain	Parabolic Trough	2000	50
Tecnicas Reunidas	Spain	Trough and tower	9000	11
SEPCO III	China	Power Tower	20000	10
Suncan	China	Power Tower	100	10
Sky Fuel	USA	Parabolic Trough	50	10
John Holland	Australia	Power Tower	5000	1.5
Shanghai Electric	China	Tower and trough	?	0

Table 5. Trough providers.

Company Name	Country	Estimated number of employees	Approx sum of Experience (MW _e)
SENER	Spain	2000	2000
Abengoa	Spain	13000	1000
Acciona	Spain	30000	628
TSK Flagsol	Spain	850	500
Aalborg CSP	Denmark	56	85
Sky Fuel	USA	50	10
Glass Point	USA	300	7
Solarlite	Germany	30	5
Royal Tech CSP	China	100	3
Solitem	Germany	7	1
NEP Solar	Australia	2	0.1

Table 6. Tower providers.

Company Name	Country of origin	Estimated number of employees	Approx sum of Experience (MW _e)
Bright Source	USA	300	450
Abengoa	Spain	13000	200
SENER	Spain	2000	120
Solar Reserve	USA	200	100
Suncan	China		10
Solastor	Australia	25	3
Vast Solar	Australia	25	1
Heliostat SA	Australia	10	0.1

3.4. Key countries

The following sections summarise the progress and status of CSP in each of the main regions. Further country-specific information can be found on the SolarPaces website (SolarPaces, 2018).

3.4.1. Spain

The renewable energy policy adopted in Spain in 2007 established a Feed-In-Tariff of 0.27€/kWh⁷ for CSP over 25 years for plants of up to 50 MW_e in capacity. This enabled the rapid development of a leading CSP industry in a short period of time. By 2013 a total of 2.3 GW of CSP were installed (Figure 19), employing a workforce of approximately 20,000 professionals (Protermosolar, 2017). However between 2012 and 2013 several royal decrees reversed the policy and limited the development of new CSP plants and brought the market to a complete standstill.

Despite the adverse policies, Spain nowadays still remains as the international CSP leader for accumulated deployment representing nearly half the global capacity with 2,300 MW. Currently there are a total of 50 plants under operation, 96.2% of the plants use Parabolic Trough technology, 2.5% Power Towers and 1.3% linear Fresnel technology (NREL, 2017a). Approximately 40% of the plants have in-built molten salt thermal storage. CSP plants cover 0.6% of the energy demand in Spain and employ a total of 5,200 professionals (Protermosolar, 2017).

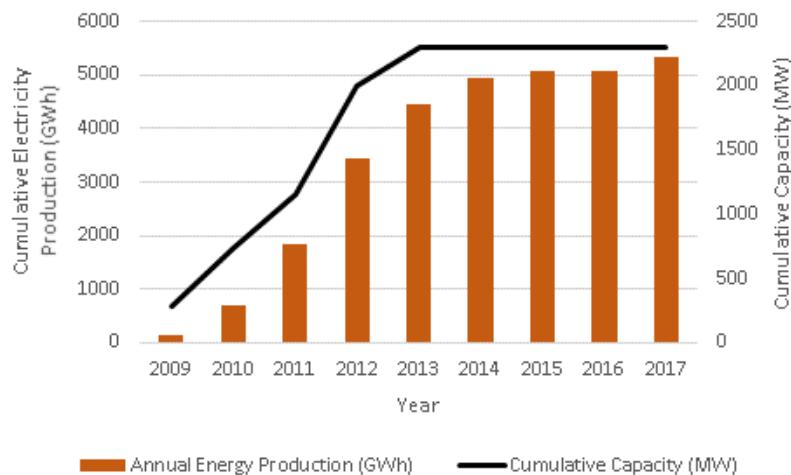


Figure 19: CSP Capacity and Energy evolution in Spain (IDAE, 2017; Protermosolar, 2017).

The prospects and current outlook for CSP in Spain are presently not very optimistic as a consequence of the retroactive policy changes between 2012 and 2013 that cancelled the feed in tariff for existing plants retrospectively and replacing it with a reduced level of income with a consequent negative impact on investors' confidence in future projects.

⁷ equivalent to ≈0.43AUD/kWh; compare to average wholesale price in Australia 2017: 0.085AUD/kWh; (AEMO)

In June 2018, the Spanish solar thermal association, Protermosolar, presented their plan for the Spanish electricity mix for year 2030 (Protermosolar, 2018). The plan suggests a combined share in installed capacity of renewables of 86%, including wind, PV, CSP, hydro and pumped-hydro energy, totalling 106 GW of capacity, with the remaining 14% covered by combined cycle gas power plants and co-generation, while nuclear and coal power are eliminated from the mix. A key to reaching this high renewable energy penetration is a growth in CSP capacity to 20 GW with 15 hours of thermal storage and capping of PV capacity at 25 GW.

The report was a response to a report prepared by an expert panel of the Spanish government which maintained coal and nuclear power and suggested a growth in gas power rather than renewables. The plan presented by Protermosolar reduces the level of curtailment of wind and PV from 4,600 to 830 GWh compared to the plan of the expert panel, due to the reduction in PV and increase in CSP capacity with thermal storage. In addition, since Spain is home to leading CSP technology companies, the plan of Protermosolar would add an estimated €65bn to the Spanish economy.

3.4.2. USA

The USA pioneered the CSP industry with the world's first SEGS plants in the late 80's. These plants were enabled by policy measures including state-based renewable portfolio standards, federal tax credits (currently 30%) and federal loan guarantees. As incentives ceased in the early 90's, CSP developments came to a standstill and didn't resume until the construction of the Nevada Solar One plant, which completed construction in 2007.

In 2011 the American Recovery & Reinvestment Act (ARRA) was approved with the aim to support with \$6 billion in loan guarantees for renewable energy projects that included CSP technologies. The DOE Loan Guarantee Programme guaranteed projects that started by September 2011.

Furthermore the implementation of economic instruments such as the Modified Accelerated Cost Recovery System (MACRS) allowed solar installations to be depreciated over a period of 6 years. This accelerates the return on investment and reduces the tax liability in the first years of the plant operation increasing the attractiveness for private investors. The California Energy Commission and the Public Utilities Commission adopted as well the Time-of-Delivery (TOD) factors to estimate the electricity market price. The TOD factors take into account the varying energy and capacity values of electricity delivered in different times of the day and are used to evaluate different generation profiles on a comparable basis. The dispatchability of CSP plants allows them to benefit from the TOD factors.

The combination of the different schemes and instruments allowed the growth of renewable energy and the CSP market in the US. As a result of these measures USA represents the second largest market in terms of total installed capacity with 1,745MW. In 2014 the Ivanpah Solar Power Facility a 392 MW power tower plant was completed representing the world's largest CSP facility.

Furthermore since 2014 the world's biggest parabolic trough plant Solana is under operation with a capacity of 280 MW. There are other parabolic trough plants that are operational since 2014; the Mojave Solar Project and the Genesis Solar with capacities of 280MW and 250MW respectively. The most recently completed plant in the USA, is the high profile Crescent Dunes 100MW_e molten salt tower system in Nevada.

3.4.3. South Africa

South Africa promulgated the “Integrated Resource Plan (IRP) 2010-30” in 2011. The plan introduces a set of ambitious generation targets for renewable energy market penetration by 2030, with wind and solar expected to be represent most of the future renewable electricity mix. The primary target is to reduce the share of coal in the total installed capacity. According to the plan by 2030, South Africa will install CSP capacity of 1,200 MW (IEA, 2018a) and has already installed 300 MW of CSP plants which are operational.

In 2013 under the REIPPPP program a “multiplier” factor was introduced in the CSP capacity auction. The multiplier applied for all the electricity generated between 16:30 and 21:30 where the remuneration was increased by a factor of 2.7. As occurred in California with the TOD factors CSP plants were rewarded for their ability to be dispatch capacity during peak demand hours while the sun was already starting to set.

The Northern Cape has been identified as an area with an exceptionally high solar irradiance of about 2800 kWh/m²/year, A series of large scale CSP plants are under development and construction in recent years. These comprise the Bokpoort, Kaxu and Xina parabolic trough systems, all with molten salt energy storage, plus the Khi Solar One tower project. The Khi tower project by Abengoa uses 4 separate direct steam receivers arranged around the tower. It has 2 hours of storage capability using compressed hot water and has trialled a novel approach to cooling whereby the tower itself is used as a natural draft cooling tower. The planned Redstone 100MW molten salt tower project is intended to be similar to the Crescent Dunes system built by SolarReserve. It and others had been delayed by the government's failure to execute a PPA agreement that was initially awarded under the auction process. This has recently been rectified following the change of president.

3.4.4. Morocco

Morocco has announced plans to develop 2000 MW of solar energy projects both PV and CSP, across five different sites (World Future Council, 2015). The process is run by the Moroccan Agency for Solar Energy (MASEN) and central to it is the establishment of major solar park precincts. The biggest project so far is the Noor Project and it comprises 3 stages; Noor I, Noor II and Noor III. The complex is located near Ouarzazate city which is at the edge of the Sahara desert and has DNI is > 2600kWh/year⁸ When complete the Noor complex will have a total

⁸ Equivalent to Alice Springs in Australia for example.

capacity of 510 MW CSP projects (HeliosCSP, 2018). The first project Noor I is a 160 trough plant with 3 hours storage was commissioned in 2015 and Noor II, a 200MW trough plant with 7 hours storage and Noor III a 150MW molten salt tower system with 7 hours storage are well progressed in construction / commissioning. Construction of the individual systems has been awarded by competitive tender against the specific project specifications.

Morocco's implementation in CSP began with a 20MW trough based Integrated Solar Combined Cycle project that has been operational at Ain Beni Mathar since 2008.

Morocco already has a small undersea cable to Spain. As well as their own plans for 50% RE by 2030, supply of green electricity to Europe via Spain is very plausible.

3.4.5. Chile

The northern part of Chile comprises the Attacama desert. This area has the highest annual average DNI levels on the planet. It also has significant mining activity and little in the way of centralised electricity generation relative to overall demand. There is a pipeline of 9 projects in the planning phase.

Currently there is a single plant under construction in Antofagasta "Planta Solar Cerro Dominador (Atacama 1)" (NREL, 2018). The unit has a gross capacity of 110MW with a 17.5hours of storage. The project developer and EPC, Abengoa, ran into financial difficulties in 2017 stopping the work at a point of about 50% construction. However the project consortium has been renegotiated and construction has been restarted and plant is expected to start production in 2019.

The Chilean Ministry of Energy has developed a Chile CSP roadmap that includes plans to establish a 1 GW solar park that is intended to include 6 x 100MW_e tower systems.

3.4.6. China

China has a target of 50% Renewable Electricity generation by 2050 which can be compared with a level of 11% in 2015. PV and wind deployment is already very large in the country. The best wind and solar resources are on the western and northern provinces on the other hand most of the population is to the East. A consequence of this is that due to transmission limitations from west to east, approximately 20% of the potential wind generation is already lost due to curtailment. In this context, China announced a FIT of 1.15RMB/kWh for a "pilot program" of solar thermal projects in 2017 and approved a total of 20 Projects with a total capacity of 1.35GW. There is officially a deadline of 2018 for these projects to complete commissioning if they are to retain the FIT offer. The projects include tower, trough and LFR and most incorporate storage.

As at the end of 2017, 3 projects had progressed significantly (12-50%) in construction; Delingha 50MW trough, Delingha 50MW molten salt tower and Shouhang Dunhuang 100MW salt tower. A further 5 projects are reasonably progressed with a good chance of ultimately being completed.

The others appear unlikely to proceed at present. Of the 7 that appear to be progressing, it seems likely that most will need to negotiate a deadline extension.

Beyond this initial pilot program China has suggested longer term plans for around 30GW of CSP by 2030.

3.4.7. India

India announced its ambitious National Solar Mission (NSM) in 2010 and under the Phase I part of the mission a total of 470 MW of CSP plants were awarded to 7 developers. The developers were selected through a reverse auction mechanism in which each bidder had to bid their best price against MNRE's benchmark price (15.31 Rs per kWh). The bidding process was very competitive as there were 55 bidders and it brought down the offered offtake price for CSP electricity beyond expectations. However many of the aggressive bidders who won an allocation proved not to be viable and have not proceeded. These were local developers without prior experience in the industry who were not aware of the challenges associated with constructing and operating CSP plants. There are now three complete plants. The Godawari 50MW trough system appears to be most successful with publically available generation data. The Megha 50MW trough system and the Dhursar 125MW Fresnel systems are complete but so far no confirmed performance data has been made public. The Abhijeet 50MW trough plant began initial construction but has been stalled for some time largely as a result of unrelated legal and financial issues in the project developer company.

Under state based schemes, the Gujarat Solar 1 25MW trough plant with 9 hours storage and the Dadri 14MWth ISSC system using Fresnel are known to be under construction.

As per a recent CERC record of proceedings (Record of Proceedings (ROP) in Petition No. 327/MP/2013 & other related petitions) it seems that the major issue affecting the deployment of most of the NSM projects was unreliable ground measured DNI data which was published by the Ministry of New and Renewable Energy. This published data formed the basis for framing of the NSM policy, the tariff and the capital outlay for CSP projects in India. DNI published by MNRE for some of the best sites (Rajasthan) in India was >2000 kWh/m²/annum. This is very high when compared to the actual ground measured DNI received recently which was only 1763 kWh/m²/annum. This will affect the size of the solar field thus the estimated project cost and questions the benchmark tariff suggested by CERC. The above issue is being raised with CERC by the developers and was currently under review as of Aug 2017.

3.4.8. Other Middle East North Africa

Algeria

Algeria has a 20MW trough based ISCC plant that has been operating since 2011. Algeria launched its energy efficiency and renewable energy program in 2011 to deploy 22 GW of

renewable energy capacity by 2030. The Plan forecasts that solar electricity production will increase up to 37% of total national electricity production by 2030. The legal basis for the tendering document has been released in March 2017 and the country is expected to deploy 2000 MW of solar thermal power plants (IEA, 2018b).

Israel

The Israeli government allocated quotas for production of electricity from renewable energies at 2,280 MW to be installed by 2020. Approximately 58% of the quota are for solar technologies and 180 MW is allotted for solar thermal power technologies. Currently two projects are under construction in the Negev desert near the kibbutz of Ashalim (HeliosCSP, 2012): a 110 MW trough system with 4.5 hours of storage and a 121 MW direct steam tower system without storage. The Megalim power station already being deployed would be in addition to the 180 MW planned capacity.

Kuwait

Kuwait presented the Shagaya initiative in 2011, which is to build 2,000 MW of renewable energy power plants by 2030. CSP is planned to contribute to 1,150 MW of the total capacity and the rest will be by Wind and Solar PV technologies (IEA, 2009). The first 50 MW CSP project is already under construction and expected to be completed by 2018.

Saudi Arabia

Saudi Arabia launched its National Renewable Energy Program (NREP) recently. The program is an initiative that aims to substantially increase the share of renewable energy capacity in the total energy mix within the Kingdom to 9.5 GW by 2023. The main drive behind the policy is to lower the rising domestic oil consumption for power and to preserve it for exports. There are currently two ISCC plants under construction, the 43 MW Duba 1 and 50 MW Waad Al Shamal.

Oman

A combination of concentrated solar power and photovoltaic technologies are likely to be deployed for the development in Dakhiliyah Governorate which is one of the largest solar energy projects in Oman's National Energy Strategy 2040 with a plant capacity of 200 MW (Kaleem, 2017). In addition Oman is planning to heavily invest in solar thermal technology along with oil major Shell and Glasspoint Solar to boost oil production. There is already a 7 MW pilot plant operational in Amal, Oman (Petroleum Development Oman, 2017) configured to produce steam for injection for Enhanced Oil recovery. Glasspoint Solar along with Shell and Total have plans to construct another 1021 MW_{th} of EOR system, the Miraah project (GlassPoint, 2018). This project will offset 80% of natural gas utilised in the oil fields for Enhanced Oil Recovery to export market (Chadha, 2014).

Tunisia

In 2009, the Tunisian government adopted the Tunisia Solar Plan to achieve 4.7 GW of renewable energy capacity by 2030 which includes the use of solar photovoltaic systems, solar water heating systems and solar concentrated power units (Zafar, 2017). TuNur Energie a private company is planning to build a CSP complex with a capacity of 2,000 MW. The project was named TuNur and is expected to export power between North Africa and Europe (Darby, 2017). So far there has been no active construction.

United Arab Emirates

Renewable energy has become economically attractive in the oil-rich United Arab Emirates (UAE). Ramping up renewables to 10% of the country's total energy mix, and 25% of total power generation, could generate annual savings of USD 1.9 billion by 2030 through avoidance of fossil-fuel consumption and lower energy costs (IRENA, 2015). Inaugurated in the UAE in 2013, 100 MW Shams is one of the largest CSP plants in the world. Recently DEWA selected Saudi Arabia's ACWA Power and China's Shanghai Power to build a 700 MW plant (600 MW Trough with 10 hours of storage and 100 MW Tower with 15 hours of storage) providing more than three times the capacity of the initial plans for the extension. ACWA Power's plant is expected to cost 3.9 billion USD. Under the terms of the contract, the new plant will deliver energy at 7.3 US cents per kWh which will make this a benchmark project in the world in terms of cost of generation. One reason for such low price is because of the involvement of China's Shanghai Electric in the project as DEWA's tender criteria did not enforce local content requirements. Shanghai Electric's involvement in the project will help drive down costs drastically. Shanghai Electric is currently building CSP capacity in China as part of the country's ambitious targets to complete 20 CSP projects of total capacity 1.3 GW by 2018.

Egypt

Egypt's Supreme Council of Energy announced an ambitious plan to generate 20% of the country's electricity from renewable sources by 2020, including a 2% contribution from solar energy, translating into 2,870 MW (Report presented by chairman of NREA and MoE&RE). Currently, there is one 20 MW Trough ISCC system in Kuraymat, 100 km south of Cairo, operational since 2011. Two additional plants, a 100 MW Trough system in Kom Ombo and a 250 MW Tower system approximately 200 km west of Cairo have been considered.

Jordan

Jordan has major plans for increasing the use of solar energy. The Government is hoping to construct the first Concentrated Solar Power (CSP) demonstration project in the short to medium term and is considering Aqaba and the south-eastern region for this purpose. It is also planning to have solar desalination plant. According to the national strategy the planned installed capacity will

amount to 300MW–600MW (CSP, PV and hybrid power plants) by 2020 (HeliosCSP, 2014). There are currently 5 specific CSP projects in the planning phase to a total capacity of 225MW_e.

Libya

The main goal of the Renewable Energy Authority of Libya (REAOL) is to implement proper policies so as to meet the governmental target of a 30% share of the total energy mix coming from renewable energy sources by 2030. REAOL developed a Long term Renewable Energy Development Plan from 2008 to 2030 in which it plans to develop 2100 MW of CSP plants in four stages (IEA, 2007).

4. SERVICES AND BENEFITS

Solar energy based generation in general offers the prospect of non-polluting sustainable electricity. Solar thermal generation with storage offers extra values beyond the baseline of variable renewable generation. The key differentiating concept is dispatchability, system operators are able to predict and indeed control the generation levels from a solar thermal plant within the constraints of its configuration in a way that cannot be done with variable renewables. CSP plants with extended hours (>10) of thermal storage are effectively baseload in their nature, on the other hand more agile plants with bigger power blocks relative to solar field and thermal storage can act more like traditional peaking plants.

4.1. Firm capacity

Some of the potential sources of value rely on the ability of a generation asset to provide ‘firm’ capacity. In simple terms this could be described as the extent to which a system can reproduce the utility of a conventional gas turbine plant. One way of measuring this is modelling operation through a year and evaluating the capacity factor average over just the highest peak load events experienced. As part of the network benefits study carried out by a team lead by UTS (Rutovitz et al., 2013), this was done across the Australian NEM, for a number of energy storage levels and times of the year. Indicative firm capacity was evaluated by considering the average capacity factor during the top 21 load events of the season using historic NEM data and a simplified CSP plant model with standard dispatch with hourly solar data based on BOM satellite based DNI data.

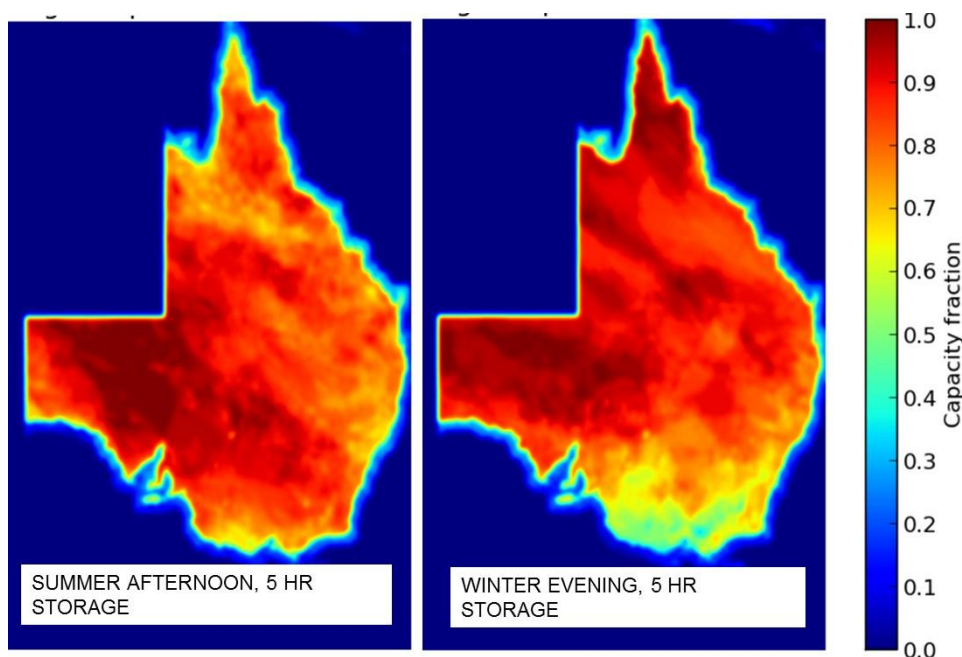


Figure 20: Indicative firm capacity of CSP plants across the eastern states.

Key results are indicated in Figure 20. It can be seen that with just five hours of storage capacity, very high indicative firm capacity values are obtained in many areas. This increases further with larger amounts of storage. Similar results would no doubt be found for WA and NT.

Studies of scenarios for 100% renewable electricity supply, typically find that due to these characteristics, significant portions of CSP capacity are an essential part of a mix capable of meeting demand at all times.

Figure 21 from the 2013 AEMO study on 100% RE scenarios shows how CSP with storage, hydro electricity and biomass are needed to fill in the gaps that result from variable renewables (AEMO, 2013).

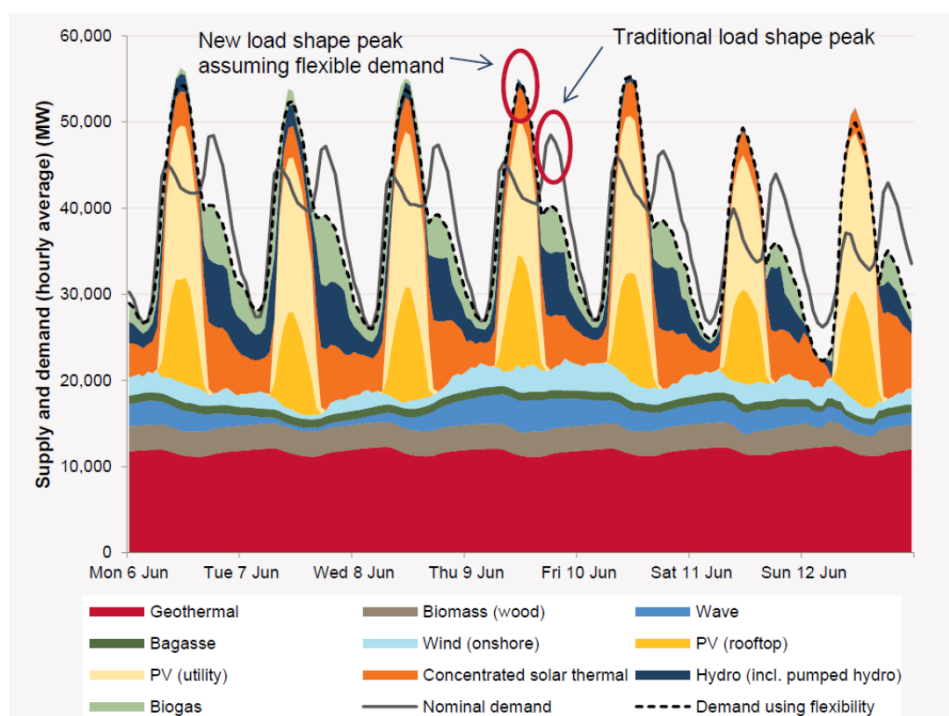


Figure 21: Sample forecast demand profile for 100% renewable electricity in the NEM from AEMO's 2013 study

From the point of view of a project developer, CSP plants offer a range of features in addition to providing emissions free electricity, that are rewarded either implicitly or explicitly in the market place. These include:

- moving energy sales to high demand periods,
- ancillary services (spinning and non-spinning reserves, etc),
- whole electrical network avoided cost,
- community / society benefits, and
- option / hedging value.

4.2. Carbon Emission Savings

The increasing supply of CSP will allow the replacement of carbon-intensive energy sources and significantly reduce Australia's global warming emissions. In 2016 Estela published the Solar Thermal Electricity Global Outlook estimating the CO₂ saving for several scenarios. Focusing only on the moderate scenario (see Figure 22) they have estimated that by 2050 cumulative saving 16,657million tonnes of CO₂ would be achieved.

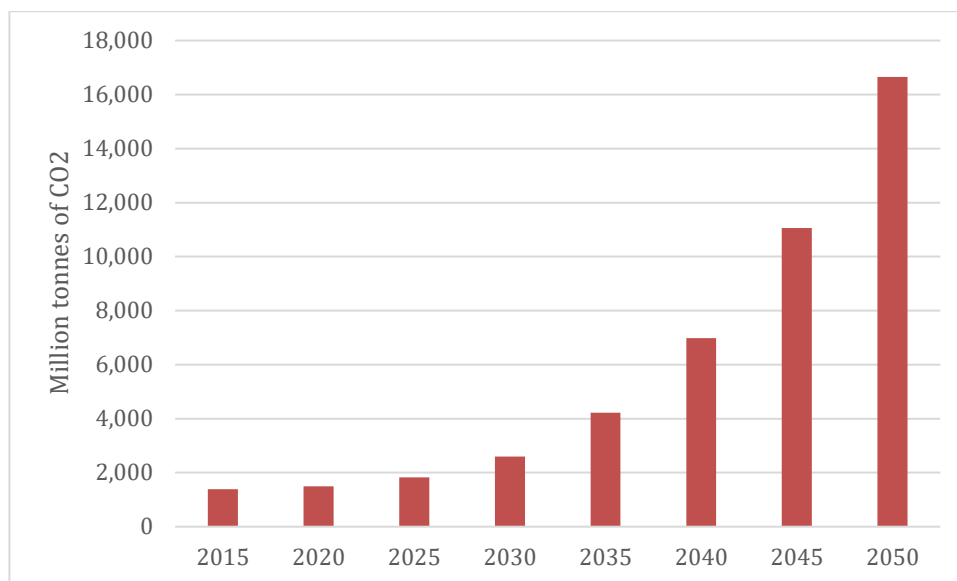


Figure 22: CSP Cumulative CO₂ saving projections (moderate scenario), Estela ,2016

4.3. Moving energy sales to high demand periods

ITP's 2012 study examined the potential income that could hypothetically be derived in the NEM based on historic price data, if a CSP plant with storage was configured for peaking generation. It was found that optimised dispatch could produce average sale prices up to double those of the average market price.

An approach to value generation via time shifting not widely discussed for CSP plants is the idea that thermal storage could simultaneously be used for price arbitrage in a wholesale electricity market if molten salt tanks are fitted with suitable electric heaters. If these were used to add extra energy to the tanks at times of very low or even negative energy prices due to high generation levels from wind for example, the result would be electricity storage and return for a round trip efficiency of around 30 to 40%, for very little extra capital cost. This is low compared to batteries at around 90% or pumped hydro at around 80%, so it is unlikely to be reason to build molten salt storage in isolation. It should also not be confused with the impact adding molten salt storage has on a CSP plant, which is to increase available energy not decrease it.

4.4. Ancillary services

Ancillary services are those services, other than energy supply, that are needed to run an electrical network in a stable manner. They can be categorised in different ways and the specific methods of meeting them can also be described in different ways. Figure 23 illustrates some of the concepts.

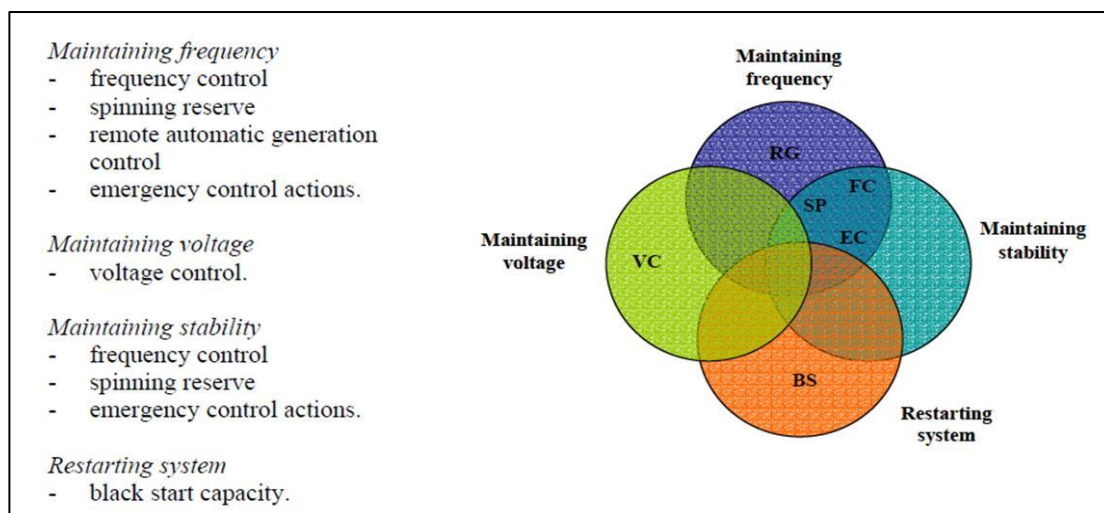


Figure 23: Classification of ancillary services needed and supplied, figure from (Elsen, 2004).

In the NEM, a range of ancillary services are already traded on a competitive basis in parallel with energy sales. The services are typically supplied by thermal (fossil) power stations characterised by synchronous generators, large amounts of angular momentum and the ability to ramp up and down as required.

CSP plants also employ turbines and synchronous generators and with storage they offer high levels of firm capacity. In the NEM, as in many electrical networks, ancillary services currently command low prices, because they are in oversupply due to the current dominance of fossil fuelled generation. In future scenarios of high levels of intermittent renewable generation, the market price is expected to increase significantly and could be as much as 10% of the total value realised.

4.5. Whole electrical network avoided cost

High firm capacity values offer the possibility that an appropriately located CSP plant could relieve the strain on network assets that are at the fringe of grid for example. This was the focus of the network benefits study carried out by the UTS team.

The UTS study found that in the East Coast NEM, CSP could avoid the need for augmentation in 72% of constrained sites examined, while 25% of the constrained sites were assessed as being cost effective. In the most extreme cases, the network benefit was sufficient to justify 100% of the CSP plant cost.

Predicted constraints were mapped by location and expected timing and estimated cost for upgrade. It was found that 72% of constraints could potentially be avoided by a suitably located CSP system. A cost model that determined LCOE by configuration, power capacity and date was used to assess the apparent cost effectiveness of plants that could be applied in this way. A hypothetical network benefit payment was determined from avoided cost of upgrade (noting that this monetisation of value is not automatically accessible under current market rules).

They found that the hypothetical value of a network support payment justified on avoided network investments at identified constrained locations in the NEM would be \$15/MWh on average but in specific locations was found to be up to \$134/MWh. A total of 533MW of systems were predicted to be cost effective out to 2023, with the plant capacity ranging from 8MWe to 120MWe and storage between 5 and 15 hours with the average being 40MWe with 10 hours of storage.

4.6. Community / society benefits

The high labour content and outright costs of construction for CSP plants have obvious positive effects in terms of employment generation and economic stimulation.

Abengoa reports that:

“In the US, with two projects (Mojave and Solana), the supply chains have created economic benefits and jobs across the US:

- More than 70% American goods and services,
- A national supply chain that includes 300 companies in 31 states and more are anticipated,
- Over 3,000 supply chain jobs created across America, and
- \$USD1.8 billion total investment into the local economy of those 31 states.”

Some of this supply chain represents demand for non CSP specific components and services. Some will represent businesses adapting to the provision of CSP specific products and services, this capability building will potentially contribute to cost reductions for subsequent projects. This apparent benefit however may be lost if a first project is not followed by a pipeline of projects.

In 2011, a definitive study of this aspect was carried out by Deloitte for the Spanish industry association Protermosolar (Deloitte, 2011). This study found that the economic benefit to the Spanish economy was well in excess of the net extra cost of the tariff support measures that were used to stimulate the industry.

Since the commencement of the FIT in 2007, investment grew and contributed Euro 1.65billion to Spain's GDP in 2010 – a period when Spain was significantly affected by the global financial crisis.⁹ Of this 1.65 billion Euros, it is reported that 89.3% was in construction and most of the

⁹ Note that the 2010 analysis is a snapshot of an industry in a growth phase, and so the cost of the FiT is small relative to the investment being made in construction. Over time the FiT cost will continue to accumulate, albeit discounted over time.

remainder is for ongoing expenditure for operation and maintenance of completed systems, with 2.67% being for R&D.

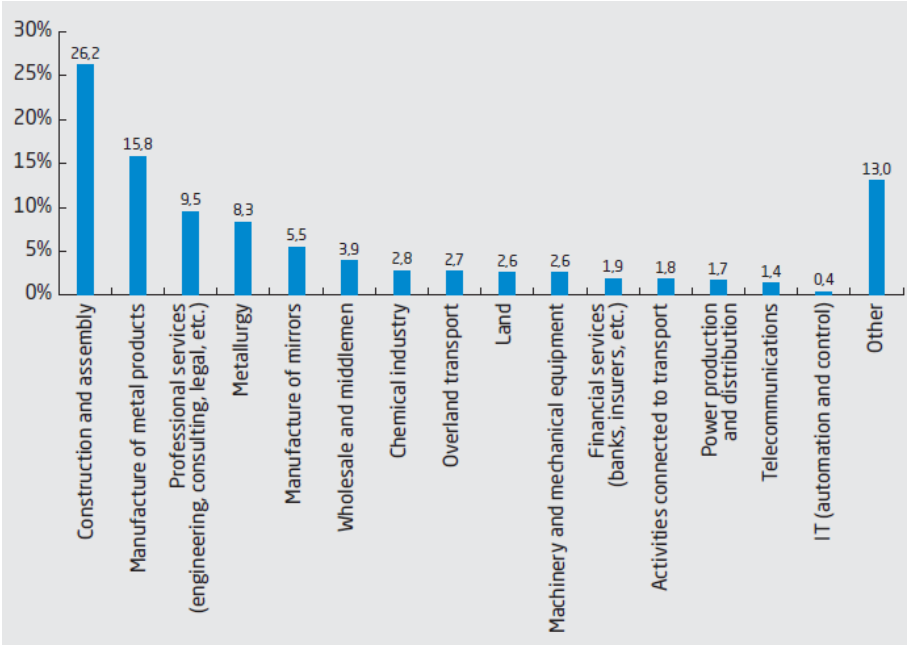


Figure 24: Contribution to GDP by different sectors during construction. Figure from Deloitte (2011).

This activity was spread over a variety of sectors with about 70% of the investment remaining in Spain (Figure 25). The report predicts that if the targets proposed for the period 2011 to 2020 are met, the contribution to GDP in 2020 could be of the order of 3.5 billion Euros.

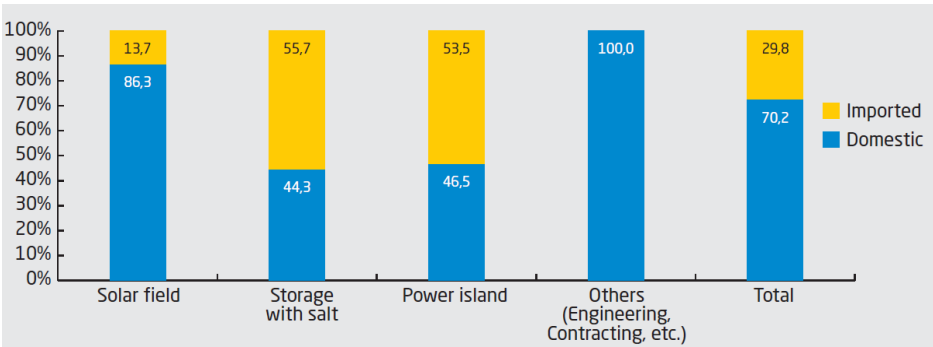


Figure 25: Percentage of investment which remains in Spain for CSP with storage. Figure from Deloitte (2011).

A total of 23,844 people were employed in 2010 according to the breakdown in Table 7, Much of the employment in construction directly helped a sector most affected by the overall economic

contraction at the time. It is estimated that 176million Euro's in employment subsidies were offset in 2010 as a result.

Table 7. Breakdown by industry activity of jobs created by the CSP Industry in Spain, 2008-2010 (Deloitte (2011))

Jobs	2008	2009	2010
Construction	11,713	18,492	23,398
Plan contracting, construction and assembly	4,399	6,447	8,049
Components and equipment	4,515	7,442	9,542
Jobs in the rest of the economy	2,799	4,603	5,807
Power production	13	123	446
Plant operation and maintenance	11	108	344
Jobs in the rest of the economy	2	15	102
TOTAL JOBS	11,724	18,600	23,844

An important observation is that as a consequence of the early initiative that Spain has taken to build the sector, Spanish CSP companies are now acknowledged world leaders in the field and are projecting that dominant role into other countries.

The overall balance in 2010 is shown as an investment in overall electricity premiums via the FIT, of 205million Euros, against a direct contribution to GDP of 1.65billion together with offsets in reduced fossil fuel imports (24M), CO2 rights (5M) and the further contribution of 407M Euro via tax and social security contributions.

The job creation potential of the CSP industry in Australia will be relevant especially during the construction phases where the labour needs are concentrated but as well during operation and maintenance. Furthermore indirect jobs will be generated in the rest of the economy as a consequence of these activities.

Estela's Solar Thermal Electricity Global Outlook (2016) estimated that under a moderate scenario between 9 and 11 jobs per MW would be created for installation activities and 1 job per MW for O&M activities. These job creation numbers are based on the experiences in Spain and the United States.

Figure 26 shows the Estela estimates regarding total job creation in the CSP field between 2015 and 2050. The analysis suggests that for a moderate scenario almost 1million jobs would be created.

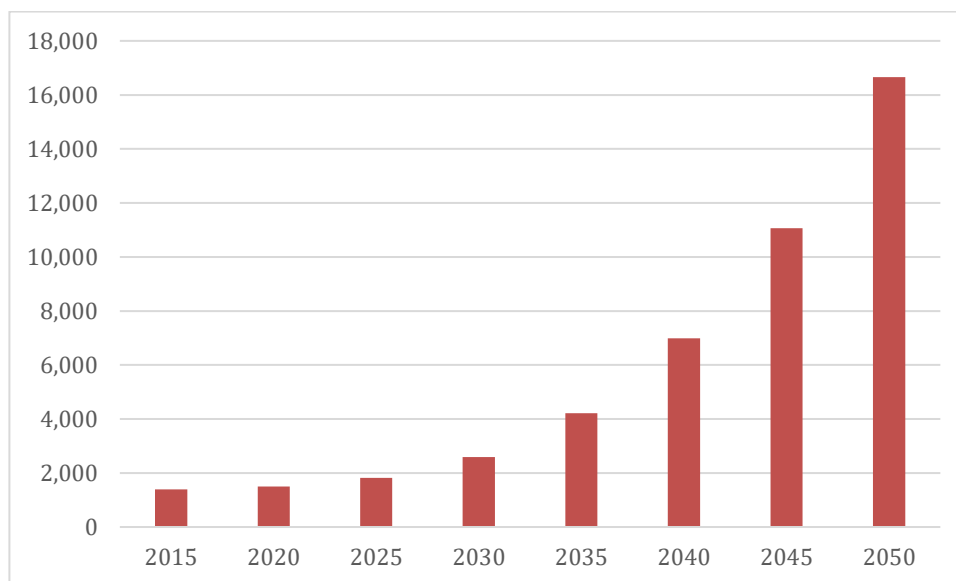


Figure 26: CSP Employment Outlook 2015-2050, Estela, 2016

The Spanish Renewable Energies Association (APPA) shows that for Spain between 2009 and 2013 the years where most of the CSP plants were developed a peak of 31,000 direct jobs were created in a single year (see Figure 27). However since 2014 no further plants have been constructed (as noted in section 3.4.1 above) but even so for O&M activities an average of 3,165 people are employed (direct jobs). It has to be noted that the installed capacity in Spain is of 2.3GW, this represents around 1.4 direct jobs per MW.

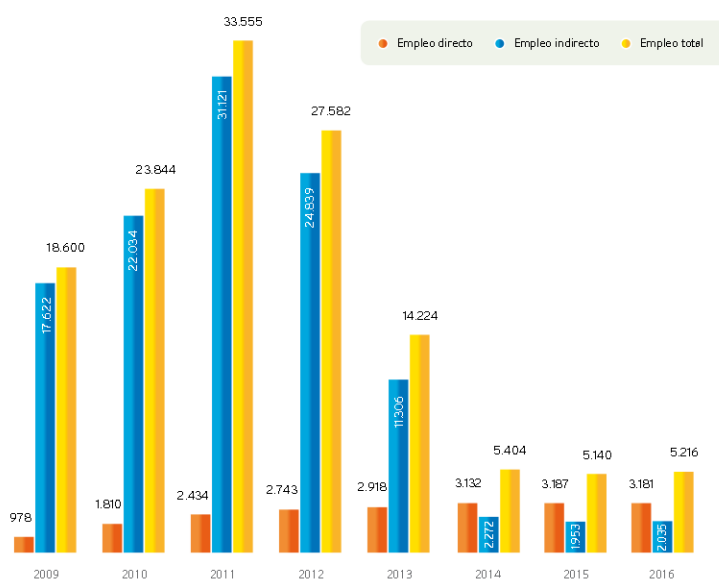


Figure 27: CSP sector jobs created 2009-2016, Appa, 2016

4.7. Option / hedging value

Option value can best be thought of as an insurance policy value. Countries that develop CSP capability, even though this has significant lead time and begins with some early and more costly projects, gain the option of being able to more cost-effectively access the technology in later years when the need for ancillary services and system balancing, e.g. replacement of an existing conventional power station fleet, is likely to be higher. The value can be linked to the extra cost that would be encountered via the alternative of importing components and capabilities from other countries at a future time.

4.8. Combining values

Whilst all these sources of value can be discussed in general terms, value propositions must be optimised on a case-by-case basis. Values change with geographical area, market rules and the other generating assets in place.

Studies by the Lawrence Berkeley National Laboratory (Mills and Wiser, 2012) and the National Renewable Energy Laboratory (Denholm and Hummon, 2012) in the United States value the additional flexibility of CSP plant at between USD 19/MWh and 35/MWh.

Optimum system configurations and operational strategies must be adopted for best overall value which can be a trade-off. For example, providing spinning reserve does not maximise energy sales revenue.

Table 8: Overall CSP energy value relative to the value of intermittent renewable electricity.

Source of increased Value	Estimate of relative value range increase over the value of an intermittent renewable energy supply
Time of Day benefit	5% to 100%
Ancillary services	0% to 10%
Network benefits	-10% to 100%
Societal / option value	10% to 20%
Total extra value for CSP with storage	50% to 150%¹⁰

Table 8 illustrates the approximate range that might be anticipated for the value of CSP relative to the benchmark of PV or wind generation without storage. It indicates that the benefits could considerably outweigh the approximately 50% higher cost of energy. It should be noted that the estimated range of total extra value is not simply the sum of lowest and highest values from the categories as a system with very small extra value is never likely to be built on one hand, and all

¹⁰ Note that the estimated range of total extra value is not simply the sum of lowest and highest values from the categories as a system with very small extra value is never likely to be built on one hand, and all sources of value can not be expected to accrue together as a plant designed for maxim time shifting capability may not be able to deliver as reliable network support.

sources of value can not be expected to accrue together as a plant designed for maxim time shifting capability may not be able to deliver as reliable network support. The range for network benefit includes a negative lower bound that captures the cost of some network extension in a situation where there is no benefit to the network from the addition of firm generation at the location.

5. CSP ACTIVITY IN AUSTRALIA

Despite its world leading solar resources, Australia is yet to be a major player in the CSP industry and does not have any 'utility scale' CSP systems in place. However Australia has 'punched above its weight' in many of its contributions from an RD&D point of view. .

5.1. Installed CSP systems

This section reviews some of the more historically significant activities that have produced smaller pilot scale systems that have been of high profile in Australia.

5.1.1. Meekathara Step 100



Figure 28: Meekatharra Collectors, (WA World of Energy).

In Australia's earliest attempt at a demonstration CSP system, Step 100 was built at Meekatharra in Western Australia in 1981-82. It was nominally 100 kW_e and employed small MAN trough units on two axis trackers, to provide heat for an ORC system based on a screw expander. It only operated for a short time and very little performance data has been published, (Hellweg, 1983).

Apparently, this system failed due to several issues and contains salutary lessons in this regard. These include the challenges of:

- building a demonstration system and integrating with existing generation in a remote area;
- combining a range of components of various levels of technical maturity in a complex system; and
- requiring de-bugging, commissioning and O&M services in a location where costs are high and appropriately trained staff may not be available.

5.1.2. White Cliffs

The early work of the solar thermal group at the Australian National University (ANU) led to the construction of a 14 dish system in the remote town of White Cliffs in New South Wales. Each dish is 20m² and has small flat mirror tiles bonded to a single fibreglass paraboloid. Superheated steam was generated directly in mono-tube semi cavity receivers and networked to a central power block using a 25 kW_e reciprocating steam engine / generator.

In 1998, this system was taken over and converted to CPV receivers by Solar Systems Pty Ltd as their first working R&D power station. However, Solar Systems removed their equipment and this plant has been mothballed since 2008. After more than 30 years, the dishes remain in reasonable condition.



Figure 29: White Cliffs Dish Systems (picture ANU)

5.1.3. Liddell Power Station

Liddell Power Station in the Hunter valley, NSW, hosts a 1,300m² array of Linear Fresnel reflectors installed by Ausra (now Areva solar) plus a subsequently completed additional 18,490 m², 9.3 MW_{th} Linear Fresnel array provided by Novatec Solar.

The Linear Fresnel arrays are configured to provide feedwater pre-heating to the coal fired power station, aiming for electricity generation of 4,400 MWh per year. These systems have seen little operation as the power station owners subsequently moth balled the generation unit to which they were connected. Their current status is largely unknown.



Figure 30: Liddell CSP Collectors.

5.1.4. Solar Systems' installations

Although not a CSP thermal technology, Solar Systems Pty Ltd developed dish concentrator based CPV systems that were installed at five stations in diesel mini-grid towns between 2000 and 2010. under the Australian Government's remote power program¹¹.



Figure 31: Solar Systems CPV at Windorah, Queensland (picture K Lovegrove)

¹¹ Renewable Remote Power Generation Program which operated from 2001 to 2009.

The project locations were Pitjantjatjara, Hermannsburg, Yuendumu, Lajamanu and Windorah. The power stations consisted of multiple, 500-sun concentrating dishes, (130m² each) with 22% efficient PV cells and pumped water cooling, operating in hybrid with the existing, diesel power stations.

Subsequently, the company assets was acquired by Silex Systems Ltd in 2010 and a 40 Dish 1.5 MW_e system was subsequently built in Mildura. Since then however activities have ceased.

5.1.5. Australian National University

The ANU has a track record in CSP that dates back to the founding of the group in the early 1970's by Carden and Kaneff. In 1994, following on from the 14 dish system at White Cliffs, the 400m² SG3 dish was completed. A mono-tube boiler receiver was used to generate superheated steam for a reciprocating steam engine driven generator.



Figure 32: The SG4 500 m² 'Big dish' at ANU (picture ANU)

The big dish size was motivated by analysis that suggested that large dishes were more cost-effective per unit area. Large-scale systems using centrally located, steam turbine generation were targeted.

In 2009, a dish design with 500m² aperture area was designed and built by ANU. The new dish was optimised for mass production for large-scale plants. This dish design featured 380 interchangeable square mirror panels which are also designed to provide a structural contribution for the dish. The mirror-panels are supported by a space frame and mounted on a baseframe running on wheels on a steel track, (Lovegrove et al, 2010).

Subsequently the commercial partner failed financially, The dish prototype at ANU continues to operate well as an experimental test facility and the technology remains an unexploited opportunity.

5.1.6. CSIRO

The CSIRO National Solar Energy Centre (NSEC) at Newcastle has a major presence in solar thermal R&D.

The NSEC has two tower / heliostat systems consisting of a 500 kW_{th} system and a newer 450 heliostat, 4,000m² collector field with a 30m tower. The tower systems are capable of concentrating solar energy to achieve temperatures beyond 1000°C. Solar Reforming of natural gas, steam generating systems and investigation of solar Brayton cycle systems are key areas of ongoing research. The centre has also worked with small experimental trough systems, storage and solar air-conditioning. A large range of projects have been carried out with these facilities with support from the Australian Solar Institute, ARENA and ASTRI.

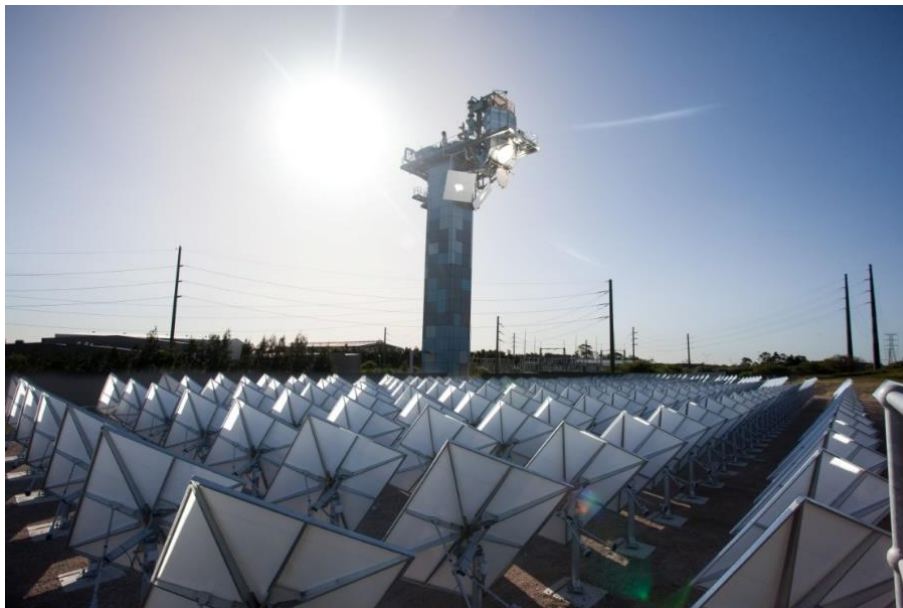


Figure 33: National Solar Energy Centre, Newcastle (Picture from CSIRO)

5.1.7. Solar Flagships

The Solar Flagships program was announced by the Federal Government in May 2009. The program aimed to facilitate 1 GW of solar power generation by 2015. The program was designed to support four, large-scale solar projects with up to \$1,500m of Australian Government funding. Originally, the program was designed to be a competitive, up to one-third (pre-tax) funding of chosen CSP and PV power stations. Round 1 of the program targeted 400 MW_e via one CSP and one PV project.

The overall Round 1 process attracted 52 proposals of which at least half are believed to be CSP. The four shortlisted CSP consortia were (Ferguson, 2010).

- 'ACCIONA Energy Oceania proposed to generate 200 MW using solar thermal parabolic trough technology at a single site in either Queensland or South Australia;
- Parsons Brinckerhoff proposed to construct a 150 MW solar thermal parabolic trough power station at Kogan Creek in Queensland;
- Wind Prospect CWP proposed to use linear Fresnel technology at Kogan Creek in Queensland to construct a 250 MW power plant; and
- Transfield proposed to convert the Collinsville coal-fired power station in Queensland into a 150 MW solar thermal linear Fresnel power plant.'

Of these, Acciona withdrew during the final evaluation phase. The ultimate successful applicant was the Wind Prospect / Areva SolarDawn proposal. The total project cost was indicated in the May 2010 announcement: 'Government will contribute \$464 million for the project in Chinchilla worth an estimated \$1.2 billion'.

Ultimately this project did not reach financial close or proceed. In retrospect, there are lessons to be learnt from:

- Attempting to procure a single project bigger than any that had been built globally at that time,
- Awarding the project largely on cost to a technology supplier without significant track record,
- Not ensuring as part of the program that an offtake agreement could be achieved.

5.1.8. Graphite Energy Storage

Lloyd Energy systems and a series of related companies (of which Solarstor is a currently active example), have worked on a Tower based CSP system that incorporates a receiver mounted graphite block thermal storage system. Concentrated radiation is directed into the downward facing receiver apertures and heats the graphite. Internal passages can subsequently be used to produce steam for power production.

A 3.5MW_e demonstration system was constructed at Lake Cargelligo as shown in Figure 34. It was supported under the Australian Government's 'Advanced Electricity Storage Technologies' program awarded in May 2007. Very little information on the project was ever released. It is now moth-balled. Another such pilot system is reported to have been constructed in China however again little is publically known about performance.



Figure 34: Multi tower, graphite energy storage demonstration at Lake Cargelligo, NSW

5.1.9. Kogan Creek Solar Boost

In May 2010, funding was announced for \$31.8m towards a CS Energy lead project to demonstrate the Linear Fresnel Reflector technology of the Areva Group. The project was to be attached to the existing Kogan Creek Power Station to provide a 44 MW electrical equivalent superheated steam solar boost to the coal-fired turbines. At 135MW_{th} this would be Australia's largest and first utility scale CSP array.

The components of the entire solar array were successfully constructed and installation partially completed by 2014. This project however stalled at that point, with a legal dispute between CS Energy and Areva coinciding with Areva's exit from solar. The array remains the property of CS Energy however they have not moved to complete the project to date and its future remains uncertain.



Figure 35: Kogan Creek Solar Boost array under construction (picture CS Energy).

5.1.10. Sundrop farms

As shown in Figure 36, a $1.5\text{MW}_e/36\text{MW}_{th}$ concentrating solar power system was constructed at Sundrop Farms in Port Augusta, South Australia (Sundrop Farms, 2018). This is a pioneering application of CSP in a combined heat and power (CHP) configuration. The steam produced by the solar field is partially expanded in quite a small steam turbine such that the exit temperature is sufficient to provide energy to other thermal processes.

Sundrop Farms utilises large, advanced greenhouses to allow for year-round tomato yields of around 15,000 tonnes per annum. Greenhouse inputs are fertilisers, freshwater, heating/cooling, and electricity. The solar plant contributes heat, power and freshwater to the greenhouses. Seawater is extracted for evaporative cooling and for desalination. The EPC contractor for the whole project was John Holland, with the Danish company Aalborg CSP responsible for the solar installation, for which they in turn sourced heliostats from the US company ESolar.

Aalborg CSP estimate that the system will produce $20,000\text{MWh}_{th}$ of heat, $1,700\text{MWh}_e$ of electricity, and 250,000 kL of freshwater annually. The Sundrop farms system is thus Australia's largest complete and operational CSP array.



Figure 36. Sundrop Farms greenhouses and concentrating solar power plant (courtesy of Aalborg CSP)

5.1.11. Vast Solar

Vast Solar Pty Ltd has worked for many years developing a modular multi-tower array system where each tower and heliostat array is sized at around 1.2MW_{th} . At the beginning of 2018, they are in the final stages of commissioning a 1.1MW_e (6MW_{th}) demonstration system. They are

pioneering the use of liquid sodium as a heat transfer fluid and propose to couple that to a molten salt based thermal store.



Figure 37: Vast Solar's CSP demonstration power station in Jemalong, New South Wales

The demonstration system features:

- 3,500 heliostats (mirrors) in five solar arrays,
- five high temperature receivers mounted on individual towers,
- a thermal energy storage system comprising a hot tank (565°C) and 'cold tank' (over 200°C),
- steam turbine electrical generation system, and
- a modular air-cooled condenser.

5.2. ARENA funded R&D

Since the establishment of the Australian Solar Institute (ASI) in 2009 and its subsequent incorporation into the Australian Renewable Energy Agency (ARENA), there has been over \$95m of investment by the federal government into CSP R&D.

A wide range of organisations has received support. This has led to the growth of several CSP-focused research groups. Among the research institutions, CSIRO, ANU, University of Adelaide and University of South Australia have the largest CSP research programs. There are also CSP research groups at the University of Queensland, RMIT, UNSW and other organisations, with growing industry linkages.

ARENA/ASI funding has resulted in a number of new research, test and demonstration facilities. Examples include the 6 MW_{th} Vast Solar system discussed in section 5.1.11, receiver, power cycle and thermal storage test setups at CSIRO Newcastle's solar tower facilities and a high-temperature thermal storage test facility at the University of Adelaide.

Investments related to Tower systems dominate with an allocation of 82% of invested funds. This reflects the overall dominance of CSIRO in CSP research, the initial strategic decision by ASI to give priority to high concentration systems and then by the Australian Solar Thermal Research Initiative (ASTRI) to also follow the tower route.

Funding priorities have been centred around the areas of manufacturing cost reduction and efficiency improvements with approximately one third of funds spent on each, while about 10% of funds was invested in new concepts, as illustrated in Figure 38.

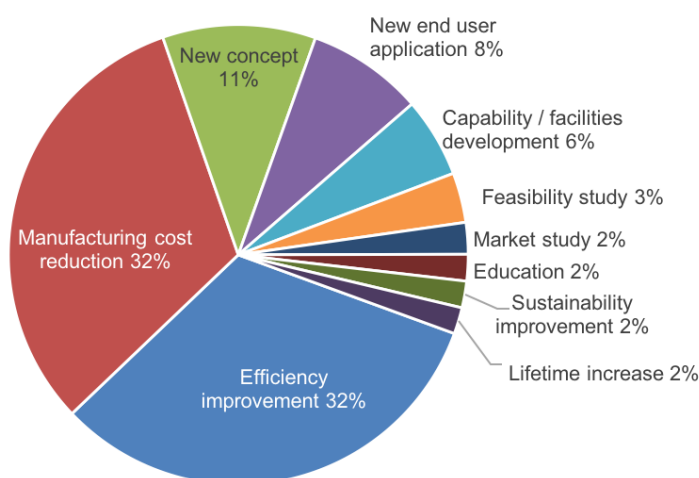


Figure 38: CSP R&D funding by type of research.

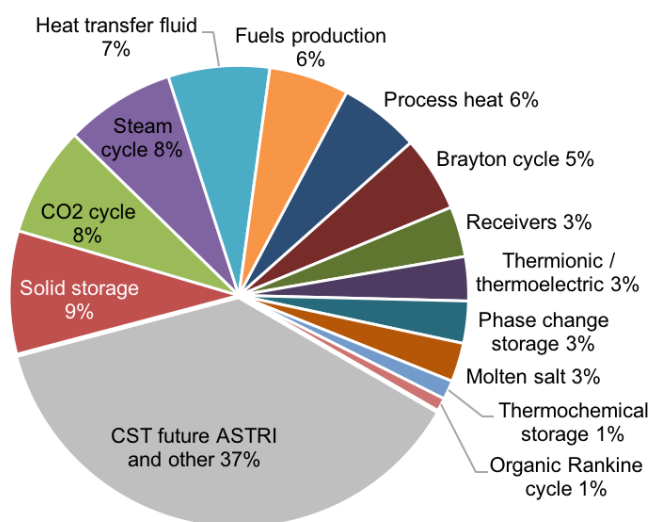


Figure 39. ARENA CST R&D funding by technical subject.

As shown in Figure 39, research funding has been spread over a broad range of technical areas, both in terms of applications and technological areas. Major investments have been made into new power cycles, receivers and thermal storage media in order to improve the power plant efficiency.

5.3. Previous studies of CSP potential in Australia

A number of detailed studies and reports on the potential for utility-scale solar power plants in Australia have been undertaken over the last decade. The following summarises the aspects covered and the key conclusions reached.

5.3.1. COAG High Temperature Solar Thermal Roadmap

The context and priorities for CSP in Australia have been examined with a 2008 High Temperature Solar Thermal (HTST) Roadmap commissioned on behalf of the Council of Australian Governments, (Wyld Group, 2008). Key conclusions were that High Temperature Solar Thermal represented a major opportunity in Australia, with an ultimate potential for grid-connected systems in the order of 20,000 MW_e.

The Roadmap noted that the Federal Government's Renewable Energy Target, that was expanded to '20% by 2020' in 2008, would not assist CSP to come down the cost curve, because it would largely be met by mature technologies, particularly wind.

The Roadmap also identified that a carbon price would need to reach AU \$50 per tonne to make a major contribution to CSP investments. The performance and economics of CSP plants located in Port Augusta, North West Victoria, Central and North West NSW, Darwin-Katherine Interconnected system, Alice Springs / Tennant Creek, Kalbarri and a remote large town / mine were analysed. A range of cost gaps were identified.

5.3.2. Beyond Zero Emissions' Stationary Energy Plan

The not for profit group Beyond Zero Emissions produced a 'Zero Carbon Stationary Energy Plan' Wright and Hearps (2010). This was a detailed case study of a scenario based on large wind turbines and CSP tower / heliostat type plants with molten salt storage to provide 100% of Australia's stationary energy needs in 10 years. By analysing one particular solution in detail, the plan showed that a 100% renewable energy solution is technically feasible and that capital costs, whilst very large, are not beyond the capacity of the Australian economy.

A key part of the plan's analysis was modelling of the assumed mixture of technologies both with and without energy storage within the National Electricity Market (NEM). The plan also proposed major grid extensions, including connecting the NEM to Western Australia and establishing major CSP hubs at the sites indicated in Figure 40 .

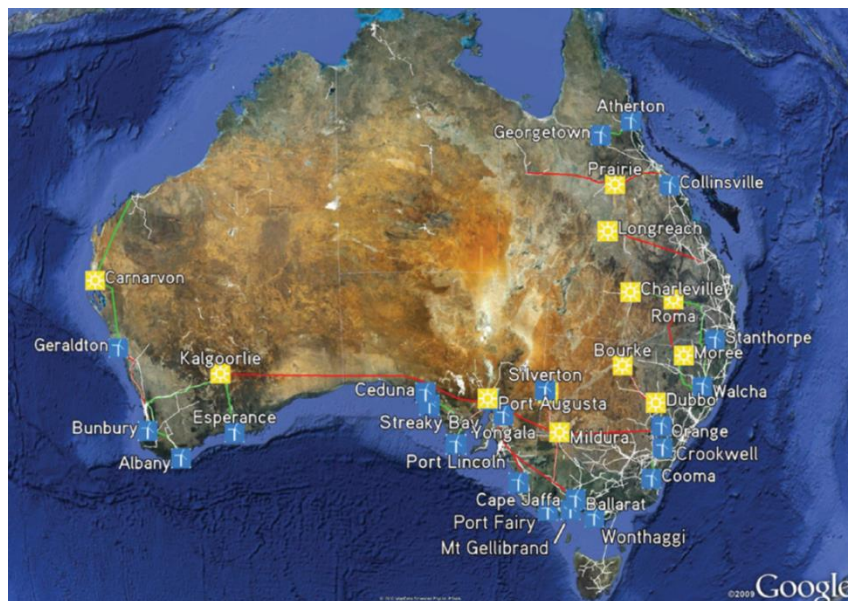


Figure 40 Solar and wind farm sites plus major grid extension suggested by Wright and Hearps (2010).

5.3.3. NSW Solar Precinct Study

AECOM (2010) completed a 'Pre feasibility study for a solar precinct' for the NSW government. The study analysed five NSW locations with a view to siting a large scale precinct, pre-approved for large CSP or PV plants.

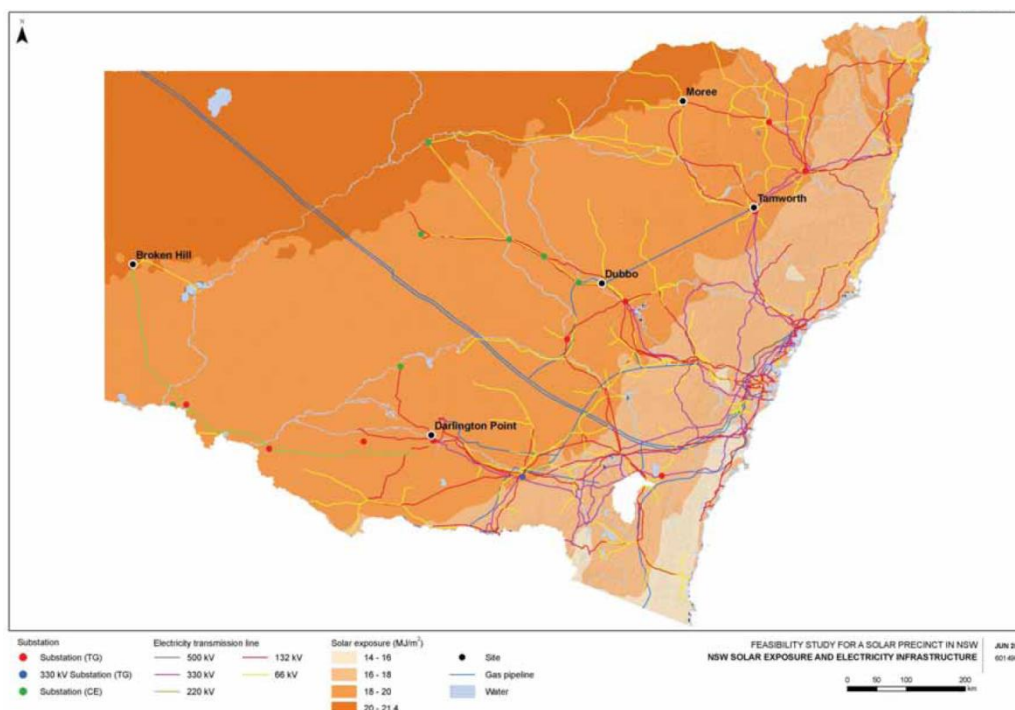


Figure 41 Sites examined for solar precincts in NSW compared to solar resource (AECOM 2010).

The sites considered were Broken Hill, Darlington Point, Dubbo, Moree and Tamworth. The study concluded that Broken Hill was the most favourable for connection of a 250 MW plant as it combined good solar resources with minimal additional transmission infrastructure required.

In addition, it was found that with the exception of Darlington Point, it was feasible to connect a 1,000 MW precinct to the Transgrid network at each site. Based on the capital cost assumptions used, solar trough, gas hybrid plants were found to have the lowest LCOE's of the options considered. For the possible solar only options, solar towers were found to be lowest LCOE.

5.3.4. Queensland CSP Pre-feasibility Study

The Queensland Government commissioned Parsons Brinkerhoff together with input from the Clinton Climate Initiative to produce the 'Queensland Concentrated Solar Power Pre-feasibility Report', (Parsons Brinkerhoff 2010).

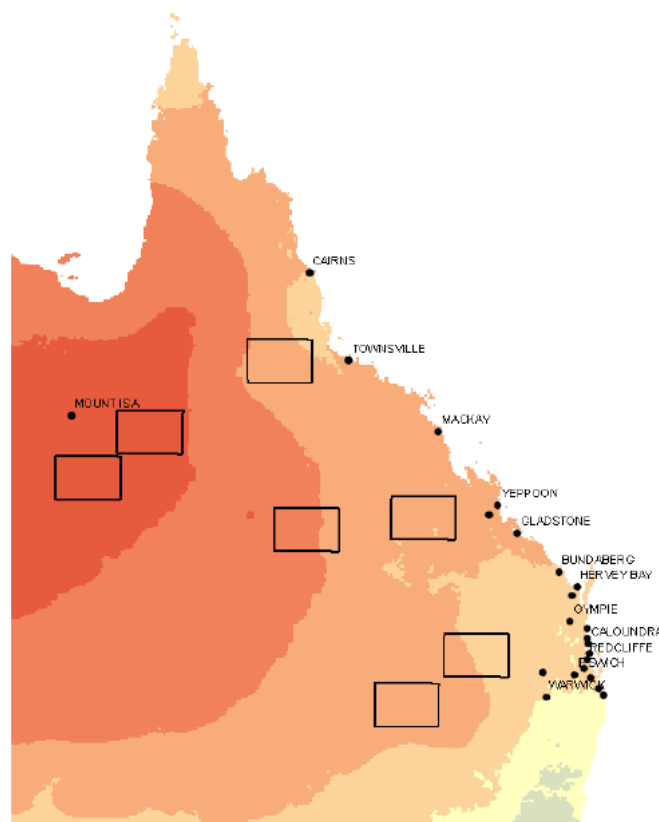


Figure 42: Investigation zones for CSP deployment in Queensland, compared to solar resources (Parsons Brinkerhoff 2010).

This report investigated possible sites and costs in seven areas scattered through the state in regions with perceived reasonable prospects of grid connectivity and good solar resource. A Geographic Information System (GIS) analysis of solar resource, land characteristics and grid

and other infrastructure issues. Ultimately the regions of investigation were generalised and a preferred area for each identified; specifically; North Queensland – Julia Creek; Central Queensland – Barcaldine and Southern Queensland – Miles.

The Central and Northern regions have the better solar resource but require extensive transmission connection work, whereas the southern region is close to the existing Powerlink grid. Using the costs that were based on solar field costs provided by the Clinton Climate Initiative combined with Parsons Brinkerhoff estimates of Power Block and construction costs, the financial analysis showed that all options had a negative Net Present Value (NPV) without some form of policy / subsidy intervention. For the options examined, the Miles site (Eastern most block on Figure 42) offered the most cost effective option.

5.3.5. Site Options for CSP Generation in the (WA) Wheatbelt

'Site options for Concentrated Solar Power Generation in the Wheatbelt', Clifton and Boruf (2010), produced for the Western Australian Wheatbelt Development Commission is essentially a GIS mapping exercise for the wheatbelt region that largely surrounds Perth. An overall map of most prospective sites is shown in Figure 43.

It can be noted that in terms of solar resource levels, this region of WA, whilst good, is by no means the best in the state. However, it does have the advantage of being coincident with the South West Interconnected System main-grid, whereas many of the higher solar regions are not.

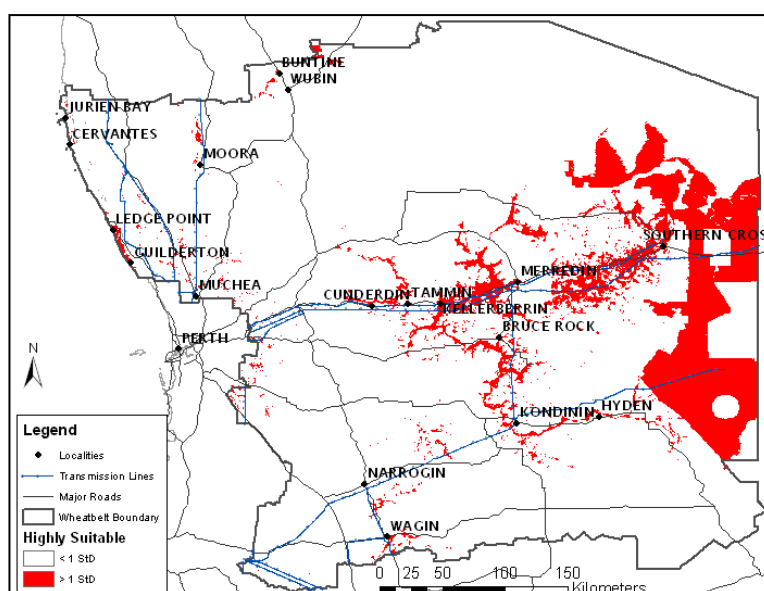


Figure 43 Evaluation of site suitability for CSP in the Western Australian Wheat Belt (Clifton and Boruf 2010).

5.3.6. WA Renewable Energy Assessment

Evans and Peck completed a detailed study of renewable energy potential including CSP for the Mid West and Pilbara regions of WA on behalf of the Department of Resources Energy and Tourism (Evans and Peck, 2011a, 2011b).

The Pilbara has some of the best annual solar DNI resources in the world and the Mid West is also very sunny. The regions have limited electrical infrastructure, characterised by some interconnection but also a large amount of autonomous generation operated for mining operations. Existing generation is by large capacity diesel engines and gas turbines.

The Pilbara demand was expected to grow from 1,800 MW capacity to 4,500 MW by 2020. The Evans and Peck studies considered a range of renewable energy options including wind, PV and CSP. The CSP options were based around trough technology and included 150 MW_e plants with or without energy storage plus an Integrated Solar Combined Cycle option.

Their evaluation of LCOEs indicated large scale diesel systems generating for \$300/MWh at a diesel price of \$22/GJ (\$0.85 per litre). Their base case for CSP options indicated a cost of energy of \$400/MWh or more, however a range of measures were identified that could potentially make the CSP option more cost-effective.

5.3.7. Worley Parsons Advanced Solar Thermal study

A major private study whose existence is known and some conclusions of which have been shared publicly (Beninga, 2009) is the 'Advanced Solar Thermal' study coordinated by Worley Parsons together with a consortium of investors. This included an extensive GIS mapping exercise that examined CSP development constraints:

- Environmental - Rivers and water bodies; Avifauna; Vegetation; Wetlands; Land tenure.
- Social - Native title; Airports; Population; Indigenous estate; Land use; Mine sites; World heritage.
- Engineering - Highways; Rail; Cyclone risk; Slope; Wind velocity; Soil types; Gas pipelines; Transmission.
- Economic - Transmission; Land cost; Population centres; Rivers and waterbodies; Slope; Wind velocity; Highways.

This resulted in the constraints map shown in Figure 44. The actual assumptions used have not been published and aspects such as assumptions on impacts of land slope limitations for example are quite technology dependant. However, overall the map provides a good indication of issues other than actual solar DNI resource level.

The preferred CSP system configuration identified was a 250 MW_e parabolic trough plant with Solar Field Mirror Area - 1.5 million m² and two tank molten salt storage for 1¼ hour storage at full plant output.

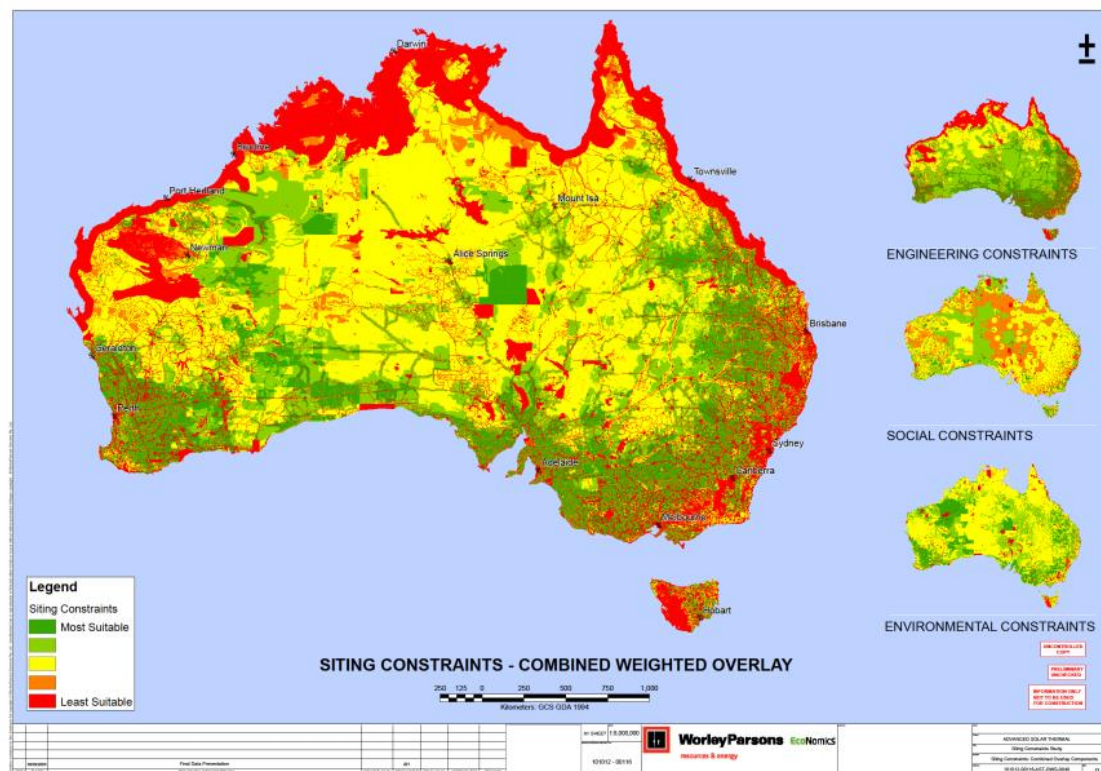


Figure 44: GIS mapping of CSP site constraints (Beninga 2009).

The annual generation potential of such a plant at locations around the country is illustrated in Figure 45.

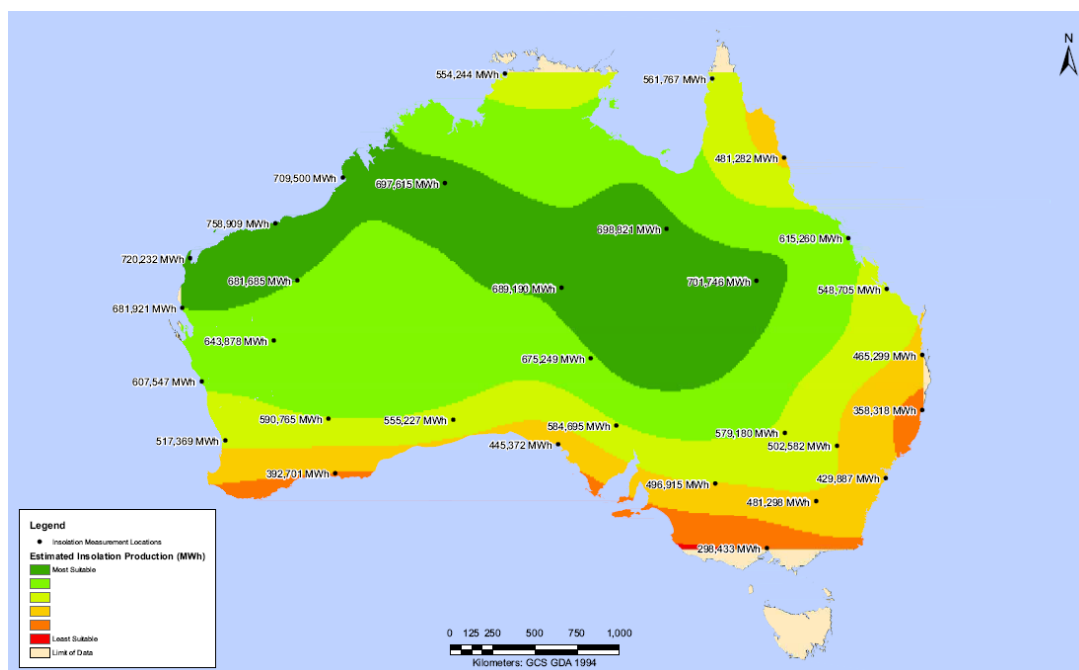


Figure 45: Generating potential of a 250 MW_e trough plant at sites across Australia (Beninga, 2009).

5.3.8. ITP potential for concentrating solar power in Australia

ITP has previously completed a detailed study, *Realising the Potential for Concentrating Solar Power in Australia*. This 2012 study reviewed the status of the global industry, activities and previous studies in Australia. It also analysed construction costs based on international experience transferred to Australian conditions. Construction costs, combined with O&M costs, and agreed financial parameters¹² were used to analyse the Levelised Cost of Energy (LCOE) from hypothetical Australian CSP plants.

A 64MW_e trough plant without storage located in Longreach Queensland was chosen as a baseline and it was concluded that an Nth of a kind¹³, (NOAK) plant counting costs to the plant gate, could offer a real dollar LCOE (in 2012) of approximately \$252/MWh. This baseline system was chosen at that time as representing the most technically conservative CSP plant configuration located at close to the most favourable site within the East Coast National Electricity Market region. At the time maximum market value was assessed as \$125/MWh, clearly a major gap between cost and potential income.

Extensive analysis then examined the key effects of:

- system size,
- location, and
- likely cost reductions over time.

A range of non-technical barriers were considered and policy recommendations were made. In the spirit of road mapping, it was suggested that it would be technically possible for Australia to reach an installed CSP capacity of 2GW_e by 2020 and 100GW_e by 2050, following on the expected completion of the 250MW_e Solar Flagships project that was announced at the time. It was also concluded that based on likely rates of global CSP deployment and likely range of cost reductions per doubling of capacity, that LCOE and income in Australia could converge in between 6 to 18 years.

5.3.9. ISF network benefits of CSP

As has already been discussed in sections 4.1 and 4.5 the Institute for Sustainable Futures (ISF) from the University of Technology Sydney, lead a 2013 study to investigate the potential network benefits of CSP systems with thermal storage in the Australian NEM. (Rutovitz et al., 2013), The central hypothesis was that there are various locations at which distribution or transmission network constraints are forecast at particular times due to shifts in location and distribution of electricity demand over time. This leads to tipping points where large investments can be required

¹² The financial parameters used were: loan fraction 60%, loan period 15 years, loan interest 7.78%, discount rate for equity 10.29%, depreciation period 20 years, project life 25 years, inflation 2.5%, O&M costs 1.8c/kWh, allowance for construction finance costs 6%.

¹³ "Nth of a kind" (NOAK) system indicates that a number of systems (e.g. N < 5- 10) would have been built so that construction teams and supply chains have developed experience and overcome initial inefficiencies.

to replace upgrade or duplicate network assets in order to keep system operation within accepted standards. If generation assets with suitable 'firm capacity' were installed in appropriate locations, otherwise large investments in network upgrades could be avoided.

Indicative firm capacity was evaluated and values greater than 80% were used as the cut-off to consider that the CSP plant was technically able to avoid the constraint. This was combined with the requirement that it would be technically possible to connect a plant of sufficient size to avoid the constraint.

Predicted constraints were mapped by location and expected timing and estimated cost for upgrade. It was found that 72% of constraints could potentially be avoided by a suitably located CSP system. A cost model that determined LCOE by configuration, power capacity and date was used to assess the apparent cost effectiveness of plants that could be applied in this way. A hypothetical network benefit payment was determined from avoided cost of upgrade (noting that this monetisation of value is not automatically accessible under current market rules).

Specific results are shown in Table 9.

Table 9. Potential 'network positive' CSP installations by state.

Queensland Sites	Cost benefit \$/MWh	Size, MW	Year
Charleville ZS	\$67	20	2022
St George ZS	\$60	27	2022
Roma BSP	\$41	120	2022
Emerald ZS	\$17	70	2020
Clermont ZS	\$2	20	2023
Yarranlea ZS	\$2	30	2024
Cape River ZS	-\$4	20	2022
Torrington ZS	-\$7	55	2021
Millchester BSP	-\$18	75	2017
Chinchilla BSP	-\$32	30	2019
Blackwater ZS	-\$45	22	2018
Dysart BSP	-\$48	120	2015
Warwick BSP	-\$48	111	2017
Stanthorpe ZS	-\$49	20	2017
Chinchilla Town ZS	-\$87	16	2017
Pampas ZS	-\$91	11	2019
West Warwick ZS	-\$107	28	2016
Clifton ZS	-\$118	8	2022
West Dalby ZS	-\$137	15	2016
Stanthorpe Town	-\$168	15	2017

Note TS = Terminal Station, ZS = Zone substation and BSP = Bulk supply point.

NSW Sites	Cost benefit \$/MWh	Size, MW	Year
Gunnedah supply	-\$11	95	2019
Beryl TS	-\$66	95	2016
Mudgee ZS	-\$100	19	2019
TWT-QDI line	-\$108	19	2017
GW-THA line	-\$118	15	2015
Bourkelands ZS	-\$129	13	2018
OR-BNY line	-\$153	18	2016

Victoria Sites	Cost benefit \$/MWh	Size, MW	Year
Wemen TS	\$18	77	2021
KGTS-SHL line	-\$49	58	2016
Wangaratta ZS	-\$54	66	2018
Cobram East ZS	-\$61	38	2017
Boundary Bend ZS	-\$61	33	2015
Ballarat TS	-\$64	120	2022
Merbein ZS	-\$67	26	2015
Eaglehawk ZS	-\$85	54	2016
Bendigo TS	-\$96	120	2014
Maryborough ZS	-\$97	27	2019
Thomastown ZS	-\$159	84	2019
Melton ZS	-\$194	66	2016
Sale ZS	-\$226	40	2015
Bacchus Marsh ZS	-\$298	27	2014
Thomastown ZS	-\$159	84	2019

South Australia Sites	Cost benefit \$/MWh	Size, MW	Year
Monash TS	\$178	50	2022
Hummocks TS	\$32	120	2021
Mt Barker S TS	-\$16	120	2023
Clare ZS	-\$173	10	2016

They found that the hypothetical value of a network support payment justified on avoided network investments at identified constrained locations in the NEM would be \$15/MWh on average but in specific locations was found to be up to \$134/MWh. A total of 533MW of systems were predicted to be cost effective out to 2023, with the plant capacity ranging from 8MWe to 120MWe and storage between 5 and 15 hours with the average being 40MWe with 10 hours of storage.

The cost benefit shown is their assessment of LCOE – energy market income – assessed network benefit. Changes to market conditions and the cost model for CSP can be expected to change this however the approximate relativity between the opportunities could be expected to still be valid.

5.3.10. Alinta Port Augusta pre-feasibility study

In 2015, Alinta completed a pre-feasibility study to assess the viability of a 50 MW_e CSP plant located near Port Augusta, SA. This study was carried out in the lead up to the closure of the Northern Power station (brown coal fired) that was operated by Alinta at that site. The study was financially supported by the ARENA and was terminated after the pre-feasibility stage as Alinta assessed that a CSP plant in Port Augusta was not economically feasible under any of the scenarios and parameters considered.

The Milestone 4 Report prepared by Alinta is the final report of the pre-feasibility study (Alinta, 2015). Available technical reports prepared by Parsons Brinckhoff (commissioned by Alinta) include a Siting Study Report in July 2014 (Parsons Brinckhoff, 2014a), an Options Study Report in July 2014 (Parsons Brinckhoff, 2014b) and a Balance of Study Report in Dec 2014 (Parsons Brinckhoff, 2014c).

Plant location was chosen approx. 13 km south-east of the town of Port Augusta (as opposed to the plant location of the Aurora project approx. 30 km north-west of Port Augusta). The DNI for the chosen site was determined to be 2,445 kWh/m²/year (in close agreement with the DNI reported for the Aurora plant site of 2475 kWh/m²/year; difference: 1.2%).

The study compared parabolic trough, linear Fresnel and power tower technologies, both in stand-alone and hybrid configurations with existing coal-fired power plants. A power-tower system with molten salt heat transfer fluid and storage medium was selected for further analysis in the project, which yielded the lowest LCOE. The plant was designed with a 50 MW_e power block with a sea-water cooling tower for heat rejection and 15 hours of thermal energy storage. This resulted in a predicted annual capacity factor of 70% and an annual electricity production of 301 GWh_e.

The project costs were estimated by a combination of scaled costs obtained with the NREL System Advisor Model, estimates obtained with the Thermoflow SteamPRO software for the power cycle, and internal and external experience. The heliostat field cost was estimated to be \$150/m² or \$138M for the entire field in 2014 AUD after discussions with manufacturers and installers of heliostats. Power block was estimated at \$1480/kW_e. Contingencies were applied to each technology component separately. The average contingency was 14.9%. The total capital costs, including EPC and owners costs were estimated at \$577M, the O&M costs at \$7.9M pa, both in 2014 AUD. The discount rate used for the project was 12%. With this data, an LCOE of \$201/MWh was calculated, whereas the realised revenue was estimated to be \$96/MWh. Consequently, no positive NPV could be achieved.

In this study industry players did not provide competitive bids to discover price. Up to 13% lower capital costs were deemed feasible based on general discussions with industry. This would result in a capital cost for the plant of around \$500M. The project was deemed financially unviable on this basis.

5.3.11. Abengoa Perenjori Solar Tower Project

ARENA supported a study led by Abengoa to conduct a feasibility study of a 20 MW_e solar power tower plant with 7 hours of thermal energy storage in Perenjori, WA. The study has established the system parameters listed in Table 10. The project considers the use of the heliostat technology developed by CSIRO, in combination with Abengoa's molten salt solar tower technology. The plant would provide electricity to a mining company with suitable load requirements and provide electricity to retailers through integration into the north-eastern fringe of WA's South Western Interconnected System (SWIS).

Table 10: Design and performance parameters of the proposed Perenjori CSP plant.

Parameter	Value
Configuration	Molten salt tower with surround field
Storage	7 hours
Nameplate capacity	20MW _e
Turbine gross conversion efficiency	40.8%
Total heliostat area	231,000m ²
Annual average DNI assumed	2,519kWh/m ²
Annual generation based on average DNI	94GWh _e
Capacity factor at Perenjori	53.7%
Capital cost including construction finance	\$288M

The plant is configured for maximum replicability, with high capacity and dispatchability, with end-of-grid connection providing network benefits, with technology that is considered as having the steepest cost reduction trajectory, in a location with excellent solar resource, at a scale that is large enough to strongly benefit from economies of scale. The thermal storage would enable the plant to provide power during the evening peak in the SWIS. The project aims to serve as a demonstration plant to showcase the technology and to accelerate the cost reduction in the technology.

The Perenjori study found that in 2015 such a system would have cost \$288M. This cost figure represents the costs of a first-of-a-kind system at a sub-optimal size of 20 MW_e in a remote location. Correcting for these three cost factors, an analysis conducted by IT Power in 2015 on behalf of Abengoa estimated that an n-th-of-a-kind system with 100 MW_e capacity operated at a higher DNI Australian site could produce electricity at a LCOE of \$177/MWh at the beginning of 2015.

There is currently no technical project report available online. Abengoa Solar's parent company experienced financial difficulties that came to a head in 2015 and consequently the Australian office was closed although the company is continuing to pursue projects globally.

5.3.12. Ratch Collinsville Power Station retrofit study

An ARENA funded study led by Ratch Australia considered the feasibility of converting the existing 180 MW coal-fired Collinsville Power Station in Queensland to a 30 MW hybrid solar thermal/gas power station. Coal-fired power plants nearing their lifetime are considered a potential opportunity to reuse part of the existing infrastructure for the construction of solar thermal power stations. This project looked into a specific example in order to develop a better understanding of whether and how this could be accomplished and to identify needs for cost reductions in solar thermal plant technology. This particular project was deemed unfeasible due to the high capital costs.

The plant's solar field was designed with Novatec linear Fresnel "SuperNova" direct steam generation collectors. The plant was planned to operate from 7 to 22h Mon-Fri at 30 MW with the gas-fired boiler backing up the solar steam generator. Annual production was estimated at 131 GWh_e, with 42% solar contribution.

Total capital costs were estimated at \$286M in 2014 AUD, with the solar field contributing approx. 1/3 to the costs (\$98.8M). Based on the stated reflector area of 175,000 m², this would correspond to a specific solar field cost of \$565/m² (of reflector area), which appears to be unrealistically high. O&M costs were estimated at approx. \$6M pa. The LCOE was estimated at \$297/MWh. Based on these estimated costs, the plant would require a 50% reduction in capex for the project to be considered economically viable.

5.4. ARENA's CST Request for Information

The Australian Renewable Energy Agency (ARENA) issued a Request for Information (RFI) to test the market for CST (i.e. CSP) projects on 25 May 2017 (ARENA, 2017). This has been analysed by ITP on behalf of ARENA and a public version of the analysis that suitably protects commercial in confidence aspects has been released.

The RFI process was designed to examine the potential for a possible program supporting the deployment of CST systems in Australia. The result was:

- 31 responses building on experience from every significant CST system globally.
- Directly expressed and implied interest in involvement in CST deployment in Australia.
- Universally positive views on the future of CST.
- All responses referred to the key advantage of cost effective, integrated thermal energy storage and the characteristics of dispatchable generation via synchronous generators.
- A clear indication that a large scale competitive CST process in Australia would be well subscribed

As shown in Table 11 respondents included large companies who have been instrumental in the global CSP industry over the past decade, plus small companies developing new technology approaches, as well as some key industry associations and others. In addition to Australian based companies, responses were received from Spain, USA, Germany, Italy, India and Chile. While a few responses are brief, most include an impressive level of detail and represent a significant effort, indicative of the interest in Australia as a future market.

Overall, the combined global experience in CSP is well represented with the total sector experience of respondents in excess of the total existing installed capacity, reflecting that respondents have in many cases been involved in the same projects in different roles.

Responses are universally positive about the future of CSP. All respondents referred to the key advantage of cost effective, integrated thermal energy storage in various levels of detail. This included characteristics of dispatchable and flexible generation coupled to the benefits of synchronous generation with inherent inertia. The ability to configure plants for dispatch strategies ranging between peaking to continuous output is widely discussed with many specific examples provided.

The cost discovery aspect of the RFI has been limited as might be expected. Major companies will be circumspect about their competitive position until a specific competitive process that they wish to succeed in is offered. The most ambitious cost estimates that were provided came from the smaller technology development companies who do not yet have a track record of deployment but clearly wish to sell the potential of their approaches.

Table 11. Submissions received in order of level of previous experience in the role.

Industry role	Country of origin	Experience in role (MWe approx)
Engineering services	Australia	7,700
Industry association	Spain	4,000
Industry association	Europe	3,500
Technology provider, EPC	Spain	2,060
Industry association	Germany	2,000
Component supplier	Chile	1,000
Engineering services	Spain	1,000
Technology provider	Spain	1,000
EPC, Project Developer	Spain	700
OEM, EPC,	Spain	500
Technology provider, Project developer	USA	500
Technology provider	Belgium	150
Technology provider, Project developer	USA	100
Consultant	Australia	90
Project Developer	Abu Dhabi	30
OEM, EPC,	Germany	30
Project developer	India	10
Developer, Technology supplier	Australia	3
Technology developer	Australia	1
Technology developer, component supplier	Australia	0.1
Technology developer	Italy	0.1
Technology developer	USA	0.1
Industry association	Australia	0
Project Developer	Australia	0
Research	Australia	0
Technology developer	Australia	0
Technology developer	Australia	0
Technology developer	USA	0
Technology developer	USA	0
Industry association	Australia	..
Government	Australia	..

Experienced companies and industry associations offered commentary based on recent international procurements and publicly available reports such as the IRENA 2016 report (IRENA, 2016). All were confident that cost reductions have been occurring and will continue. A number of experienced players provided detailed discussions of the various areas from which they are

confident cost reductions would be contributed even though they did put down their own estimate on current LCOE.

It is universally acknowledged that CSP LCOE is higher than PV at the present time, but respondents argue that the extra values offered justify such extra cost. Significantly this position was also offered by large international players who have successful track records in large scale PV as well as CSP. The complementary nature of the two was also noted. Many submissions note that one of the continuing challenges to CST deployment is the general lack of specific reward in Renewable Energy support mechanisms (such as Australia's RET) for the extra desirable benefits that CSP with storage brings.

The RFI process made a general reference to the context of the specific support of \$110m equity investment that is on offer from the Australian Government for a Port Augusta project. A minority of responses outline a specific project specification for which they could seek ARENA support, a further subset of these mention specific sites such as Port Augusta.

It is clear that any large scale competitive process to advance CST in Australia would be well subscribed by a critical mass of experienced players as well as smaller players seeking to progress towards commercialisation.

5.5. Summary

Whilst Australia has engaged with CSP over an extended period and many of the small demonstrations and pilot projects look visually impressive, the country has yet to engage with the industry in a serious manner. The largest working array, the 36MW_{th} Sundrop farms system is still very small when compared with a typical international utility scale project of around 600MW_{th} / 100MW_e. Much of the activity in Australia so far has been driven by startup companies developing systems from first principles, or R&D activities in institutions.

There have been a series of unsuccessful initiatives, including Solar Flagships and the Kogan Creek Solar Boost project, that may have been successful if they were better managed in retrospect. Australia's lack of success in CSP can be compared to the very successful wind and PV sectors. In these cases, the local industry is built on joining with global efforts. Wind turbines and PV panels come from global suppliers supported by local participants in the value chain. Wind and PV Industry growth was fundamentally linked to the RET providing the market signal that allows project developers to secure off take agreements and then raise the capital required for construction.

6. CSP POWER STATION PERFORMANCE AND REQUIREMENTS

The experience with internationally completed CSP power stations allows some indicative observations on issues such as water, land, construction time and personnel requirements to be made.

6.1. Solar Resource

Regarding location, there are various issues that would determine a preferred site choice. The level of solar Direct Normal Irradiation (DNI) resource is an obvious and major one. Australia has such good solar resources that it is less of an issue than most countries (Figure 47). The broad CSP industry consensus is that DNI needs to be above 2,000/kWh/m²/year. This implies that anywhere west of the great divide in Australia can be considered. It also indicates that there is considerable potential in the north of Victoria in addition to all the other mainland states.

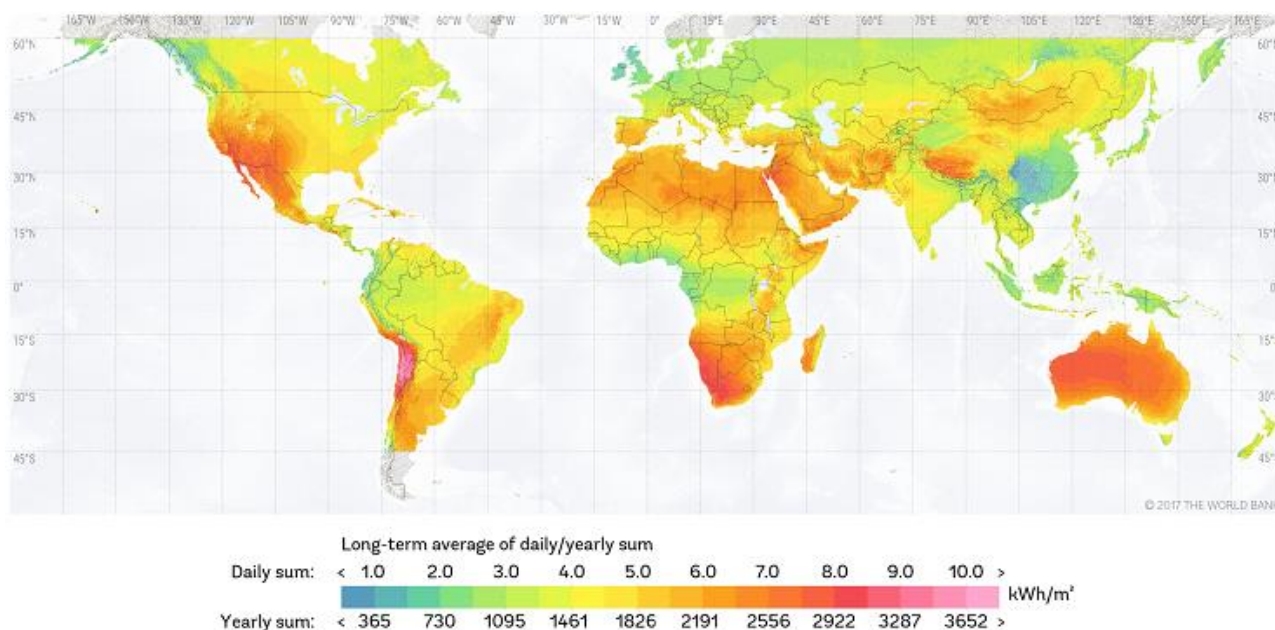


Figure 46. Direct Normal Irradiation map of the world, (© 2016 Solargis)

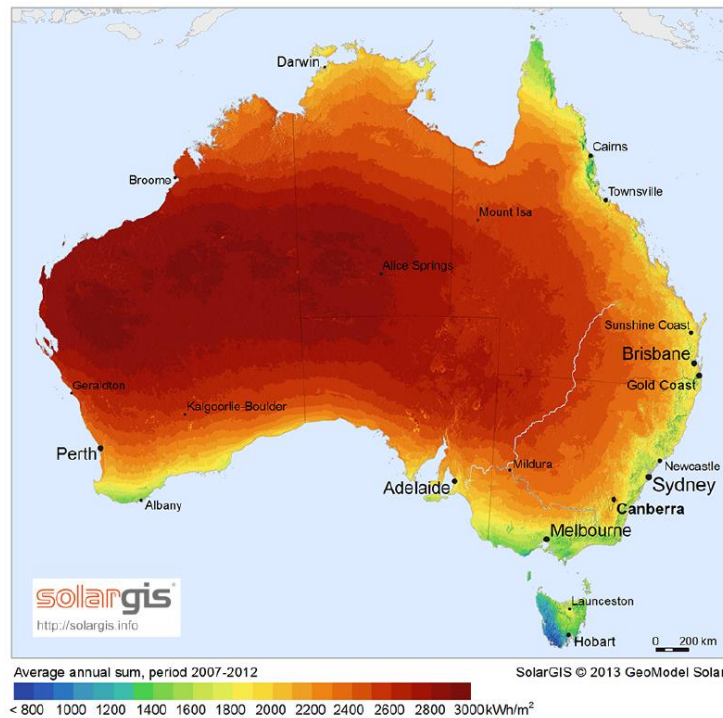


Figure 47. Direct Normal Irradiation map of of Australia, (© 2016 Solargis)

6.2. Performance of CSP Technologies

Predicting the output of CSP systems is complex. At steady state, performance is linked to the instantaneous level of DNI and also thermal losses that depend on ambient temperature and wind and cooling tower performance that also depends on ambient temperature. In addition there are finite times required for start-up procedures and thermal inertia in components that effect behaviour as inputs change. The System Advisor Model (SAM) developed by NREL, is a well-respected, publicly available tool for predicting performance (NREL, 2017b). It uses input in the form of hourly solar and weather data together with system specific physical model components to predict generation on an hour by hour basis. The SAM model has been used here in a high level examination of CSP performance issues for Australia.

The baseline for this analysis is the SAM default molten salt tower system, 100MW_e net with ten hours of storage. The baseline location, as per the 2012 study, is Longreach in Queensland, being a representative best location on the NEM with readily available solar data. Determination of LCOE for Australia is discussed in Chapter 7, here the LCOE predicted by the SAM default settings is normalised to the Longreach default plant value so that trends can be examined in a manner that is independent of precise costs and financial settings.

Solar and weather input data files have been assembled from data from the Bureau of Meteorology for a range of locations and years (Bureau of Meteorology, 2018). Best worst and

closest to average years have been identified and the closest to average year used for comparisons.

6.2.1. Optimal configurations

The Solar Multiple (SM) is an important design concept for CSP plants, a steam cycle power station with $SM = 1$ has a solar field just large enough to provide nominal turbine capacity under design point irradiation conditions, e.g. at 950 W/m^2 on the collector aperture area. Increased SM, particularly with the addition of energy storage can increase the utilization of the power block, thus increasing capacity factor, which acts to reduce the LCOE of the plant. However, increasing the SM and storage capacity also increases capital costs. This trade-off between solar field size, energy storage, and capacity factor represents an optimization problem. Figure 48, shows the impact that variation of SM and storage hours has on LCOE.

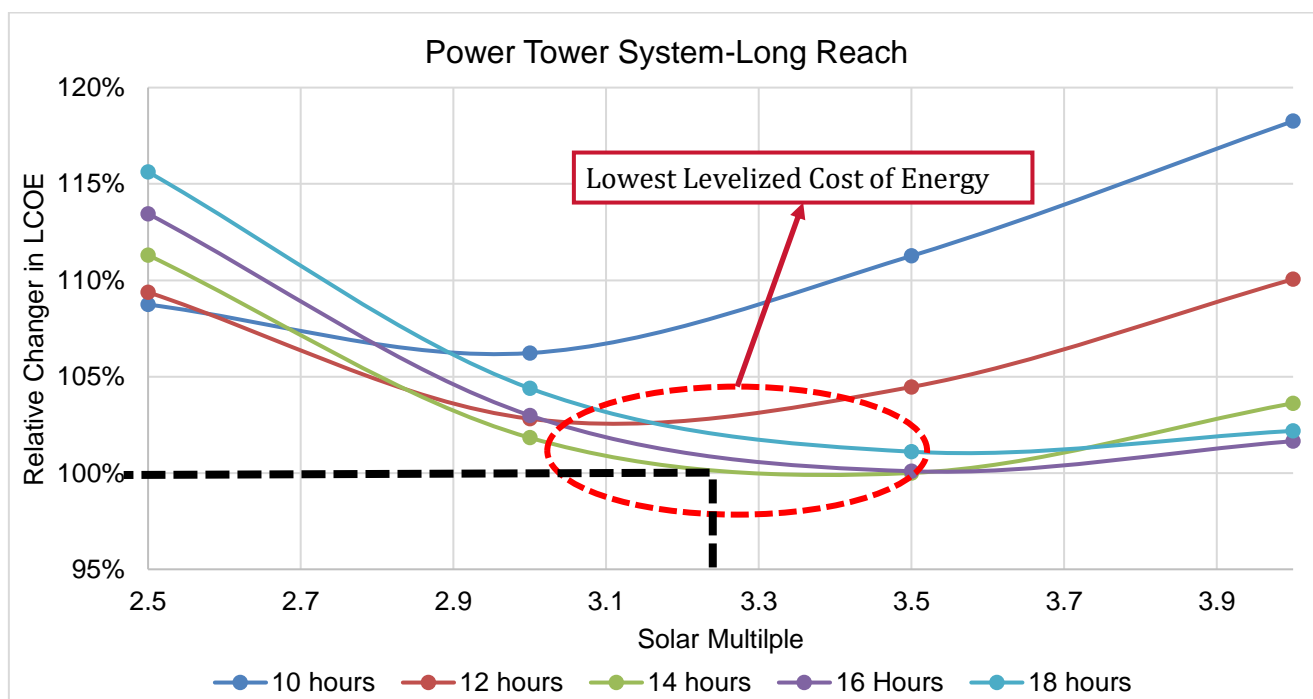


Figure 48. Relative LCOE for variation in storage hours and solar multiple for a salt tower system in Longreach Queensland.

It can be seen that lowest LCOE is obtained for a solar multiple of 3.0 to 3.5, with storage hours ranging from 14 to 18 hours. The relative change of LCOE is very low in these ranges.

A lowest LCOE system is not necessarily the economically optimal plant to build. If the main underlying driver is responding to a time varying electricity spot price (linked to the demand and supply balance), a system with reduced storage and solar multiple may be preferable as the increase in LCOE that can be deduced from this analysis may be offset by the increase in average energy sale price from limiting generation to higher value periods.

6.2.2. Performance across different sites in Australia

The performance of a tower plant across a range of sites across Australia has been analysed. The sites are shown in Figure 49 and represent sites that are representative for solar resource characteristics of sites for CSP deployment across all states. A default SAM 100MW (115 MW_g) salt power tower model with 10 hours of storage was selected for the study and the basic parameters are listed in Table 12.

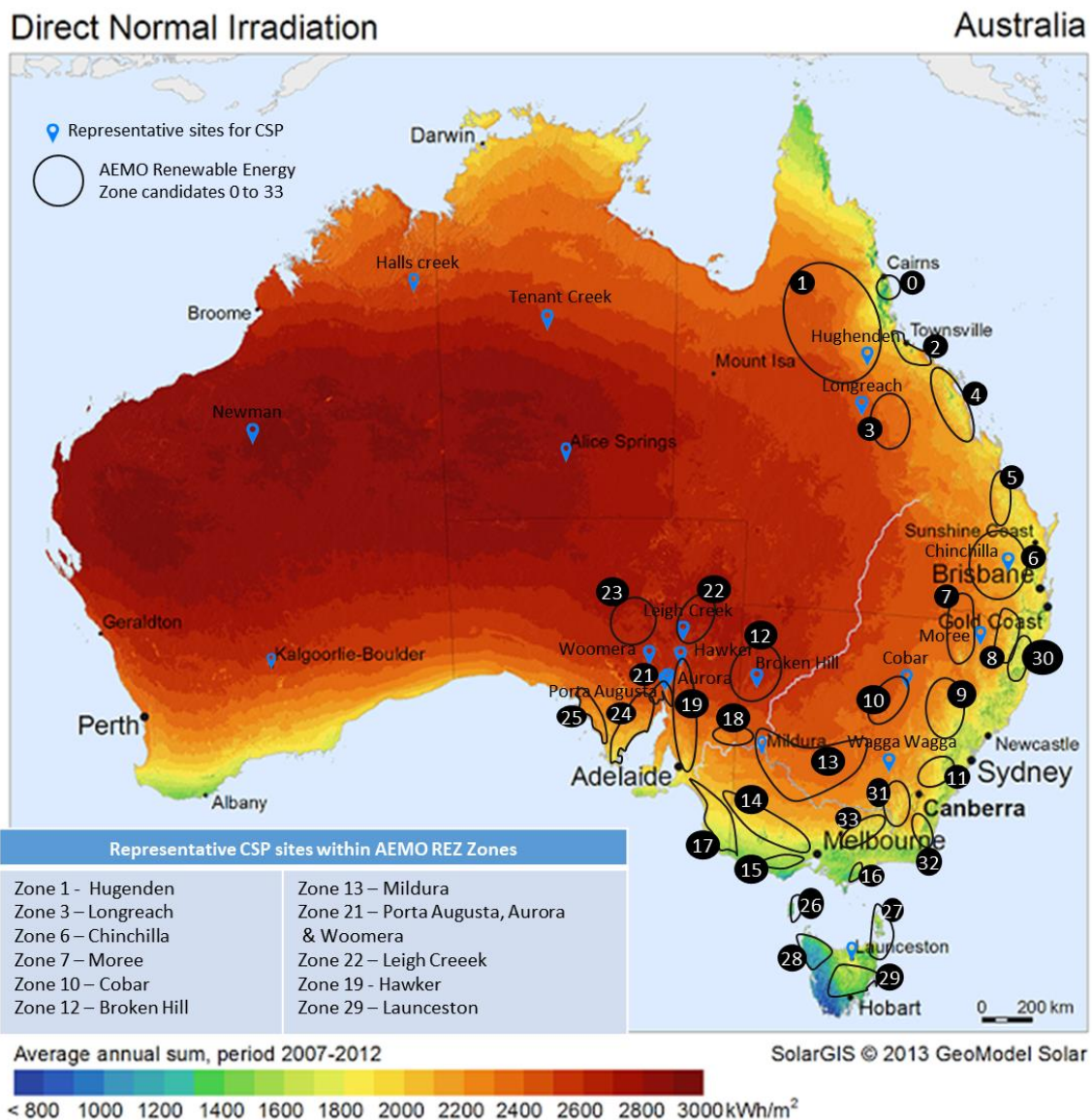


Figure 49. DNI map of Australia with representative sites for CSP plants and possible Renewable Energy Zones proposed by the AEMO indicated (AEMO, 2018).

Table 12. Default SAM case and inputs used.

Parameters	Value	Unit
Plant gross generation capacity	115	MW
Gross to net	0.9	
Net generation power	104	MW
Power cycle efficiency	0.412	
Power block Thermal power	279	MW
Solar Multiple	2.4	
Storage hours	10	Hours
Storage capacity	2,791	MWh _{th}
Receiver Thermal power	670	MW
Heliostat Area	1,261,547	m ²
Design Point DNI	950	W/m ²
Condenser type	Air cooled	

The annual energy generation and relative LCOEs for these locations are listed in Table 13 and shown in Figure 50.

In this comparison solar field size has been kept fixed to better examine the variation in generation from site to site. Testing for re-optimisation of solar multiple indicates that slightly larger mirror fields would be preferred in lower DNI sites, but the impact on LCOE is insignificant.

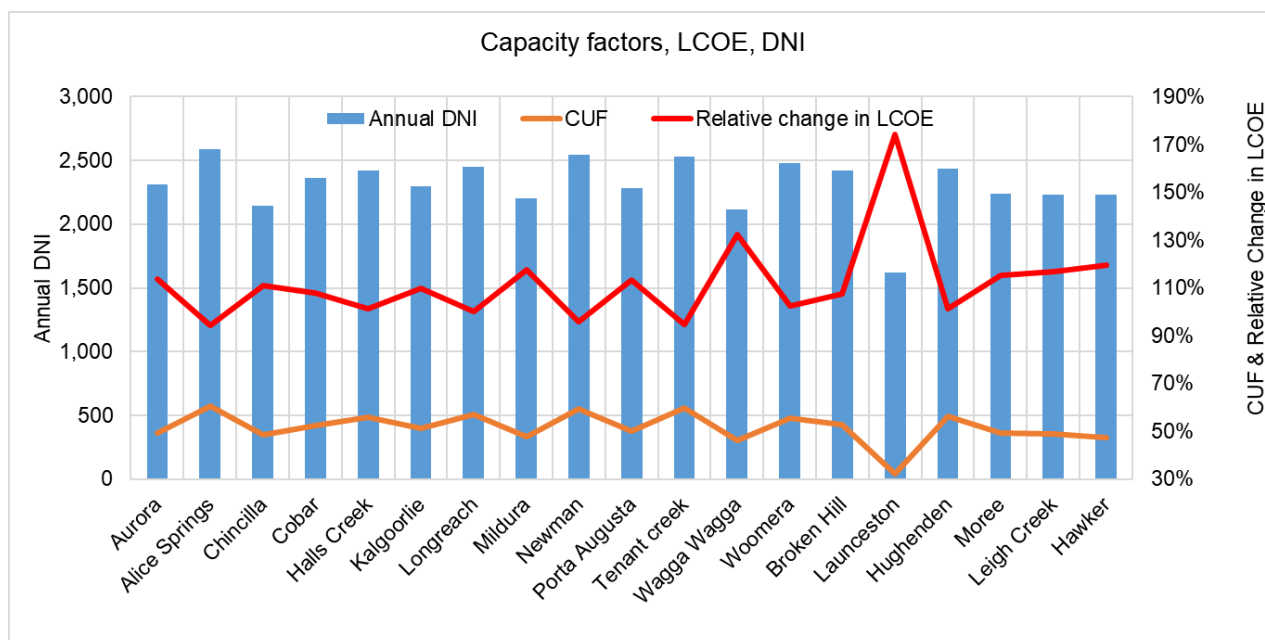


Figure 50. Annual generation, CUF and LCOE across 19 different sites during best years.

Higher average DNI gives higher annual generation and hence lower relative LCOE. These 'good' sites in Australia show variations between them of $\pm 15\%$. Tenant Creek, Newman and Alice Springs have a best average annual DNI of greater than 2,500 kWh/m²/a and outperform the

Longreach baseline. Pt Augusta and specifically the identified Aurora site shows a 15% higher LCOE than Longreach. Mildura is included as the best Victorian site, DNI is still very good by world standards, the LCOE increase over Longreach is 19%. Launceston has been included simply to test the relativity of a poor and unlikely site. It was found that technically a plant could be built and significant generation would result however at a relative LCOE of 176% it would be very unlikely that such a system would ever be contemplated.

Table 13. Closest to 22-year average Annual Generation of a Tower system across 19 different sites.

State or territory	Site	Coordinates	AEMO REZ	Annual DNI kWh/m ² /a	Annual Generation GWh/a	CUF %	Relative LCOE %
NT	Alice Springs	23.80°S, 133.89°E	n/a	2,588	548	60%	94%
NT	Tenant creek	19.64°S, 134.18°E	n/a	2,533	544	60%	95%
WA	Halls Creek	18.23°S, 127.66°E	n/a	2,420	509	56%	101%
WA	Newman	23.42°S, 119.79°E	n/a	2,544	538	59%	96%
WA	Kalgoorlie	30.79°S, 121.45°E	n/a	2,296	466	51%	110%
QLD	Longreach	23.44°S, 144.28°E	near 3	2,453	516	57%	100%
QLD	Hughenden [#]	20.85°S, 144.12°E	1	2,437	513	56%	101%
QLD	Chinchilla	26.66°S, 150.18°E	near 6	2,146	441	49%	111%
NSW	Broken Hill	31.85°S, 141.42°E	12	2,420	480	53%	108%
NSW	Cobar	31.48°S, 145.82°E	near 10	2,362	477	53%	108%
NSW	Moree [#]	29.47°S, 149.83°E	near 7	2,238	449	49%	115%
NSW	Wagga Wagga	35.16°S, 147.45°E	near 31	2,113	418	46%	132%
SA	Aurora	32.31°S, 137.63°E	21	2,314	449	49%	114%
SA	Port Augusta	32.51°S, 137.71°E	21	2,281	453	50%	113%
SA	Leigh Creek [#]	30.59°S, 138.38°E	near 22	2,232	442	49%	117%
SA	Hawker [#]	32.51°S, 137.71°E	near 19	2,234	432	48%	120%
SA	Woomera	31.16°S, 136.80°E	23	2,482	503	55%	103%
VIC	Mildura	34.24°S, 142.08°E	13	2,205	435	48%	118%
TAS	Launceston	41.54°S, 147.21°E	near 29	1,621	293	32%	174%

Note:

The above relative LCOEs are in reference to 115 MWe Power Tower Plant at Longreach with air cooled condenser.

- Locations added based on AEMO REZs (AEMO, 2018). Performance values extrapolated closest site; ratio of NASA and BOM long term average DNI used as input.

Figure 51 shows the annual energy generated vs annual average DNI directly for all sites and for best worst and closest to average years. A strong linear trend is found which also fits the points for Launceston well. There is a negative offset, meaning that a finite level of DNI would be required to achieve any generation at all. It would be expected that performance would depart from the linear trend at lower DNI's than tested. The spread around the trend reflects the behaviour of a plant in responding to solar and weather conditions that may have different characteristics but the same annual average. For example a series of days of broken cloud is likely to produce less generated energy than half clear days followed by half fully cloudy, if it results in more or less stop start cycles for the turbine.

For a particular site the variation in annual generation between best and worst years is also around $\pm 10\%$.

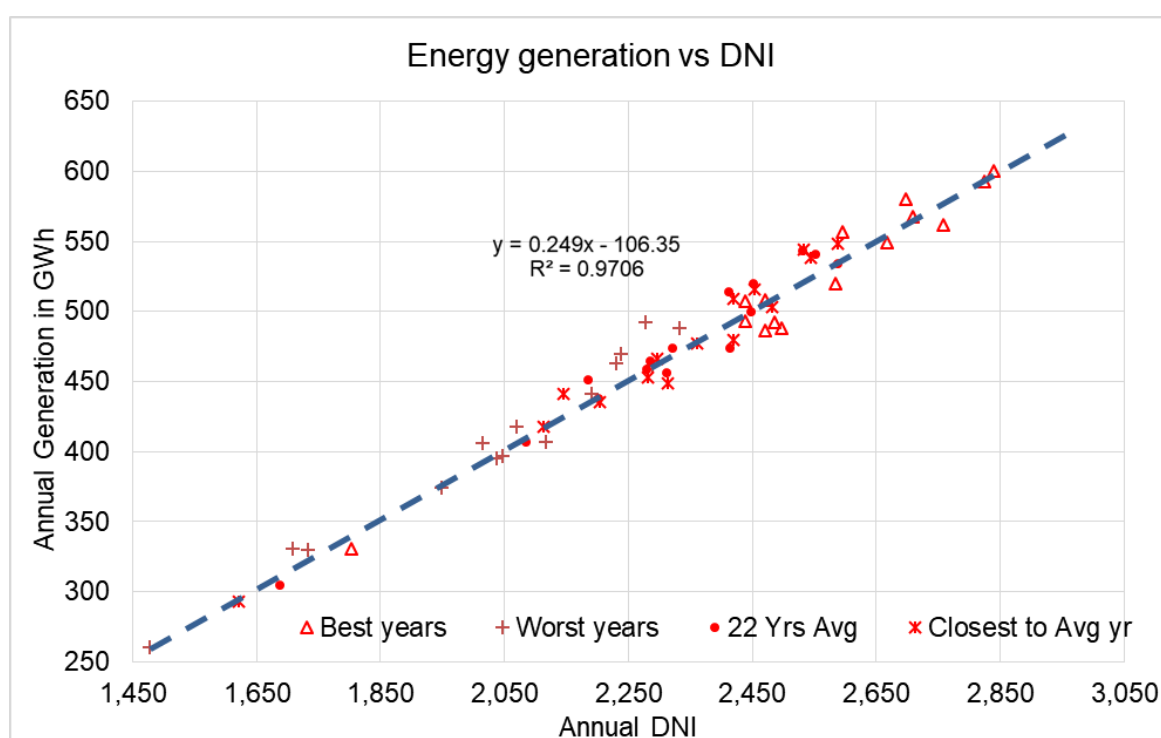


Figure 51. Annual generation across 15 different sites during worst, closest to average and best years with reference to 22-year average.

The Integrated System Plan for the National Electricity Market, published by the AEMO in July 2018 (AEMO, 2018), presents a list of 34 potential priority 'Renewable Energy Zones' for new deployment of renewable energy systems across Queensland, New South Wales, Victoria and South Australia (Figure 50). Referring back to Table 13 and Figure 49, it is apparent that those zones that are inland cover large areas with good DNI resources and are well suited to CSP developments. Specifically, in Qld, 1,3,6 and 7, in NSW 7,10,12,13 and 18, in Vic 13 and parts of 18, in SA 21,22,23 and parts of 19.

6.2.3. Technology comparison

Longreach and Mildura have been used to compare the relative performance of the different CSP technologies. Default SAM models were used to simulate plants of similar capacities. The solar multiple was optimized using parametric study as per section 6.2.1. Although each technology would have different solar multiples, storage hours to achieve it's best LCOE we have compared all CSP technologies with 10 hours of storage and only optimised solar multiple. Both dry and wet cooling systems have been modelled to study the outcome of water consumption.

SAM has default models for Salt Towers, Troughs with oil HTF coupled to salt storage, Troughs with direct salt heating and LFR with direct salt heating. However SAM doesn't have a dedicated parabolic dish system with thermal storage so a proxy calculation for a dish system has been included for comparison. The Sam Dish Stirling model was used to determine the dish area needed to provide the same thermal input to storage as the tower model and the remainder of the system was assumed to be the same as tower system. This mirror area was used to estimate the approximate cost of the plant and the LCOE. The cost of solar field mirrors per unit area was assumed twice that of a Trough plant, to allow for the greater complexity of construction.

Table 14 provides the results of the comparison of CSP technologies with 10 hours of storage for Longreach and Figure 52 illustrates the behaviour across the year.

Comparing the tower with trough and LFR options, it is apparent that it generates with the highest capacity factor and that this flows through to a lower LCOE when the SAM default cost parameters are used. The comparison is most striking when comparing a salt tower system with a trough system that uses oil based HTF, which is the industry dominant configuration. The trough system modelled with direct use of salt as HTF shows better performance in terms of energy generated and reduced LCOE, this is the consequence of the higher temperature it is able to achieve in the HTF return. It makes power generation more efficient and storage more cost effective. There is also a cost saving in avoiding a HTF oil loop. Such direct salt heating trough systems have as yet only been built at a demonstration level, they face considerable technical challenges to avoid salt freezing in the pipe network during off sun periods. Nonetheless the potential benefit is apparent. LFR systems have also been piloted with direct salt heating and since the receiver is stationary the freezing problem may be more manageable.

On this analysis, the variation between tower, trough and Fresnel in terms of LCOE is only between 10 – 20%. This is within the inaccuracy of the comparative cost parameters used. It should be concluded that the 'race' is still wide open. Individual manufacturers certainly aspire to installed cost reductions that can bring their own approaches down by such margins.

Table 14. Comparison of CSP technologies for technologies with 10 hours storage for Longreach, 2009 (closest to 22 year average)

Comparison of CSP Technology – Longreach						
Parameter	Unit	Tower	Trough (oil)	LFR	Trough (salt)	Parabolic Dish
Plant capacity - Gross	MW	115	111	115	111	115
Heat Transfer Medium		Hitec salt	Therminol oil	Hitec salt	Hitec salt	Hitec salt
HTF supply temperature	°C	574	391	525	550	574*
HTF return temperature	°C	290	293	293	293	290*
Net Energy generated Dry /(Wet) cooling	GWh/a	547 (572)	480 (519)	498 (525)	508 (545)	547*
CUF Dry /(Wet) cooling	%	60.3 (63.1)	54.9 (59.3)	54.9 (57.9)	58.1 (62.3)	60.3*
Mirror Area	×1000 m ²	1,388	1,321	1,776	1,354	846 ^
Land Area	km ²	3.24	1.95	1.15	2.00	0.85^
Water consumption Dry /(Wet) cooling	×1000 m ³ /a	101 (1,545)	111 (1,866)	45 (1,482)	98 (1,527)	58 (1,487) ‡
Relative LCOE Dry /(Wet) cooling	%	100 (95.7)	126.3 (117.3)	117 (111.3)	114 (106.6)	87 (83.7) ‡

* Assumption, ^Estimated using SAM dish Stirling system, ‡ Estimated

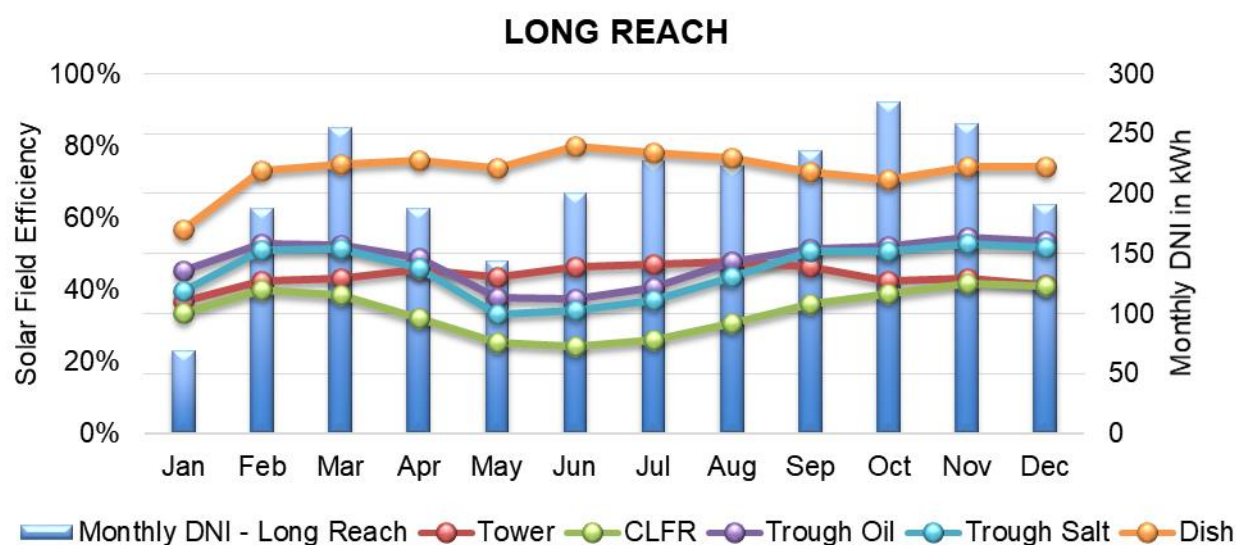


Figure 52. Comparison monthly solar field efficiency of various CSP technologies-Long Reach

In Figure 52 , performance is compared via solar field efficiency and monthly DNI. The month to month variation in DNI at Longreach is considerable for a given year but does not have a strong seasonal trend. Efficiencies drop as DNI drops as fixed and parasitic losses form a higher fraction of generated energy. For the linear concentrators there is a trend to lower efficiency in mid-year in correlation with a lower midday sun elevation that reduces the total energy intercepted for a single axis tracking devise.

Table 15 and Figure 53 show a similar comparison for Mildura. Similar conclusions can be drawn however the seasonal impact on DNI and midday sun elevation is much more pronounced in Mildura's southern location. This is seen to disadvantage the two axis tracking tower and dish systems much less than the linear concentrators so improving their position in terms of greater annual generation and lower LCOE.

Table 15. Comparison of CSP technologies with 10 hours storage for Mildura, 2013 (closest to 22 year average)

Comparison of CSP Technology – Mildura						
Parameter	Unit	Tower	Trough (oil)	CLFR	Trough (salt)	Parabolic Dish
Plant capacity - Gross	MW	115	111	115	111	115
Heat Transfer Medium		Hitec	Therminol	Hitec	Hitec	Hitec
HTF supply temperature	°C	574	391	525	550	574*
HTF return temperature	°C	290	293	293	293	290*
Net Energy generated Dry /(Wet) cooling	GWh/a	462 (476)	390 (418)	406 (422)	412 (438)	462 (476) *
CUF Dry /(Wet) cooling	%	50.9 (52.5)	44.6 (47.7)	44.8 (46.6)	47.1 (50)	50.9 (52.5) *
Mirror Area	x1000 m2	1,388	1,321	1,776	1,354	846^
Land Area	Hectare	755	483	284	495	209^
Water consumption Dry /(Wet) cooling	x1000 M3/a	95 (1,278)	101 (1,504)	38 (1,202)	90.8 (1,232)	60 (1,489) ‡
Relative LCOE Dry /(Wet) cooling	%	118.1 (114.2)	154.3 (144.5)	142.7 (137.3)	139.8 (131.7)	108 (104.7)

* Assumption, ^Estimated using SAM dish Stirling system, ‡ Estimated, ~Approximate

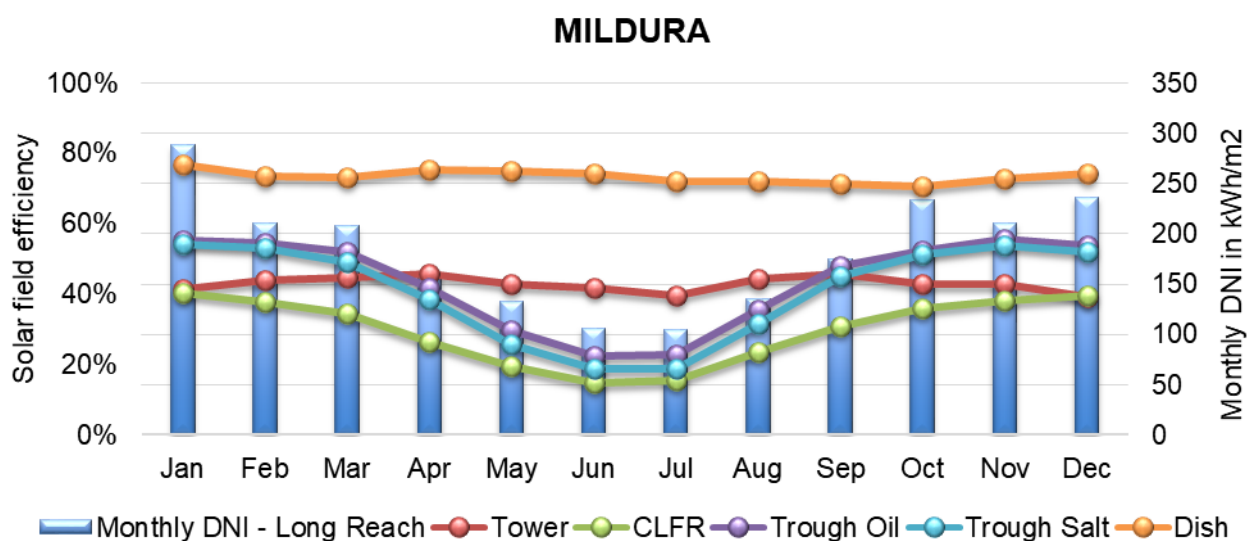


Figure 53. Comparison of monthly solar field efficiency of various CSP technologies-Mildura.

6.3. Environmental considerations

Generally speaking, the environmental issues associated with CSP plants are straight forward and routinely dealt with. Site choice is restricted to locations with good solar DNI, sufficient land available for large scale plants and water availability. Issues of risks of heat transfer fluid oil leakage (for troughs), tower visual impact and water usage are all important but routinely dealt with in projects around the world.

Experienced CSP global project developers report the issues needing consideration in environmental impact assessments. These include:

- Cataloguing the environmental situation before construction of the project
- Classification of land according to zoning and land development plans
- Assessment of the local socio-economic environment
- Cultural, historic and archaeological values
- Fauna and vegetation found on the site and surroundings
- Hydro-geological situation and water quality
- Site noise measurement.

Many of the world's existing plants, particularly trough plants, have as part of construction a complete levelling of the site with removal of all vegetation. This would be a major impact in a sensitive area. However, there are approaches for heliostat fields in particular, that can see the solar field installed with minimal impact to vegetation and fauna. These include keeping vehicles to defined tracks and driving piles for heliostat foundations without removing vegetation.

The impact by the construction and operation of CSP plants on the habitat of local fauna is best assessed and dealt with during initial site assessment and any fauna can be relocated or the project location be shifted, to minimize costly delays during construction. For example, the Ivanpah project in the Californian Mojave Desert experienced delays and additional costs due to its suspected impact on the habitat of endangered desert tortoises at the location of the plant.

The issue of bird deaths has been raised at the large tower projects in the US. It is argued that following proper investigation and improved management of mirror fields, deaths are at a level commensurate with bird strike deaths on all man-made structures. Claims that bird deaths are greater than the collected carcasses indicate because they are completely incinerated in the focal region have been tested experimentally at Sandia Labs. It is found not to be the case, even the highest concentration of radiation encountered can not obliterate a bird's body as it falls. The occasional flashes and puffs of smoke observed at such plants are in fact small insects being caught in the focus.

6.4. Water use

Typically, large coal fired power stations with wet cooling consume around 3 kilolitres per MWh.

Similarly, water is required for CSP plants for:

- condenser cooling,
- make-up for steam/condensate cycle,
- collector cleaning, and
- other general purposes including, fire fighting, staff use and general services.

Of these, condenser cooling when evaporative (wet) cooling towers are employed, is by far the largest water consumer.

Many existing CSP plants use evaporative cooling towers where low cost water is available. Water requirements for trough and Fresnel plants that employ wet cooling towers are estimated to be approximately 3 kilolitres / MWh, while higher conversion efficiency tower plants are estimated to use less at about 2 kilolitres / MWh (IEA, 2010).

It is feasible to use dry-cooling to reduce water consumption in arid regions. There are now several CSP plants that use air cooled condensers and this is likely to be a preferred approach in Australia. However, this results in a decrease in electricity production from a trough plant by an estimated 7% and increases the cost of the electricity by about 10%.

Table 16 indicates water use with wet and dry cooling for a conventional steam combined-cycle gas turbine, and for parabolic trough solar power plants. The water use for conventional plants is based on a California Energy Commission report. The water use for the parabolic trough plants is based on data from the SEGS plants operating in the Mojave Desert.

These numbers are consistent with the predictions from the SAM models presented in section 6.2.3.

Table 16: Water Requirements for Power Generation (reproduced from NREL with original figures converted to litres per MWh of Plant Output (Bracken et al., 2015)).

Plant Type	Steam Condensing	Auxiliary Cooling and Other Load	Total litres / MWh
Stand-alone steam plant	2,725 ⁽¹⁾	114 ⁽²⁾	2,839
Simple-cycle gas turbine	0	568 ⁽³⁾	568
Combined-cycle plant (2/3 GT + 1/3 steam)	908 (1/3 x 2725)	416 (2/3 x 150 + 1/3 x 30)	1,325
Combined-cycle plant with dry cooling	0	416	416
Stand-alone steam plant with dry cooling	0	114	114
Parabolic Trough with wet cooling	3,483 ⁽⁴⁾	303 ⁽⁵⁾	3,785
Parabolic Trough with dry cooling	0	303	303

Notes

- (1) Evaporation + blowdown = 12 gpm / MW (45 lpm / MW).
- (2) Estimated at ~5% of evaporation + blowdown.
- (3) Mid-range of 284 to 757 l / MWh for turbine cooling, emissions control and other load.
- (4) Based on historical data from SEGS (higher than conventional because of lower net steam cycle efficiency of SEGS, in part due to HTF pumping and night time parasitics).
- (5) Includes make-up water requirements for steam cycle (227 l / MWh) and solar field mirror wash (227 l / MWh) data from KJCOC.

6.5. Land area

CSP plants occupy similar amounts of land per generated energy as large scale PV plants. Whilst these areas are large, even if a large fraction of the nation's electricity were provided by CSP, the amount of land is negligible in the semi-arid farm land environments likely to be preferred. Increasingly consideration is given to allowing activities such as grazing to continue within mirror fields.

Care needs to be taken when interpreting land area data as some reports refer to collector area rather than land area. The German Aerospace Centre has reported that a 30% land use factor¹⁴ for existing trough plants is typical (DLR, 2005) as the spacing of rows needs to ensure that shading is minimised.

¹⁴ Meaning that the collector area is 30% of the land area.

Considering some specific examples; the Solnova 50 MW_e trough plant consists of 300,000m² of collector spread over 120 hectares (2.4 ha / MW). Similarly, the Alvarado 1 plant, near Badajoz in the Extremadura region of Spain, has a capacity of 50 MW_e and uses parabolic trough technology, with over 184,000 mirrors on a 130 hectare site (2.6 ha / MW).

Incorporating storage requires an increase in the size of the collector field and some land for the storage components. For example, the 50 MW_e Andasol plants with 7.5 hours of storage have a gross electricity output of around 180 GWh per year and a collector surface area of over 510,000m² spread over 200 hectares, (4 ha / MW). These plants operate at a higher capacity factor than those without storage and highlight the requirement to consider capacity factor and be cautious when comparing plants on a 'per MW' powerblock rating basis.

Brightsource's Ivanpah solar tower project (which does not include a separate storage component) consists of 3 towers with heliostat fields for a total of 392 MW_e on 1,457 hectares, (3.7 ha / MW).

Using the default SAM models in a typical Australian location give the results in Table 17. It is the land area per MW_{th} of the solar field that is the most constant metric. It does vary between the technologies but will be applicable for a particular technology almost universally. As hours of storage are increased and the Solar Multiple is also increased the land areas per MW_e is seen to increase in proportion.

Table 17. Land Area for CSP Technologies based on SAM.

Description	Land area for CSP Technology – ~2,400 kWh/m ² /year			
	Power Tower	Parabolic Trough	CLFR	Parabolic Dish [^]
Hectares per MW_{th}	1.0	0.53	0.29	0.27
Hectares per MW_e				
No Storage	5.0	2.2	1.4	1.1
4 hours	6.2	3.0	2.0	1.4
6 hours	6.4	3.2	2.1	1.5
8 Hours	6.6	3.6	2.3	1.7
12 Hours	7.4	4.5	2.6	2.0
16 Hours	9.5	5.2	3.2	2.2
20 Hours	10.4	5.8	3.3	2.5

[^] Approximate Estimates based on SAM Dish Stirling

Though Tower Systems have better capacity factor and lowest LCOE of the commercially mature approaches, it requires more land area due to its complex arrangement of Heliostat mirrors around the tower to avoid shading and blocking losses. In terms land area LFR is the most compact plant. Land area is unlikely to be a major issue in Australia, however there will be occasions when it could be an important consideration. Further to that heliostat field are circular whereas the other technologies can be fitted to an available allotment of any reasonable shape in the same way that large PV systems are.

6.6. Staffing levels

There is a wide range of forecasts for staffing levels when developing and operating CSP plants and it varies depending on the country. Furthermore there will be significant variations depending on the system size, technology type and local supply chains and logistics. There is publicly available data from CSP plants developed in the US over the last few years that provides a good overview for different technology types including solar tower and parabolic trough and sizes ranging between 50-390MW.

Using Estela and ESMAP references (ESMAP, 2018; ESTELA, 2018) an assessment has been undertaken comparing the jobs created during the construction and operation phase for the different CSP plants (see Table 18).

Table 18: Jobs created by various past CSP projects.

Plant	Year & Technology (start of operation)*	Plant Capacity (MW)	O&M (Total Jobs)	Construction Jobs (Total Jobs)	O&M Jobs (Jobs/MW)	Construction Jobs (Jobs/MW)
ESMAP Estimate	2011 / PT & ST	50	125	500	2.50	10.00
Crescent Dunes	2014 / ST	110	45	600	0.41	5.45
Mojave	2014 / PT & ST	250	70	830	0.28	3.32
Solana	2013 / PT	250	60	1700	0.24	6.80
Genesis	2014 / PT	250	50	800	0.20	3.20
Ivanpah	2014 / ST	392	80	1000	0.20	2.55

*Note: Solar tower = ST; Parabolic Trough = PT

Table 19: CSP plant staffing levels, reproduced from ESMAP.

Staffing Developed Countries (e.g. U.S., Europe) For SF size = 500,000 m ² OH rate								
		Nominal #	Reduced #	Level	Rate, USD\$/yr Direct	35% Burdened	Annual USD\$/k Nominal	Reduced
Solar Field Manager		1	0	Senior	50	67.5	67.5	0.0
Maintenance	Supervisor	1	1	Skilled	45	60.8	60.8	60.8
2 shifts	Welder	1	1	Skilled	40	54	108	54.0
(4 10h days)	Mech Tech	2	1	Exper'd	35	47.3	189	47.3
	I&E Tech	1	1	Skilled	40	54	108	54.0
Lead Mirror	Wash Supervisor	1	1	Skilled	45	60.8	60.8	60.8
1 shift	Equip. Ops.	4	2	Exper'd	35	47.3	189	94.5
Field Operator (status)		5	3	Exper'd	30	40.5	202.5	121.5
		20	13			Total	985.5	492.8

In Figure 54, the plant construction and operation jobs have been simultaneously plotted. Observing the orange and blue trend-lines it can be recognised how the scale efficiencies impact the job creation potential as the plant capacity increases. The scale efficiency effects are more notable for the construction employment than for the operation. The employee needs for each capacity doubling reduce on average by 11.2% for the operation activities and by 17.7% for the construction jobs.

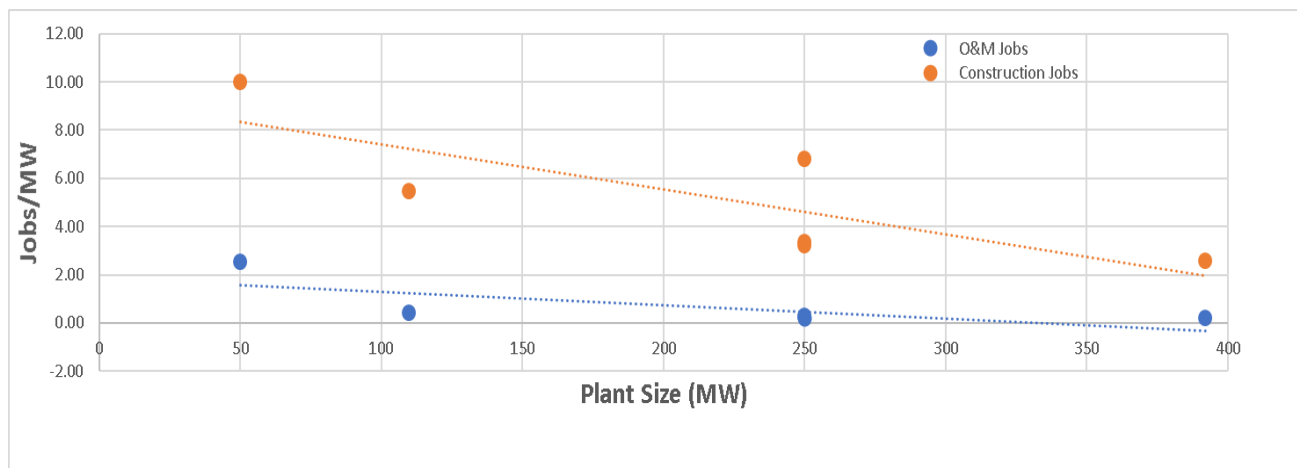


Figure 54: Construction and O&M jobs created depending on plant size.

6.7. Construction time

During the height of construction in Spain, typical 50MW_e trough plants took was 18 months from ground breaking to connection. First of a kind projects that represent new technology configurations typically take up to twice as long as this and also have much more extended commissioning and de-bugging phases.

In addition to this, proponents need to factor in the time required for approvals and to reach financial closure, which can be extensive. Figure 55 gives an indicative timeline for a 150 MW_e trough plant example project time line from Aries for the Ouarzazate project (2012).

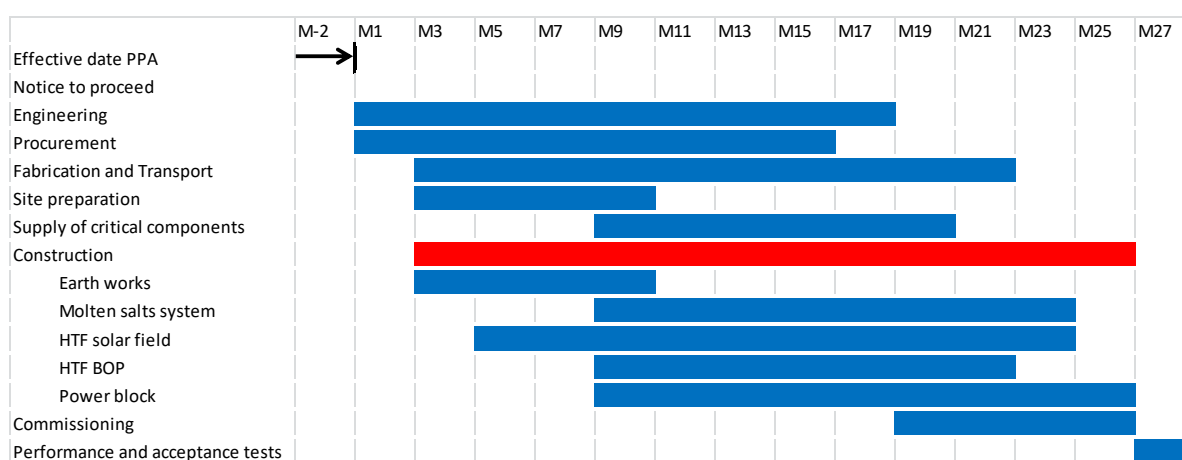


Figure 55. Representative CSP project timeline for a 150 MW_e plant (redrawn from Aries for the Ouarzazate project (Perez, 2012)).

7. COST OF CSP ENERGY IN AUSTRALIA

7.1. Levelised Cost of Energy

A key metric in considering the economic performance of any energy technology is the Levelised Cost of Energy (LCOE) generated. This is calculated from estimated capital costs plus ongoing cost of inputs (O&M, fuels, cost of capital and other variable inputs) as discussed in detail in Appendix A. For CSP, the initial capital cost dominates the forecast.

The installed cost per MW is a commonly discussed parameter. However, great care needs to be taken in making comparisons as it is actually the installed cost per MW divided by the capacity factor that influences the viability of a proposal. Most CSP plant now incorporate some amount of energy storage. Storage is usually used to run a generator for a longer time with a greater amount of collected energy. In this case, installed cost per MW will be higher but the annual capacity factor will also be higher.

In this study we also contemplate the possibility of using storage to run a larger power block for a shorter time, a choice that will decrease the capacity factor and increase the LCOE but potentially lead to higher income.

It is misleading to translate costs between projects in different countries and years simplistically based on exchange rates. Whilst the cost of many input commodities may be global and can be converted in this way, the cost of manufacturing labour and other inputs, are country specific.

Going beyond this, it should be noted that, the first major projects in a country which is new to the technology will incur extra costs as the capability and supporting manufacturing infrastructure is established for the first time. Identifying appropriate escalation rates to allow past project costs to be compared to the present is also difficult.

7.2. Cost Structure

Establishing a cost model for CSP in Australia is challenging for two reasons. Firstly cost data for CSP globally is hard to access as the industry is characterised by a relatively small number of large projects in any given year. These alternate between countries and between sub-technologies and supplier consortia. All these projects routinely treat installed cost data as commercial in confidence although various details, such as PPA prices tend to become public. Added to that is the challenge that there is no complete utility scale system yet in Australia.

ITP previously carried out a comprehensive study on the potential for CSP in Australia (Lovegrove et al., 2012). This study compiled all globally available public cost data supplemented with some key confidential inputs from major players in the field. This was normalised and averaged and then deconstructed to assemble a subsystem based cost model.

Subsequent to that the technology neutral cost model was used to produce a set of technology specific cost inputs for the well known NREL System Advisor Model (SAM). In doing so this highlighted a newly emerging view that a Tower system with direct salt heating and significant hours of energy storage offered the lowest LCOE. This industry view has strengthened over time and for the present study a salt tower system is adopted as the proxy that establishes the current baseline cost for CSP.

More recently, ITP has carried out extensive analysis of salt tower costs for Abengoa (Lovegrove et al., 2015). Abengoa carried out a detailed bottom up engineering study of a first pilot scale 20MW_e salt tower plant sited at Perenjori in WA. As such it is probably the most detailed specific cost CSP estimation study that has been carried out for Australia. ITP's work took the Perenjori study results and scaled it to a full sized *n*th-of-a-kind system.

7.2.1. Update for 2017- 2018

To develop an updated cost model six additional external sources of information have been accessed as follows:

- IRENA (IRENA, 2017) have produced a comprehensive study that offers installed cost data in a globally generic manner for all the key renewable energy technologies including CSP. They represent a reputable source and have presumably surveyed industry sources in a reasonably comprehensive manner. The extent to which they have captured a correct and up to date view is not entirely apparent.
- NREL (NREL, 2017c) have also produced a comprehensive data set on costs. They also represent a reputable source and have presumably surveyed industry sources in a reasonably comprehensive manner. Again the extent to which they have captured a correct and up to date view is not entirely apparent.
- SolarReserve have publicly revealed a capital cost (\$650m) and predicted annual generation (495GWh) for their Aurora 135MW salt tower system planned for Pt Augusta in South Australia. This represents the most up to date and directly relevant cost data point available for Australia. The project does not yet have financial close so the cost prediction carries this level of doubt. Ultimately only project completion on budget will completely confirm it.
- CO2 CRC have published the Australian Power Generation Technology Report (CO2CRC et al., 2015). This includes cost data for CSP and is in wide circulation as a definitive source in Australia. It does appear to be largely based on a conservative view based on interpretation of older published data sources and so effectively lags behind its published data. It is also now two years old.
- Price (Price, 2017) has recently published a US based study that involved detailed bottom up cost estimation of a tower plus salt system carried out by Sergeant and Lundy. This is a

strong and recent data point for US conditions. It can be assessed as being likely more conservative than the price that might be offered by an OEM under an aggressive bidding environment.

- The NREL System Advisor Model (Blair et al., 2014) contains cost calculations within its default models for technology configurations including tower with molten salt. NREL attempts to update these according to their understanding of industry status. Whilst they may lag actual achievable costs to some degree, their model is particularly useful for understanding the relationship of installed cost to plant configuration.
- ARENA's CSP RFI elicited 30 responses including from a range of experienced players two of these offered a view on installed costs and many offered a view on LCOE.

The model developed for CSP for this project is made up as:

- A coefficient that determines the cost of the solar field plus tower plus receiver on a \$/MW basis. Subject to a power law size scaling
- A coefficient that determines the installed cost of the thermal storage system on a \$/MWh basis¹⁵ subject to a power law size scaling.
- A coefficient that determines the cost of the Power block and all balance of plant on a \$/MW basis subject to power law size scaling

In assessing this data, the highest weightings were applied to the SolarReserve announced cost and the RFI responses. The final results are given in Table 20.

These costing factors give a cost 'to the plant gate', it includes all site works and connection costs to grid, but does not include any significant extension of grid or water / gas supply. It also does not include any allowance for the cost of finance during construction. This costing assumes the same level of industry maturity as is currently the case in the USA, a margin of a further 15 to 20% would likely apply for a "first of a kind" system in Australia. It also does not take into account variations in regional construction cost indices.

¹⁵ Note this is not to be confused with a Levelised Cost of Energy which is also quoted in the same units.

Table 20. Concentrating Solar cost model parameters

	Specific Installed cost	baseline capacity	Power law size exponent	Life-time	Fixed O&M cost	Efficiency	deployment growth
	m\$/MW	MW		year	%/yr		%/yr
Solar Field including receivers and towers as appropriate	\$0.46m/MW _{th}	600MW _t	0.9	30	2%	-	20%
Storage system	\$26,000/MWh _{th}	1429MWh _{th}	0.8	30	2%	100%	20%
Final conversion including power block boiler heat exchangers and other BOP	\$2.40m/MW _e	100MW _e	0.7	30	2%	42%	20%

These numbers are only accurate to an estimated $\pm 20\%$

It must be emphasised that this is a rule of thumb approach designed to inform policy making in a situation where consistent cost information is difficult to obtain. These numbers should not be used in lieu of direct cost estimates for specific projects.

In this simplified cost model, all indirect costs have been allocated pro-rata to the physical subsystems. Overall, indirect costs account for 25% of the total cost and could be represented as a separate category with the subsystem cost factors each reduced by a compensating amount.

This cost model is constructed around the baseline assumption of a large molten salt tower system. It is presented in a technology neutral manner however. The presentation of solar field costs as \$/MW_{th} rather than \$/m² gives a value that can be taken as representative of CSP overall. The value for final conversion can also be taken as representative for all CSP types, the final conversion efficiency however varies with steam temperature and system size.

In this analysis, the costing of storage is based on the current industry standard of a two tank molten salt system. The technology applied to trough and tower plants in this regard is essentially the same. There is a key difference however, since the thermal capacity achieved by heating a substance (ie the molten salt) is proportional to the temperature increment. Tower systems achieve a much higher temperature boost between hot and cold tanks and so store more energy in the same volume.

Thus the rule of thumb costing for storage is adjusted to:

$$\text{Thermal Storage System cost coefficient} = (284/(T_h - T_c)) \times \$26,000/\text{MWh}_{th}$$

Thus an oil HTF trough system with a temperature difference reduced to 98°C between hot and cold tanks, will face a storage cost of \$75,300/MWh_{th}, illustrating a key advantage of the tower approach at the present time.

In discussing the costs of a new energy technology from a policy and planning perspective, reference is often made to the concept of an Nth of a kind (NOAK) system. This is intended to indicate that some number of systems (e.g. $N < 3 - 5$) have been built such that construction teams and supply chains have developed experience and overcome initial inefficiencies. This level of costing marks the start of a further long term cost reduction trajectory that will fit a learning curve model as discussed later. In contrast to NOAK is the cost of a first of a kind (FOAK) system a margin of a further 15 to 20% would likely apply for a first of a kind system in Australia.

7.2.2. Operation and maintenance costs

A significant contributor to cost of energy is the cost of Operation and Maintenance. Much of this is labour related. O&M costs include but are not limited to:

- Mirror field cleaning
- Water and other inputs
- Control room staff
- General plant maintenance
- Replacement of breakages.

These costs can be categorised as a mixture of variable costs that are in proportion to energy sent out and fixed costs that are incurred irrespective of levels of generation.

AT Kearney (2010) suggest a typical 50 MW_e Spanish plant has a total of 47 full-time equivalent jobs per year during operation (AT Kearney, 2010). Podewils (2008) notes that Andasol 1 has 40 people, with O&M costs of 0.072 Euro/kWh and suggests a 250 MW CSP system could cut O&M costs to 0.02 Euro/kWh (Podewils, 2008). Kolb et al (2011) quote a 2013 O&M contribution to LCOE of 1.8c/kWh out of a 15c/kWh total, dropping to 1.3c/kWh in 2017 and 1.1c/kWh in 2020. Kutscher et al (2010) have for trough systems, fixed O&M costs for a 100-MW plant in southwest Arizona of \$8,500,000 / annum or USD\$70/kW-yr. In addition, variable O&M costs (for utilities and water) were estimated at USD\$2.5/MWh. Further; *“Total O&M costs equate to about 1.5¢/kWh. This cost is consistent with the most recent data from the SEGS plants”*.

For ITP’s 2012 study a simplifying assumption of treating all O&M costs as variable at a rate of AUD 0.015/kWh for a 100 MW_e 40% capacity factor plant, has been adopted.

In this study the alternative approach of treating all O&M as fixed at 2%/a of capital cost has been adopted. The main consequence of this is that where learning curve model of costs over time is

considered, O&M costs will also reduce in proportion. This value is assumed for a 100MW+ system size, it is apparent that it is likely to be higher for smaller systems.

7.2.3. Plant size effects

The size of a system significantly affects the capital cost per installed capacity. ITP's 2012 study reviewed the literature on the subject and assembled a systematic basis for scaling capital costs with size that remains consistent with industry views¹⁶ and is used here.

There are three key effects:

1. For components / subsystems which are essentially single units of varying size per plant, larger units for larger plants will be more cost effective per MW of plant capacity.
2. The efficiency of turbines falls off in a non-linear manner as size is reduced; this means that all subsystems on the thermal side of the power block must be increased in proportion to the conversion efficiency reduction.
3. Indirect costs. The indirect costs for a 20MW system are almost the same as for a 100MW system, e.g. development costs, mobilization, engineering, management, supervisions, etc.

For direct size effects on equipment costs empirical power law relationships are well established. Reference was made to Sargent and Lundy (2003) report that the specific cost per unit of installed capacity of both the Power Block and the Balance of Plant (BOP), have a power law scaling with size as follows:

$$\text{BOP Cost/kW}_e \sim (\text{System Size})^{(-0.1896)}$$

$$\text{Power Block Cost/kW}_e \sim (\text{System Size})^{(-0.3145)}$$

These exponents are consistent with the power law for BOP and Power Block combined of 0.7 listed in Table 20, considering that the Power Block is the significantly larger component of the two (note that the power law exponent for unit costs equals exponent-1 for absolute costs).

Power Block and BOP are assumed to scale completely according to the power law relationship. For the others, an estimate has been made on the extent to which modularity could be assumed. In the case of thermal storage, the value of 0.55 used for the 2012 study is based on an assumption that the salt inventory was 45% of the total cost and fixed in price per unit. Abengoa's experience suggests that salt cost per unit also depends on volume, so the overall fraction that is scaled with size has been increased to 1.

¹⁶ AT Kearney (2010) reports that companies surveyed estimated a 15% reduction in the cost per MW installed if the size of the plant were 100 MW instead of 50 MW.

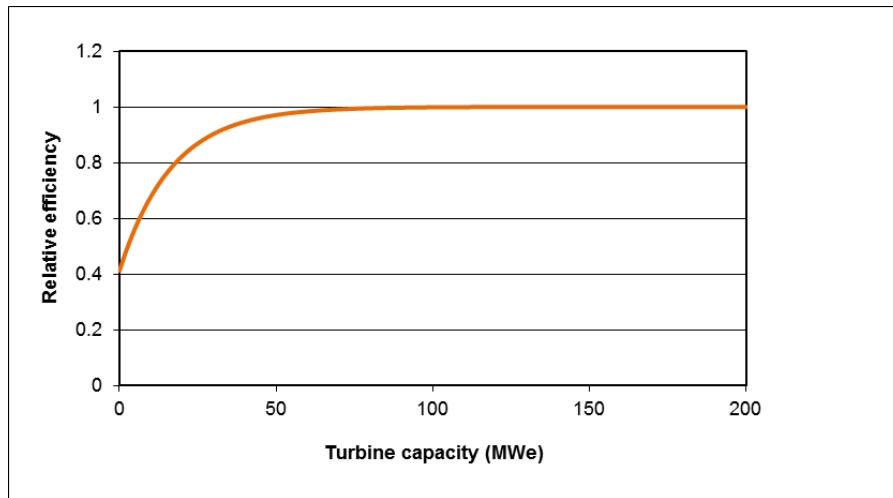


Figure 56: Relative efficiency of steam turbines against a 100 MWe baseline

O&M costs are also size dependant with only modest increases in team sizes required to maintain much larger plants leading to lower cost per kWh generated

Estimates of turbine relative efficiency versus size were used to produce the curve fit in Figure 56. Relative efficiency is used such that any steam temperature or pressure effects can be considered separately.

The change in Power Block efficiency effectively changes the contribution of all the other contributors in inverse proportion to efficiency. Thus reducing system efficiency means that the solar field must be increased in size per unit of electrical output overall.

The overall result, graphed in Figure 57, shows close to, but slightly less size dependence than the predictions of others¹⁷.

¹⁷ See for example (Morse, 2009).

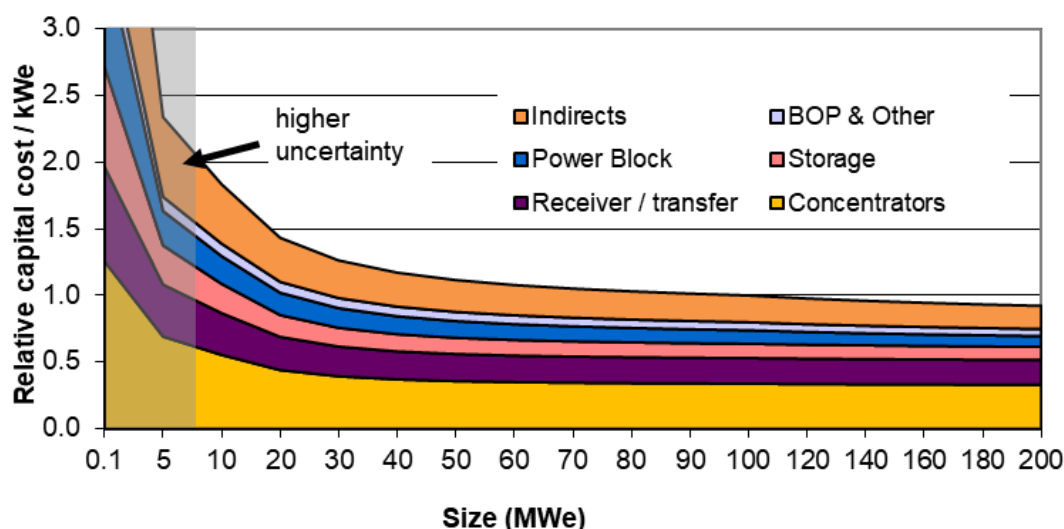


Figure 57. CSP capital cost dependency on size, relative to a 100MW_e system with 10 hours of storage.

It is seen that the result is non-linear, with a major escalation in installed cost at small system sizes and a slow but continuing decline in costs above 50MW. It can be seen that whilst moving to large (>100MW_e) systems brings cost reduction, the penalty for working in the region of 20MW_e is around 35%.

In comparison, Morse (2009) offers the Abengoa perspective on size effects in Figure 58. There is of course a very strong correlation between relative cost scaling between LCOE and capital cost, with LCOE possibly showing an amplified effect if O&M/kWh is shown to be size dependant. This is consistent with AT Kearney (2010), which reports that the companies surveyed estimated a 15% reduction in the cost per MW installed if the size of the plant were 100 MW instead of 50 MW.

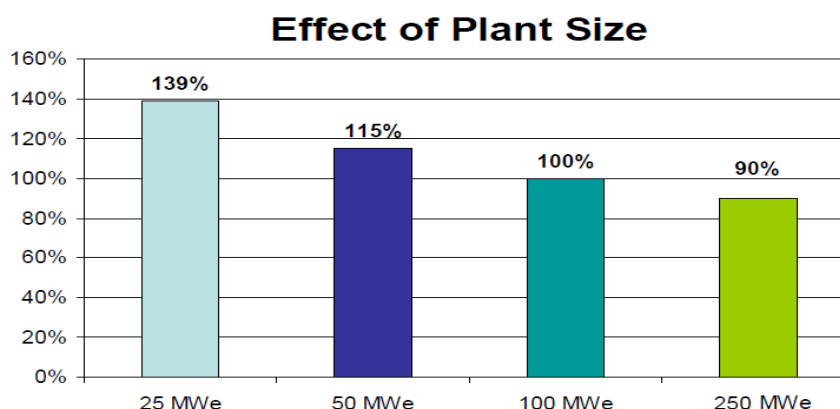


Figure 58. Effect of plant size on LCOE (assumed) against a 100MW_e base case (from (Morse, 2009)).

Whilst a cost per unit capacity penalty of more than 35% is significant, the reductions in project risk and level of grant or other support needed for early projects may justify the choice of a small system as a first step.

7.2.4. Regional effects

As well as the obvious variation of generation levels with DNI resources, it is expected that variation in capital cost will occur between regions in Australia. This arises because of variations in:

- cost of labour,
- transport costs,
- other costs of construction (eg plant hire costs, labour camp costs),
- ease of grid connection,
- availability of water.

The 2012 study referred to Rawlinsons for regional construction indices as shown in Table 21.

The variation is significant and some of the highest values correspond to high solar resource locations. Overall there is a general trend to high cost of construction in locations further from major population centres. It could possibly be argued that there is some correlation also to high costs in locations with high demand for labour during the mining boom. Taken at face value, the indices are sufficiently high in some of the high solar sites that, if they were to be interpreted as direct multipliers on the installed capital cost of a CSP system, they would outweigh the benefit of the extra solar resource.

However, there are good arguments to suggest that this would be an extreme view. An NREL analysis of trough system costs (Kutscher et al., 2010) identifies the site labour cost component in each part and suggests that it is less than 20% of the overall total. Nevertheless, it is logical that labour costs will generally increase (due to higher rates, allowances and transport) and labour productivity will decline (due to travel time, fly-in fly out regimes etc) in the more remote locations.

Table 21: Regional construction cost indices from (Rawlinsons, 2010).

CITY	STATE	Regional Construction Price Index (Rawlinsons 2010)	Variation reduced to 1/3
Capital city	Any	100	100.0
Broken Hill	NSW	125	108.3
Bourke	NSW	127.5	109.2
Inverell	NSW	115	105.0
Mount Isa	QLD	145	115.0
Longreach	QLD	135	111.7
Charleville	QLD	120	106.7
Toowoomba	QLD	103	101.0
Pt Augusta	SA	110	103.3
Roxby Downs	SA	125	108.3
Alice Springs	NT	110	103.3
Tennant Creek	NT	150	116.7
Newman	WA	165	121.7
Carnarvon	WA	145	115.0
Kalgoorlie	WA	135	111.7

A final column has been added to Table 21 to quantify a construction index, reduced to 1/3 of the overall variation from the capital city value.

7.3. Examination of LCOE sensitivity

The baseline for this analysis is the SAM default molten salt tower system, 100MW_e net with ten hours of storage as previously detailed in Table 12. Using the cost formula presented in Table 20, the total installed cost predicted is \$615M.

The baseline location, as per the 2012 study, is Longreach in Queensland, being a representative best location on the NEM with readily available solar data. As noted above in section 6.2.2, predicted annual generation at this site is 516GWh/a.

Using a de-risked WACC of 6.5%/a, O&M at 2%/a of installed cost and 25 years project life gives an LCOE of \$122/MWh.

This LCOE baseline represents the current global CSP industry favoured technology configuration constructed at a representative most favourable realistic Australian site.

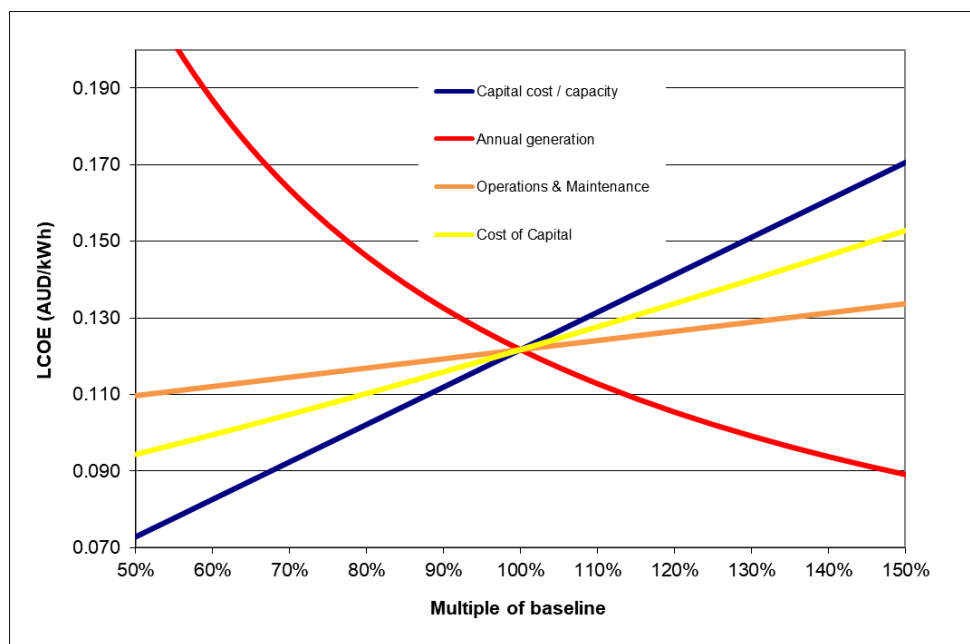


Figure 59. Variation of cost against an LCOE baseline of a 100MW_e, 10 hour storage molten salt tower system in Longreach.

From this baseline position, the effect of relative variations in key parameter values are illustrated in Figure 59. As each parameter is independently varied from 100% of its baseline value, the corresponding curve indicates the manner in which LCOE increases or decreases as other parameters are held constant.

It can be recalled from section 6.2.2, that different likely locations produced variations in generation of +/- 15%, which would lead to LCOE varying between \$110 and \$140/MWh.

It can also be recalled that different CSP technologies had different variations in relative generation from North to South and their LCOEs would move in proportion to those.

7.3.1. Effect of system size

The size dependence of LCOE follows the size dependence of installed cost very closely, as shown in Figure 60.

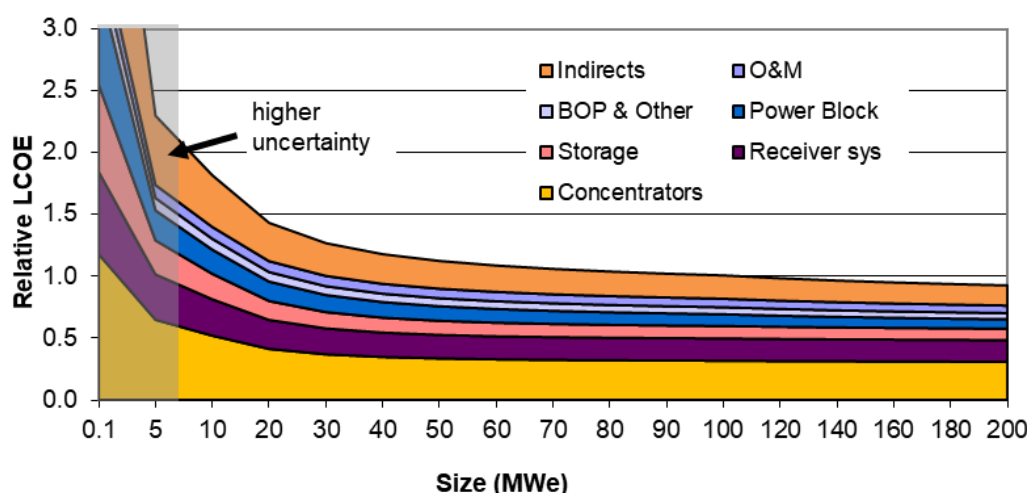


Figure 60. Estimated LCOE dependence on plant size for a molten salt tower plant with system with 10 hours storage normalised to a 100MW system.

The model that was adopted for this analysis, projects LCOE continuing to drop for larger systems. There is a general consensus however that 250MW_e represents a point of minimum LCOE. Beyond that size, LCOE begins to increase again, because the thermal losses from a large HTF network (or the optical losses from a larger heliostat field), result in decreasing system output.

7.3.2. Effect of storage

For a given plant generating capacity and nominated level of energy storage, the size of the solar field can be varied to find the minimum LCOE. If this is done for a range of levels of energy storage, the combined effect of storage level on LCOE can be examined. Carrying out this analysis for a 100MW_e salt tower in Long reach produces the results shown Figure 61. The LCOE numbers have been normalised to 1 for the case of 10 hours storage. By presenting the results as relative LCOE in this way, they become largely independent of site, technology and financial parameters assumed.

The effect of storage is twofold. It increases the overall annual generation by reducing the energy dumping that would occur from a field with a solar multiple greater than one. It also gives the ability to capture transient events too short to start up a power block. This extra generation has

the effect of lowering the LCOE contribution from all categories, even though their actual capital cost has not changed. That is, the same cost is shared across greater generation. Offsetting this, an LCOE contribution appears and grows in proportion to the number of hours of storage.

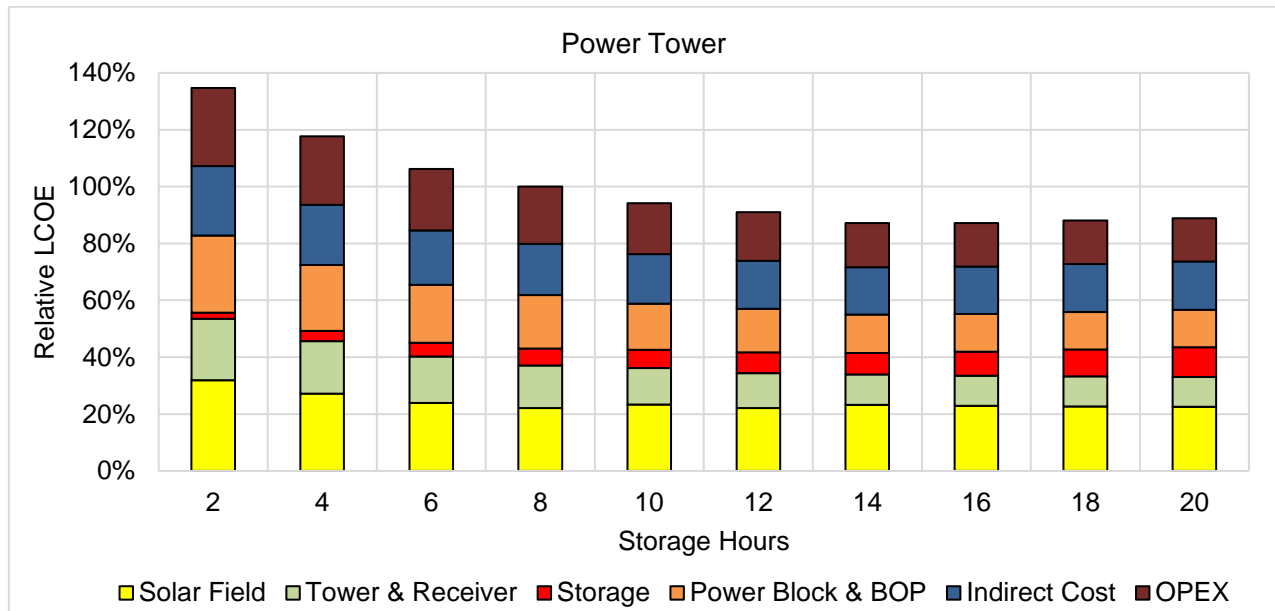


Figure 61: Impact of storage on LCOE for a 100MW_e molten salt tower plant with various levels of storage (solar field size optimised in each case)

In addition, adding storage and boosting the field size, increases the capacity factor and means that the investment in power block and balance of plant is amortised over much higher levels of generation.

As more storage is added beyond the optimum, the annual generation stops growing and begins to decline slightly due to increased standing losses and the LCOE increases with the capital cost increase. It is storage levels of around 6 to 8 hours that are best able to target evening peak wholesale prices.

7.3.3. Effect of power block size

For larger power blocks, LCOE increases in proportion to size in a slightly non-linear way, due to the effect of size on efficiency. This is largely due to the direct increase in capital cost of the larger power block which is not compensated by extra annual generation. These impacts are illustrated in Figure 62.

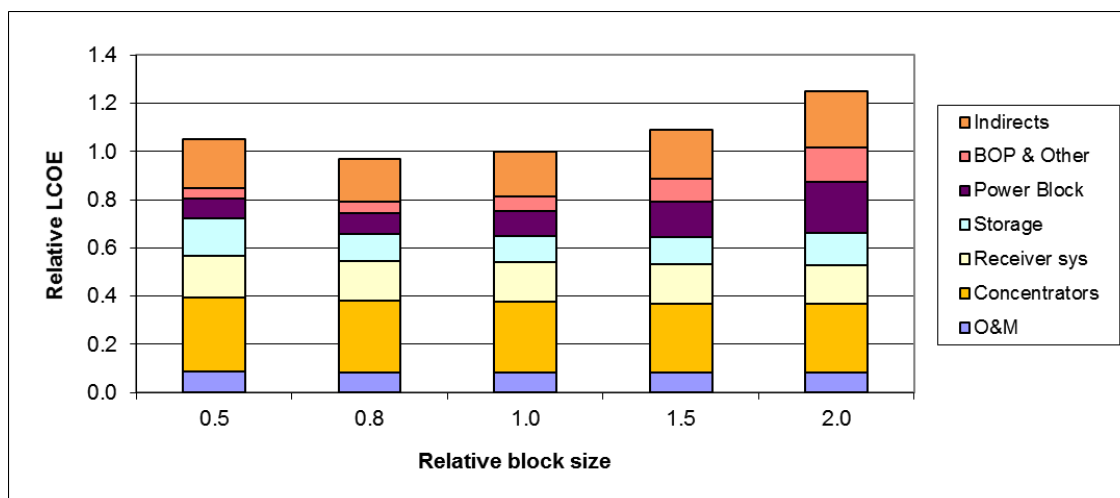


Figure 62: Impact on LCOE of power block size modelled for a molten salt tower modelled with a 2,774 MWh_{th} store and 500MW_{th} fixed collector area modelled for Longreach. The block size 1 data point corresponds to 100MW_e power block capacity.

The smallest power block shows a higher LCOE as storage levels are occasionally overloaded leading to heliostat off-steer. A large block also increases LCOE because of its larger contribution to cost, but it offers the potential benefit of being able to target energy dispatch at times of higher value and so may offer more favourable economic performance.

The larger relative power block size combinations may be considered for a system designed to preferentially dispatch at times of higher market prices of energy.

7.4. Comparison with other dispatchable renewable generation technologies

ITP has recently led a review of dispatchable renewable electricity options (Lovegrove et al., 2018). This included CSP in a back to back comparison with other technologies, specifically:

- Utility-scale wind or solar PV generation or a grid sourced mix of renewable electricity in combination with:
 - Large network connected batteries, with Lithium ion batteries considered as the representative
 - Pumped hydro storage,
 - Hydrogen storage (electrolysers plus underground storage followed by thermal generation),
- Behind the meter solar PV generation and batteries.
- Concentrating solar power (CSP) with molten salt thermal storage.
- Bioenergy:
 - Anaerobic digestion combined with gas engine power generation
 - Combustion boilers burning woody biomass with steam turbines
- Geothermal generation:
 - Hot Sedimentary aquifers
 - Engineered geothermal systems

In each case a cost model applicable for Australia in 2017 was established that considered cost contributions from the subsystems of collection, initial conversion, storage and final conversion.

When collection levels are adjusted to minimise the LCOE for any given level of storage the results are as shown in the cost graphs below. It can be seen that there are multiple options that are able to deliver a mix of firm and fully flexible electricity between 1.5 to 2 times the cost of variable generation from wind or PV at every timescale, with some options below, and multiple options that fall within a general least cost band. Given the uncertainties and range of variation, and the fact that calculations are based on 2017 costs, it would be certainly be incorrect to identify one particular technology as 'best' for a given timescale.

As shown in Figure 63, beyond 6 hours storage, concentrating solar thermal and Pumped Hydro systems linked to wind and solar are both among the most competitive options studied.

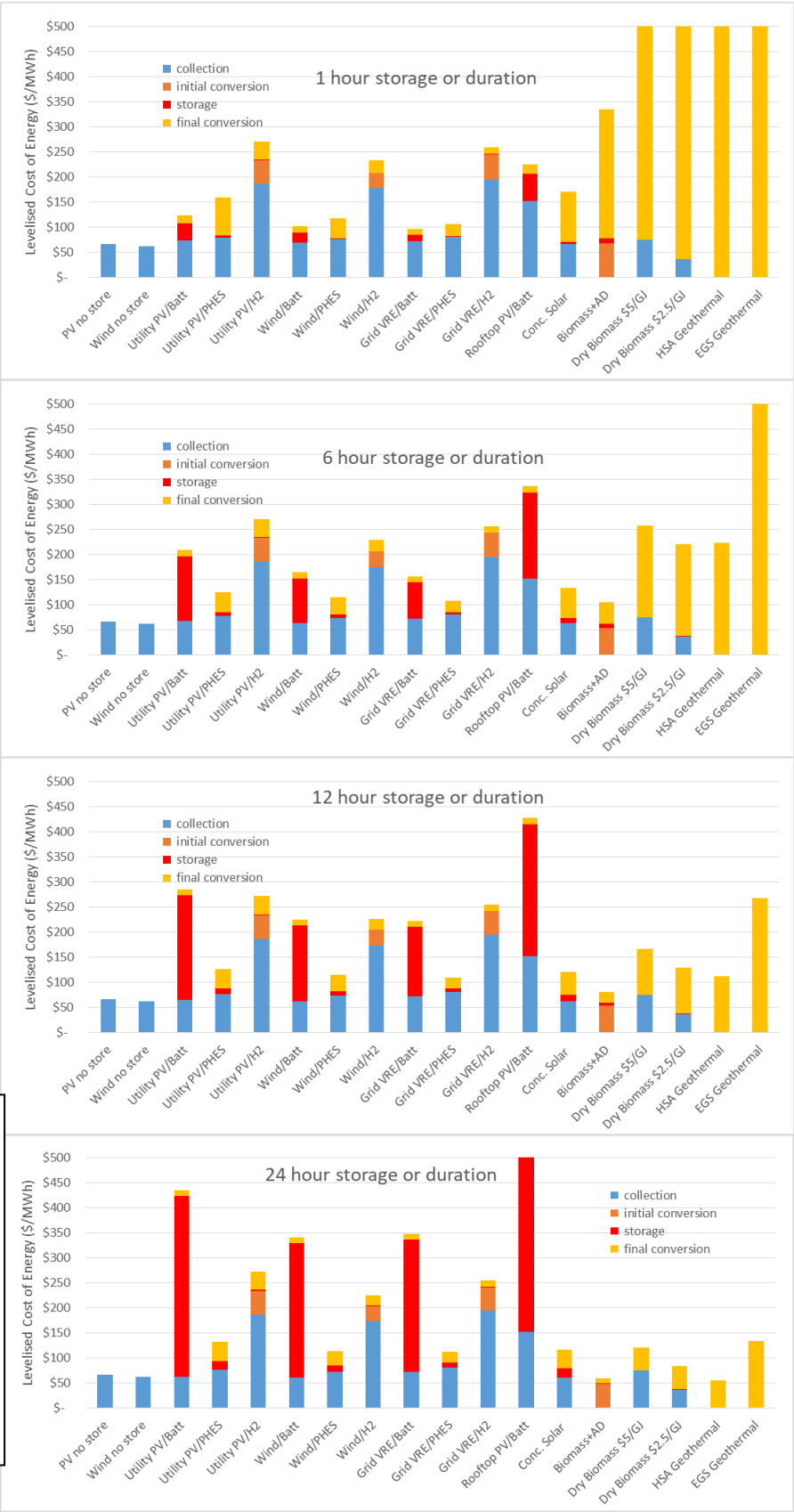


Figure 63:
LCOE by
component and
technology for
different
durations of firm
daily generation
or storage
hours, 100MW
systems, 2017

8. FUTURE TRENDS

There have been some major recent studies that examine future trends in CSP.

The International Renewable Energy Agency (IRENA) published in 2017 the “Renewable Power Generation Costs” an extensive analysis regarding actual cost trends for the main renewable power technologies including CSP. The assessment is based on the latest cost and auction price data from projects around the world.

The Spanish Renewable Energy Association (APPA) released in 2017 its already traditional “Study of the Macroeconomic Impact of Renewable Energies in Spain”. The document undertakes an exhaustive review of the current situation of clean energies including CSP. The document analyses the energy mix, current level of penetration, job creation, generated savings, the electrical grid, etc.

Greenpeace International, SolarPACES and ESTELA released in 2016 “The Solar Thermal Electricity Global Outlook”. The report undertakes a thorough study for the future growth scenarios of CSP at international level in terms of capacity growth, electricity generation potential, job generation and carbon savings.

8.1. Growth Trends

8.1.1. Past forecasts

There are a variety of past forecasts for the global growth of installed CSP generation. The ‘CSP Global Outlook’ study produced jointly by GreenPeace, SolarPACES and ESTELA (Richter et al., 2009) indicates that with appropriate efforts, *‘concentrated solar power could meet up to 7% of the world’s power needs by 2030 and fully one quarter by 2050’*.

In the “SunShot Study” (USDOE 2012), predictions for the US market alone are 28GW_e by 2030 and 83GW_e by 2050 if the ambitious cost reduction trajectory targeted is achieved.

The International Energy Agency (IEA) published roadmaps for both CSP (STE) and PV in 2010. In September 2014, they released updated versions of these. The 2014 IEA CSP roadmap is a comprehensive review of progress in the industry. It finds that CSP deployment has grown slower than predicted in 2010. However, it remains confident of a strong future and continued growth, with the previously foreshadowed deployment goals simply delayed by several years.

The confidence stems from CSP’s strongly established cost advantage in proven energy storage. The delay in deployment is seen as a delay in establishing the increased sophistication in renewable energy policy measures that is needed around the world. Whilst there is growing recognition of the essential role of energy storage, most renewable electricity development policy

measures still focus on rewarding generated renewable energy irrespective of the time of generation, whilst ignoring supply and demand and the impact on networks etc. In such circumstances the lower LCOE of PV and wind will cause those variable renewable technologies to dominate the market.

8.1.2. Current forecasts

To date, around 100 CSP projects have been completed (combining around 5.1 GW of installed capacity, (as discussed in Chapter 3) and approximately 80 additional projects are currently under construction or under development. Figure 64 shows the expected global installed capacity that could result from these in year 2024 as a red circle. This estimation is obtained based on the ITP estimated likelihood that each of these projects will be completed within the next six years. On average a 30% probability was applied, with a much reduced value for projects that were known to be unlikely and a much higher value if construction was close to or already commenced. If the net (nameplate) capacity of each project is multiplied with these probabilities an installed capacity of around 8.5 GW_e is predicted. It should be noted, however, that new projects are likely to be announced and some of these could be completed before 2024 and hence the actual installed capacity in 2024 could be higher.

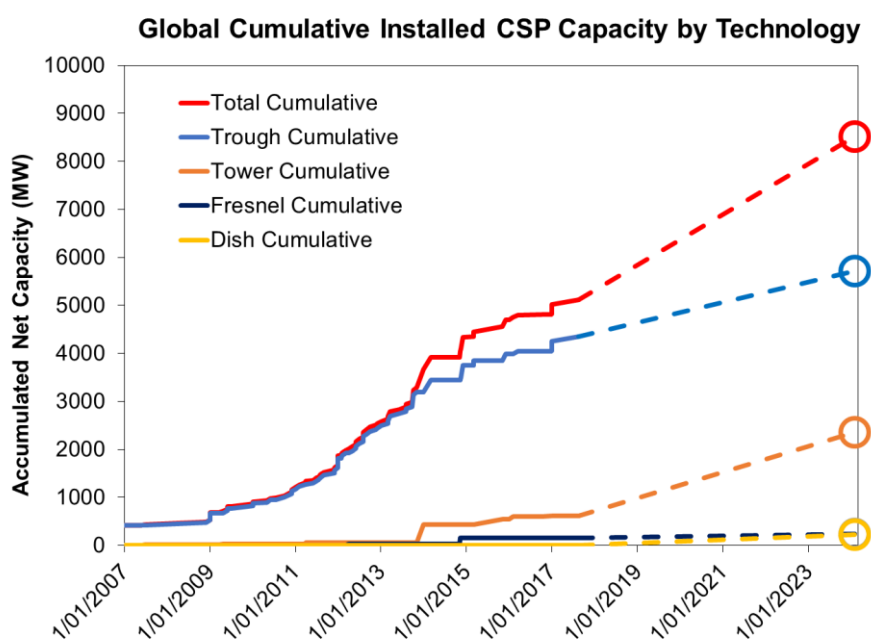


Figure 64: Global growth in CSP installed capacity by technology since 2007 and future extrapolation (ITP).

The breakdown by technology in Figure 64 shows that 85% of the currently installed capacity uses parabolic trough technology, with power tower currently at 12%, linear Fresnel at 3% and dish technology currently without any commercial plants in operation. The largest growth is

expected in power tower technology from 600 MW_e today to 2.4 GW_e by 2024, while parabolic trough technology is predicted to growth by 1.4 GW_e by 2024, linear Fresnel by 77 MW_e.

For Oceania (effectively Australia), the most recent '*CSP Global Outlook*' by ESTELA in 2016 predicts that an installed capacity of 4 GW could be reached by 2030 under a moderate growth scenario.

Typically, new technologies follow an evolution of deployment that begins with gradual acceleration, has a period of exponential type growth and then slows and levels off at a saturation level. The early stage of this process can be modelled by identifying a compound annual growth rate (CAGR).

After a strong start in the late 1980's CSP had a hiatus of 15 years, this was followed by several years of very strong growth from 2005 till 2014, since then growth has moderated. The first CSP plants were enabled by policy measures in the US motivated in response to the 1970s oil crisis. Global interest in renewable energy re-emerged in the 1990's in Germany and Denmark as climate change and other environmental issues were given priority. Those countries were naturally first drawn to wind rather than solar. However this rising interest in Europe lead to Spain taking the initiative in CSP from 2005 onward.

The key characteristic of dispatchability is driving demand for CSP generation. Indeed, the greater the level of uptake of intermittent clean energy, the more the demand is likely to be for dispatchable generation, such as CSP. In addition, there is a significant positive feedback effect on growing capacity and cost reductions with new technologies (the progress ratio). Installing capacity assists with progress in cost reductions, while industry momentum is assisted with further cost reductions.

Different compound growth curves can be fitted to the progress of CSP in the past. If the entire effort from the first SEGS plant at the beginning of 1985 to the completed 5.1 GW at the end of 2017, is fitted, the result is a historic CAGR over nearly three and a half decades of about 19.6% pa. However, there was a long period of zero activity between 1990 and 2006, the early phase from 1985 to 1990 averaged growth of 71% for a short while and the latest phase from 2007 to 2017 has averaged 27.5% pa growth. Figure 65 shows the global growth curve to date (red solid line) and extrapolations of the historic growth curves of 19.6% pa (1985 to 2017) and 27.5% pa (2007 to 2017) until 2030. If CSP growth will continue along these past growth trajectories, installed capacity would reach between around 50 and 100 GW by 2030. Also shown is a growth curve of 38.8% pa starting in 2018 at the installed capacity at this date. This is the growth rate that would lead to the installed capacity of 260 GW in year 2030 predicted in the 2014 *IEA CSP Roadmap*.

Installed capacity (in GW_e) is a somewhat misleading metric, since systems with storage and a higher capacity factor produce more energy and have a larger system area per GW_e of installed capacity. Arguably it would be better to analyse in TWh per year as per the IEA projections,

however installed capacity remains the most commonly quoted metric. Note that if the capacity installed is considered as capacity at an equivalent 25 to 30% capacity factor, then Australia's entire current electricity needs would map to a capacity of about 100 GW_e.

Since 2006 CSP plants with in-built thermal energy storage have been built. Existing plants have a combined storage capacity of about 14 GWh_e. Storage capacity is expected to continue to grow to at least 33 GWh_e by 2024 (based on projects currently under development or under construction). The annual electric energy generation by CSP is expected to grow accordingly, from approximately 13 TWh_e today to at least 21 TWh_e in 2024.

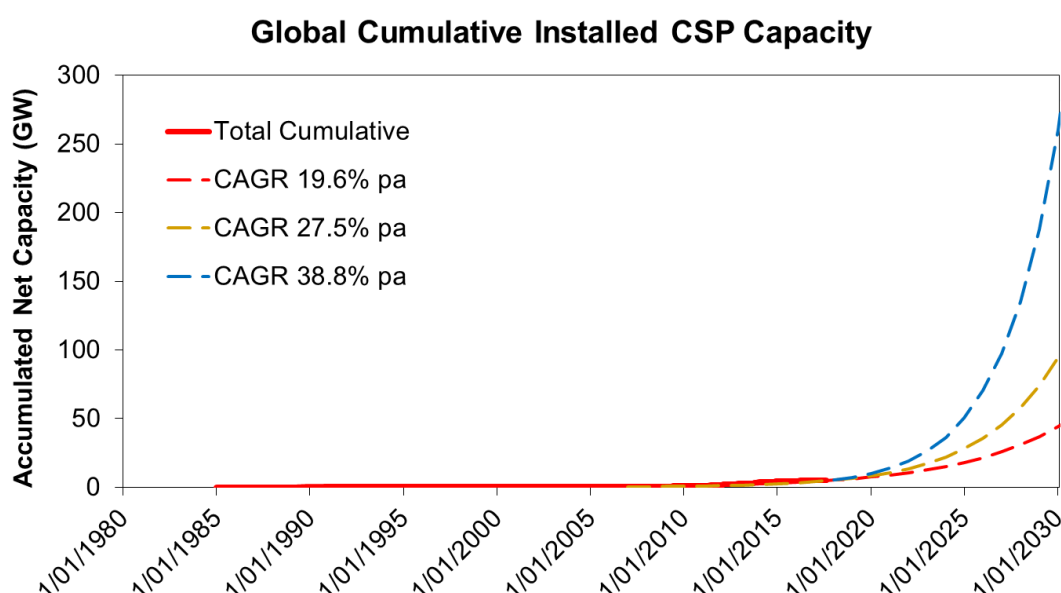


Figure 65: Potential Global CSP Generation Growth Scenarios until 2030, based on past growth rates over the periods of 1985 to 2017 (19.6% pa) and 2007 to 2017 (27.5% pa) and based on the future growth rate implied by the IEA forecast of 260 GW of installed CSP capacity by year 2030 (38.8% pa).

There is a clear pattern that in any given jurisdiction the vagaries of political cycles and economic downturns, can give rise to uneven progress.

For the next decades, there are three scenarios that can be considered:

- Complete stagnation of the global CSP industry as competing technologies win on cost.
- Piecemeal growth spurts in various countries at various times that allow the global industry to continue at least with the 19% pa average growth achieved to date.
- Strong growth of around 30% to 40% pa which is consistent with the track record of wind and PV and has been achieved by the CSP sector in particular years in the past.

Whilst complete stagnation of the CSP industry is possible, the evidence suggests that this seems unlikely given the need and demand that can be identified for dispatchable clean energy. The strong growth scenario or indeed, even higher rates of growth are clearly possible. This would arise from a concerted global effort to address GHG emissions and future energy security in a strategic manner.

The current geopolitical situation suggests something close to the middle scenario is the most likely outcome. This scenario is the one that would be the best basis for Australia to plan on.

8.1.3. Potential for growth in Australia

The AEMO report further shows a schedule for phasing out existing coal and gas power stations that reach their operating life (Figure 53) between now and year 2040. This results is expected to result in a reduction in installed capacity of around 15 GW and in generation capacity of around 70 TWh. The AEMO plan projects that around 28 GW of large-scale solar and 10.5 GW of wind capacity will replace these fossil power plants, with 17 GW of installed capacity provided by new and existing energy storage systems. A marked increase in utility-scale storage capacity approximately from 4 to 17 GW is predicted for the years 2030 to 2040. The AEMO report predicts that in none of the four states gas power plants will reach a major share in the electricity mix in 2040. CSP technology is ideally suited to meet increasing demand for storage and flexible synchronous generation with inertia.

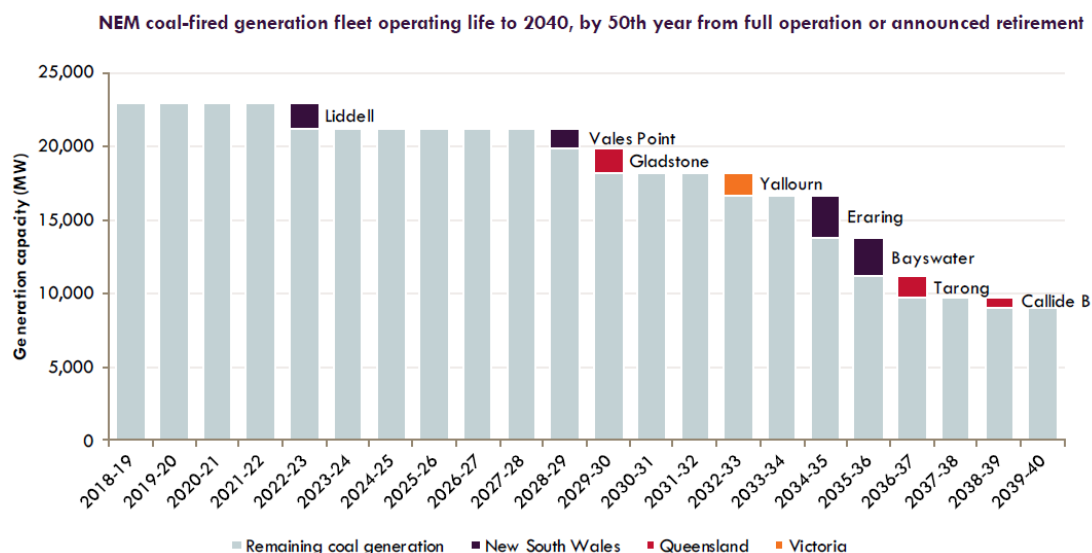


Figure 66: Expected retirement dates and development of generation capacity of Australia's coal power fleet until year 2040 (source: AEMO, 2018).

8.2. Cost Reduction Potential

8.2.1. Previous studies

ITP's 2012 study reviewed an extensive range of previous studies that consider long term growth in deployment and correlated reductions in cost of energy. All predicted strong growth and cost reduction, some have proved overly optimistic. The two most current at the time were the roadmap published by the IEA for CSP technology (IEA 2010A) and the report prepared by AT Kearney (2010), who were commissioned by ESTELA and Protermosolar (European and Spanish CSP industry associations, respectively) to produce a study of energy cost reduction projections to 2025.

They have completed a projection of cost reduction potential over the coming years based on knowledge of specific areas for improvement. A range of key areas for reducing cost of manufacture and increasing annual output are identified for each of Trough, Linear Fresnel, Dish and Tower technologies. Benefits are projected from an evolutionary increase in the average size of systems.

All of these measures together are suggested to result in an overall reduction of LCOE by 2025 relative to 2012 of 40 to 55%, as shown in Figure 67. Over the same time period, they suggest global installed capacity could reach between 60 and 100 GW depending on policy measures in place (in agreement with the growth projections based on historical growth rates, section 8.1.2).

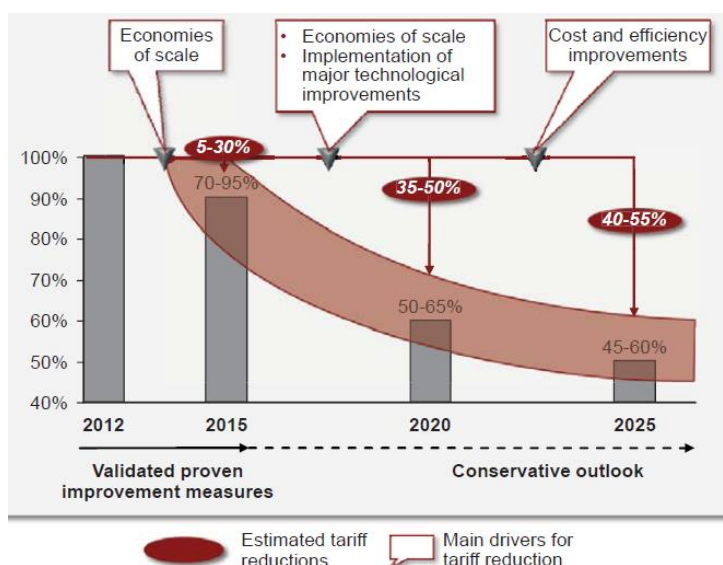


Figure 67: Estimated CSP cost / LCOE reductions (Reproduced from AT Kearney, 2010)

The IEA 2014 roadmap analysed the extent to which cost reductions have been achieved since 2010 and the forecasts of what will be achieved in the future. The overall conclusion is that cost

reductions will continue but that the factors influencing the data are very complex and prevent an accurate global learning curve to be drawn yet.

Factors that influence this include:

- A large number of standard trough plants limited to 50MW_e and with older design approaches locked in by FIT rules, have been built in Spain and this has constrained efforts to seek size related cost reductions.
- In other countries, much of the new capacity has been first of a kind for particular countries and companies, so has incurred higher costs because of that, irrespective of underlying global cost reductions.
- First of a kind projects in other countries have also tended to favour conservative low technical risk trough plants.
- Large tower projects that have come on line are also largely first of a kind with associated higher costs.

Published PPA information provides some indication of cost reductions. The IEA reports that Spanish plants benefited from FiTs of around USD 400/MWh, the PPA of the first phase of the Noor 1 plant at Ouarzazate in Morocco is USD 190/MWh for a 160MW trough plant with three hour storage and a recent plant in the United States secured a PPA at USD 135/MWh, but taking investment tax credit into account, the actual rate is about USD 190/MWh. These are encouraging trends, however different countries have different costs of construction and DNI levels and there can be various escalation and duration assumptions in PPAs making them hard to compare.

Overall, the IEA concludes that capital cost learning should still proceed on the basis of at least a 10% reduction per doubling of installed capacity. This together with projections for deployment lead to their prediction of capital cost reduction over time shown in Figure 68.

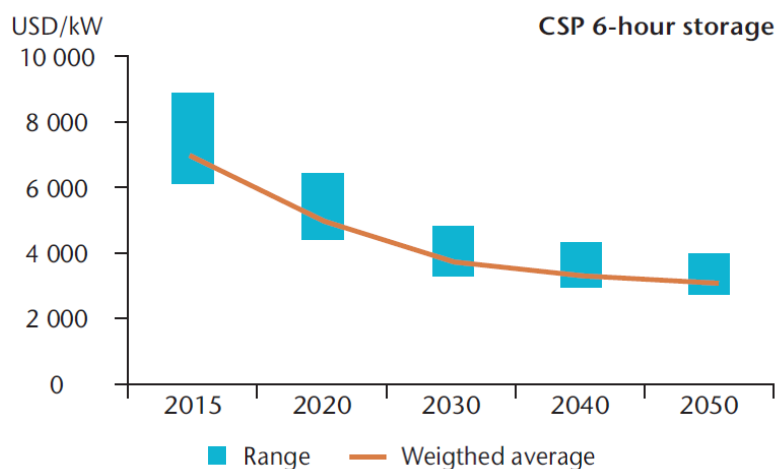


Figure 68. Revised cost reduction trajectory from the IEA 2014 CSP Roadmap.

8.2.2. Learning curve predictions

It is common practice to examine the track record of a technology using the idea of a “Progress Ratio”. This is the multiple by which the cost changes each time the total installed capacity is doubled. In other words, a progress ratio of 85% for example, would mean that cost decreases by 15% every time the installed capacity is doubled.

Expressed mathematically:

$$Cost = C_0 \times PR^{(\log_2(Q/Q_0))}$$

Where C_0 is the initial cost per unit and $(\log_2(Q/Q_0))$ is the number of doublings in capacity to achieve a capacity Q from a starting point of Q_0 .

Precedents from other fields are a reasonable indicator of value for progress ratio. GEF (2005) identified a relevant study by the IEA (2000), that analysed the progress ratios of a large variety of products from the electronics, mechanical engineering, paper, steel, aviation, and automotive sectors, showing a wide spread with a median value of approximately 0.82 apparent. ITP’s 2012 study reviewed past analysis of cost reduction predictions both for CSP and analogous energy technologies in general and concluded that CSP progress ratio’s should fall between 90% and 80%. The IEA’s 2014 Roadmap projected a progress ratio of 90% (10% cost reduction on doubling).

To put these costs and learning rates (=100%- progress ratio) into perspective with other renewable energy technologies, Figure 69 shows the learning curves for the average levelised costs for international CSP, PV and Wind (onshore and offshore) projects, from the *Renewable Power Generation Costs* report, recently published by the International Renewable Energy Agency, IRENA (2017).

The cumulative capacities of PV and onshore Wind are currently in the order several hundred GW each and hence around 100 times higher than that of CSP (5.1 GW). For the period 2010 and 2020, IRENA estimates the progress ratio of CSP to be around 70% (30% cost reduction per doubling), while those of PV and onshore and offshore wind are estimated at around 65%, 79% and 86%, respectively. If the learning curves for each technology continue into the future, Figure 69 suggests that, above around 10 GW of installed capacity, CSP will achieve lower LCOE than any of the other renewable energy technologies at equal cumulative capacity.

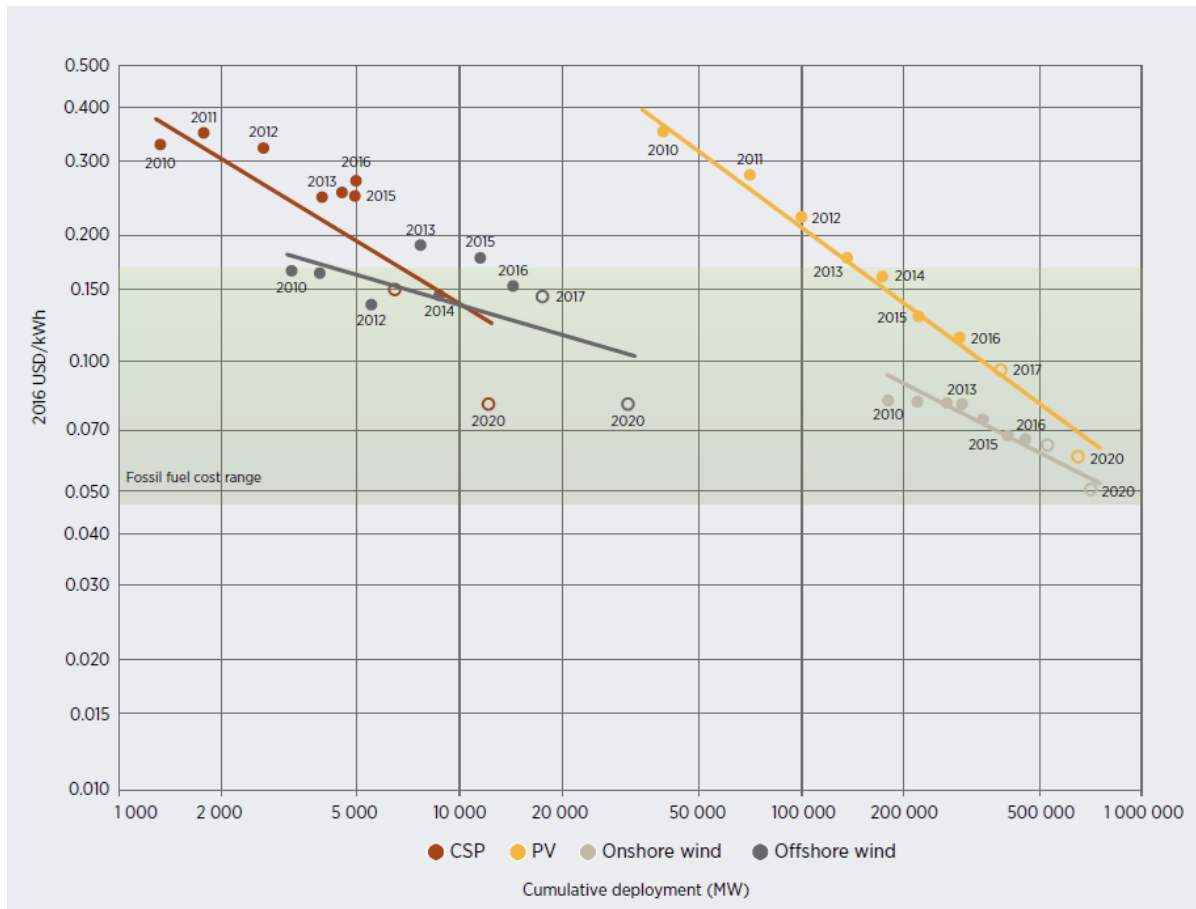


Figure 69: Average LCOE vs deployment on a Logarithmic scale for International CSP, PV and Wind Energy, IRENA, 2017

The IRENA suggestion of a 30% cost reduction on doubling for CSP seems overly optimistic and although compatible with the results to date it is not supported with high certainty. The IEA number of 10% on the other hand appears rather conservative. The most likely result would appear to be a value of around 15%.

From a policy perspective, a forecast of how these cost reductions are likely to track with time is useful. Compound growth is likely to occur at a rate that will be at least 20% per year and most likely higher.

Figure 70 plots the progression over time of relative cost of energy¹⁸ under a range of possible compound annual growth rates for a 15% reduction on doubling with an end 2017 starting point.

¹⁸ Note that LCOE is strongly dependant on capital cost, but also depends on O&M costs and financing costs. To a first approximation LCOE and capital cost are assumed to reduce over time according to the same progress ratio.

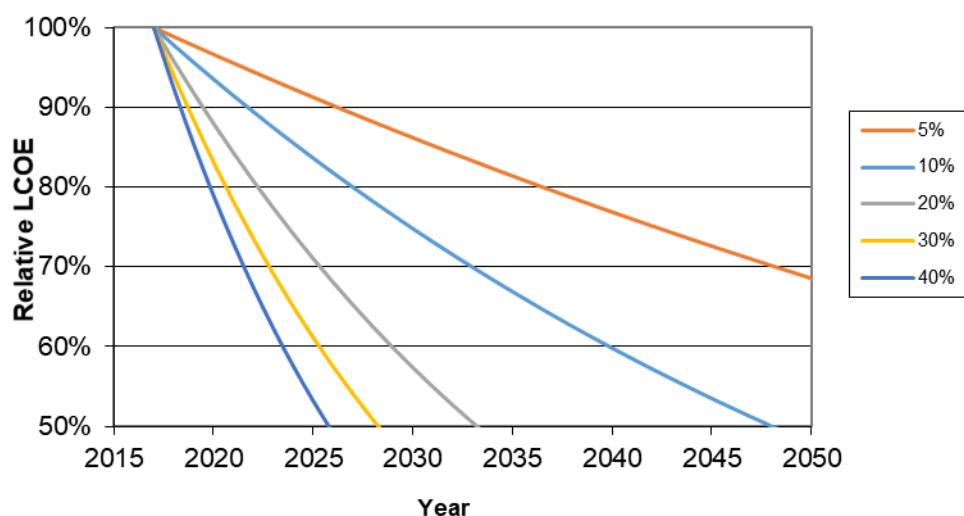


Figure 70: Impact on LCOE of different compound annual growth rates for a 15% cost reduction on doubling.

On this basis, a cost reduction of around 40 -50% by 2030 might reasonably be expected. No attempt has been made here to attribute differing progress ratios to different subsystem components or to O&M. To the accuracy of this analysis, the time and deployment evolution of relative LCOE will be the same as relative capital cost.

From this analysis, the follow on question is - at what point does cost and value converge in the Australian market place? Figure 71 shows the predictions of possible cost of energy and revenue versus time from the 2012 study, with the new baseline CSP cost of energy data points superimposed. It is seen that the cost reduction implied is close to the maximum level predicted in 2012. If potential revenue were to be assumed constant from this point, cost and income might arguably have converged at the present time. However, this would be for mature nth of a kind plants with no risk premium on finance, a situation that does not yet apply. It would also assume the current average wholesale prices for electricity and value of RECs or equivalent, could be relied on into the future, both issues subject to great uncertainty.

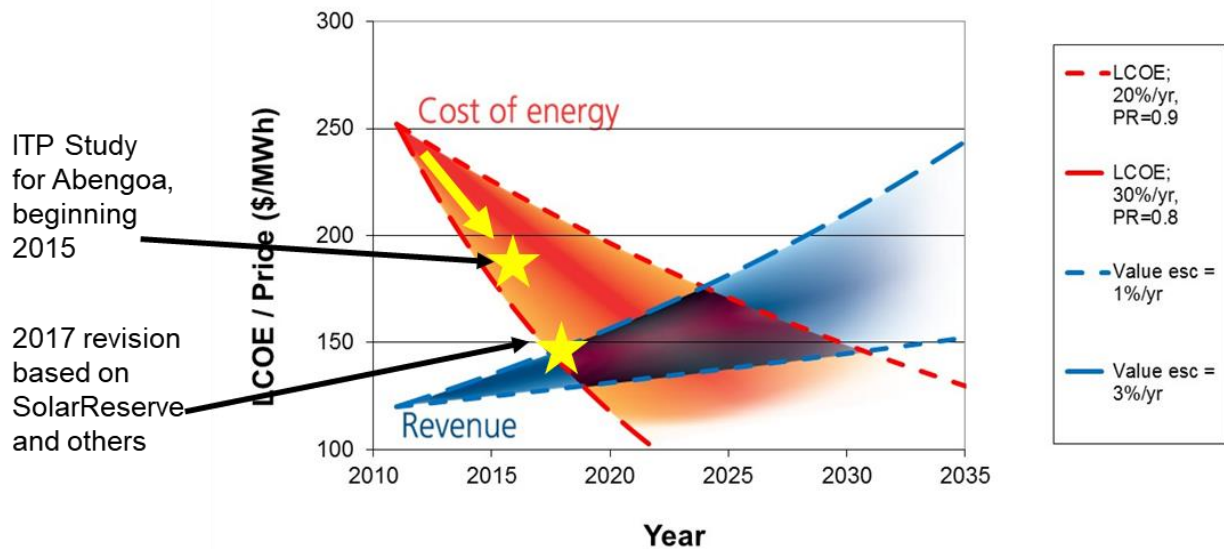


Figure 71: Revised baseline LCOE compared to previous analysis (ITP 2012) of LCOE over time together with revenue.

8.2.3. Drivers for cost reduction

CSP is considered to be an essentially proven technology that is at an early stage of its cost reduction curve. A period of growth in installed capacity, together with decline in cost of energy produced is confidently predicted by the industry.

The trend to a learning curve of capital cost reduction as installed capacity increases is logically linked to:

- technical improvements, building on knowledge (both local and global) gained from installed plants and parallel R&D efforts to identify and realise cost reductions (eg wireless controls) and performance improvements (eg increase in efficiency, storage temperature, product durability, etc;),
- learning improvements from deployment and operation, such as reduced construction periods, lower O&M costs, product standardisation, etc,
- scaling to larger installed plant size, that allows for more efficient and more cost effective large turbines and other components to be used, and for fixed construction/management costs and overhead to be spread over a larger project,
- volume production that allows fixed costs of investments in production efficiency to be spread over larger production runs, and
- EPC margins decreasing as risk is reduced and competition is strengthened.

These sources of cost reduction are interlinked. Technical improvements for example require learnings from deployment in order to be effectively leveraged. Manufacturing efficiencies, which are both at the small component level and in the actual on-site installation, require an on going pipeline of projects to be developed effectively. Whilst, to a considerable extent, learnings can follow from global experience, each country that seeks to incorporate CSP solutions will benefit most if it has a consistent pipeline of local projects established. This is particularly important to establish a mature and efficient supply chain for those aspects that must be local rather than imported. This includes the most obvious area of building skills and experience in a workforce to do the actual installations.

The solar field costs typically represent 30-35% of the total plant costs and are one of the main cost drivers. Significant cost reductions have already been realised in recent years and further cost reductions of up to 25% are expected over the coming years. Furthermore the improvement of the optical and mechanical designs of solar concentrators (eg heliostats) will enhance collector reflectivity as well as the targeting accuracy resulting in a reduction of the reflecting mirror areas.

The second main driver that will support the cost cutting trend will be with the thermal storage. The technological breakthroughs will allow the HTF to perform under higher temperatures increasing the storage capacities. At the same time the lowering of the melting points will help as well enhance the system efficiency, as this will help minimising the parasitic losses derived from electric heaters and electrical tracing needs for piping which at the same time represents a cost reduction. Additionally standardisation and storage material developments will contribute further to cost reductions.

The LCOE of the plants will also be reduced through improved system efficiency via three main factors:

- Higher operational system temperatures involving higher thermodynamic cycle efficiencies.
- Development of improved turbine designs adjusted to the operational conditions of a CSP plant contributing to improving the cycle efficiency.
- Improved control strategies and development of automated tracker and calibration systems.

In addition to the direct capital cost effects, the financial terms applied to capital improve as the technology becomes better known and proven. Operations and maintenance costs also benefit in similar ways. The development of optimised O&M strategies and procedures contribute to reduce the yearly maintenance costs.

The substantial reduction in the baseline predicted CSP cost of energy for recent tower plants is an example of a real identifiable improvement based on a technology change. It is directly attributable to the choice of the tower plus molten salt configuration by different companies. This choice is consistent with a broad consensus within the CSP industry. Salt towers apparently

deliver this major LCOE improvement in large part because they directly heat molten salt and are able to increase its temperature further and store nearly three times as much energy compared to trough plants for the same investment. This switch from troughs without storage to towers with storage can be considered as real, because sufficient tower plants have now been built to allow cost and performance analysis to be treated with greater certainty.

8.2.4. Improving Efficiency

Research efforts to reduce the cost of energy include a focus on reducing deployment costs and improving system efficiency. Efficiency in turn is a product of the subsystem efficiencies:

- Optical efficiency - how reflective are the mirrors, eg heliostats, and how accurate are they at directing the light into the receiver.
- Receiver efficiency - how much of the energy intercepted is absorbed rather than lost from re-radiation and other heat losses.
- Heat transport efficiency - reduced by heat losses from conduction through insulation and parasitic energy for pumping requirements.
- Storage efficiency - reduced by heat losses from conduction through insulation and other mechanisms.
- Power cycle conversion efficiency - losses from taking heat and converting it to electricity or other useful products.

Optical efficiency is addressed in conjunction with improved heliostat or collector designs. Significant international efforts have already gone into this area. In Australia, Raygen (ARENA, 2015, 2013a), Vast Solar (ARENA, 2013b, 2012b), CSIRO (ARENA, 2009) and ASTRI (ARENA, 2013c) are all making original contributions to heliostat design.

Receiver efficiency is increasingly critical, as higher temperature receiver designs are developed for tower systems. It is a key topic for both Australian and International R&D. The ANU bladed receiver project is an example of a novel idea for re-working the geometry of a tower receiver (ARENA, 2014c) with blade shaped elements that suppress convective heat loss. It is a joint project with the US Sandia laboratories, a partnership that followed the ASI initiatives at encouraging Australia and US solar research collaboration. It aims to identify optimised arrangements that should improve receiver efficiency with minimal increase in capital cost and is already the subject of a patent.

Storage and transport efficiencies are already high, although there is still room for improvement. For those sub-systems, the effort is more directed at cost reduction and development of approaches compatible with higher operating temperatures and without the challenges of solar salt's high freezing point. Vast Solar's approach of using sodium as the heat transfer fluid has the potential to provide benefits in this area (ARENA, 2013b, 2012b).

The biggest limiting factor on overall solar to electric conversion efficiency is the power cycle used. So far, commercial CSP systems have all used steam turbine power blocks. These are a mature technology with little scope for further efficiency improvement. However, their efficiency is increased by higher steam temperatures and pressures. This is one of the reasons why tower systems are increasingly favoured over trough systems.

8.3. Technology R&D areas

R&D efforts are designed to achieve two ends – support the near term efforts required by industry to roll out improved versions of existing technology (evolutionary R&D), and accelerate the efforts to bring forward the next generation of CSP technology that will supersede existing technology (step change R&D). R&D cannot be expected to solve the cost problem in isolation.

CSP R&D is not identifiable as a discipline. It is rather an “interdisciplinary” and “systems engineering activity”. Individuals from different backgrounds using wide ranging facilities can contribute to overall goals. Globally, the CSP community is well coordinated and has reached strong consensus views on the R&D priorities leading to industry growth. This coordination is largely facilitated by the IEA Solar Power and Chemical Energy Systems (SolarPACES) program. This program has all the currently active countries as members: Australia has been a member for nearly 20 years. A major focal point of the SolarPACES community is the annual conference that is well recognised by both research institutions and the major commercial players.

For CSP (or any new energy technology), technical R&D aims to help improve the economic performance by addressing:

- Construction cost reduction
- Improvements in the efficiency of energy conversion
- Reductions in O&M costs
- Broadening the market value and range of application.

For this study, to assist priority setting, the suggestions from the sources reviewed plus direct experience and input from R&D players has been used to summarise the most relevant topics using outcome-based descriptions rather than specific technology solution-based descriptions (Table 22).

Table 22: Summary of Technical R&D Priorities for all CSP types. The nature of the topic is categorised as evolutionary or step change in its outcome.

Topic	Concentrator type	Goal	Timescale	Nature	Potential for cost reduction
Solar Concentrators					
Optimisation of support structure design and size	All	Constr. cost reduct.	Short to med.	Evolut.	Med.
Improvement of structure manufacturing processes	All	Constr. cost reduct.	Short to medium	Evolut.	Large
Improvement of solar field installation processes	All	Constr. cost reduct.	Short to medium	Evolut.	Large
Optimisation of tracking system / drives	All	Constr. cost reduct. / Reduce O&M	Short to medium	Evolut.	Small
Advanced mirror panels and materials	All	Constr. cost reduct. / Reduce O&M	Medium	Step ch.	Med.
Optical efficiency improvement	All	Efficiency improve.	Short to medium	Evolut.	Small
Improved mirror cleaning systems	All	Efficiency improve / Reduce O&M	Short	Evolut. / Step ch.	High
Receiver systems (including HTF systems)					
Improvement of evacuated tube receivers	Trough / Fresnel	Efficiency improve.	Short	Evolut.	Small
Alternative HTF's for below 500°C	Trough, Fresnel	Efficiency improve.	Short / medium	Evolut. / Step ch.	Med.
Alternative HTF's for above 500°C	Dish, Tower	Efficiency improve.	Med/ large	Step ch.	Large
Reduce HTF line losses and parasitics	Trough, Fresnel, Dish	Efficiency improve.	Short	Evolut.	Med.
Improve receiver assembly processes	All	Constr. cost reduct.	Short	Evolut.	Med.
Thermal Energy storage systems (CSP)					
Solar Fuels production	Dish, Tower	New market	long	Step ch.	Large
Other thermal storage below 600°C	All	Constr. cost reduct.	Med	Evolut. / Step ch.	Large
Thermal storage above 600°C	Dish, Tower	Efficiency improve	Med / lg	Step ch.	Large

Thermochemical storage	Dish, Tower	Efficiency improve	long	Step ch.	Large
Molten salt system improvements	All CSP	Constr. cost reduct.	Short	Evolut.	Large
Electrical generation systems					
Improved /Advanced steam turbines	All	Efficienc. improve	Med.	Evolut.	Med.
Advanced thermal power cycles	All	Efficienc. improve	Med / lg	Step ch.	Large
Systems optimised for 1-10MW _e	All	New market	Sh/Med.	Step ch.	Med.
Improved Stirling engines	Dish	Efficienc. improve, reduce O&M	Sh/Med.	Evolut.	Small
Low / zero water use cooling	All	Efficienc. improve, reduce O&M	Sh/Med.	Step ch.	Med.

The assessment of cost reduction potential is against overall system cost / LCOE not the subsystem alone in the final column is not to be read directly as a priority for action. Priority setting must be specific to country and organisation and will also be informed by other parameters such as:

- Investment and time needed to achieve significant progress
- Position of organisations in the development chain
- Particular needs / competitive advantages of organisations / countries

Australia has some specific drivers that shape R&D priorities, in addition to the shared global issues:

- A strong economic dependence on fossil fuel exports
- A unique end-of-grid market segment
- A unique off-grid market segment
- A smaller economy and smaller realistic R&D budget than the main global players
- An inventive, CSP R&D capability that is close to the forefront of international activity
- A strong concern around water supply and management issues.
- An identified need for dispatchable renewable electricity generation.

The overall trend of CSP plants to operate at higher temperatures to improve the thermal efficiency of power generation, requires new or improved heat transfer and storage media and hence new receiver designs.

A recent review article discusses the commercial state-of-the-art and advances in central receivers (Ho, 2017). Potential high-temperature heat transfer media include inert particles, pressurized inert gas (e.g. CO₂, helium), halide (chloride and fluoride) and carbonate molten salts

and liquid metals (sodium, lead bismuth). Much of the current R&D on high-temperature receivers is targeted for operation with the supercritical-CO₂ Brayton power cycle operating at $\geq 700^{\circ}\text{C}$ (section 2.2.2).

Each technology pathway involves its technical challenges and risks, as discussed in the recent CSP Gen3 Demonstration Roadmap (Mehos et al., 2017). Table 23 provides a summary of current technical challenges and risks identified for next generation molten salt, particle and pressurized gas based CSP systems for towers.

Table 23. Technical challenges and risks for towerCSP systems based on the three pathways considered in the US DOE SunShot CSP Gen3 Roadmap, (US DOE, 2016).

Heat transfer medium	Challenges	Risks
High-temperature molten salt	Operating molten salt at higher temperatures than standard solar salts can tolerate	chemical stability at high-temperatures; freezing at low temperatures; chemical compatibility with containment materials and sCO ₂ (in case of leakage); corrosion; costs
	containment materials (alloys)	chemical compatibility with sCO ₂ and molten salt; costs
	salt-to-CO ₂ heat exchangers; do not exist at the moment but are under development; high-pressure, high-performance heat exchangers with very low pressure drop on the CO ₂ side are required	thermal shock; breakage through freezing of salt; compatibility with sCO ₂ and molten salt
Inert particles	suitable particles with high durability, high solar absorptance, low sintering and low costs	attrition; abrasion; costs
	particle-based receivers	control of particle mass flow and distribution; efficiency; particle loss (open receivers); receiver material durability and costs
	particle storage	particle flow control; abrasion; thermomechanical stability of containers;
	particle-to-sCO ₂ heat exchangers	erosion; particle flow control; costs
	particle lift and conveyance	heat loss; particle loss; parasitic power requirement; longevity; costs
Pressurised gas	receiver design	efficiency; pressure drop; leakage; corrosion; overheating; creep; fatigue; flow control; cost
	heat transfer fluid and circulator	corrosion; cost
	thermal energy storage (phase-change material)	efficiency; charge/discharge rates; cyclability; corrosion; freezing; cost

Note: sCO₂ is super critical CO₂, meaning CO₂ maintained at a pressure above its critical point of 7.39MPa.

Comparing the number and significance of the technical challenges and risks involved, pressurised gas-based systems appear to be a more likely near-term technological pathway, while particle-based systems still need to overcome a number of crucial technical challenges and risks and must prove performance over some years of continuous operation before they can be

deployed commercially. The viability of high-temperature molten salt based systems hinges on the availability of suitable molten salts that can be operated over the required temperature range and are compatible with affordable containment materials.

In the long term, particle-based systems could be advanced to include both sensible as well as latent heat thermal energy storage by using reactive particles that are simultaneously heated and “charged” chemically in the solar receiver and stored for later cooling and chemical “discharge” to provide high-temperature heat. Reactive metal oxide materials, such as manganese and cobalt oxides and mixed metal oxides of the perovskite structure are currently the subject of research and development. These materials can typically be heated to temperatures of 1000°C or more and could give access to storage temperatures suitable for combined Brayton-Rankine power cycles with thermal efficiencies of up to 60%, as well as for supercritical CO₂ (sCO₂) power cycles (see section 2.2.2).

Direct sCO₂ heating receivers have initially been considered but have been omitted from further consideration within the CSP Gen3 Roadmap (Neises and Turchi, 2013). Reasons include the high pressures of around 200 bar that would be required in the receiver and the HTF piping system, which would likely result in very high costs. In addition, the control of the sCO₂ cycle directly coupled to the solar receiver under transient solar energy conditions is considered an additional challenge (Mehos et al., 2017).

R&D activities range from fundamental to near term / applied. It is reasonable to expect that tax payer funding fractions should range from close to 100% at the fundamental end to close to zero at the most commercial end. All the identified global R&D priorities should be considered for action in Australia where there is strong commercial involvement. R&D activities also have a major role in education and capability building, so the benefits of these aspects should also be considered.

It can be observed, however, that there is a tendency for interested individuals (in any country) to begin investigations by designing / building new concentrators from first principles. Given the maturity of the industry globally, this can often be needless reinvention.

It should also be noted that the benefits of these technology improvements are not additional to the empirical learning curve predictions, they are rather a bottom up justification as to how the technical improvements that are assumed can actually be achieved.

Where a contribution to technical improvement is categorised as ‘step change’ it should not be assumed that its successful development will result in a sudden change in LCOE for the industry. A step change in technology will be taken up slowly as financiers will apply risk premiums to early projects and only accept them at smaller scale. A key pertinent example in this regard is the use of tower systems with direct heating of molten salt. This is a major step change away from trough systems with oil based HTF. The approach was first demonstrated at scale in around 1990, it took over a decade for the first commercial scale (GemSolar 19MW) plant to be completed, this has

run successfully for several years and now 28 years after the first project, there are 4 separate 100MW scale systems under construction around the world. Even these plants are considered high risk and indeed the most advanced, the Crescent Dunes plant in Nevada, has taken longer than anticipated to solve its commissioning issues.

9. CONCLUSIONS

CSP is a global industry with track record of successful plants over more than 30 years. Strong deployment growth re-commenced in 2005 with initiatives lead by Spain, this growth has slowed since 2014 although there is a known pipeline of projects and more countries are including it in their future generation mix.

With 5.1 GW installed at the end of 2017, CSP is at a level similar to PV 10 to 15 years ago or wind 20 years ago. Probability analysis of projects under construction planned, suggests that at least 8.5GW will be built by 2024. Strong policy action in key countries can easily accelerate this.

By far the majority of current systems use trough concentrators with thermal oil based heat transfer. The year on year generation levels of these trough plants shows high levels of reliability, notably including the original plants built in the US over 30 years ago.

Two tank molten salt energy storage is now part of 44% of the total installed capacity, it has become the industry standard for thermal energy storage and will likely remain so for at least five to ten years.

Tower systems with direct molten salt heating have become increasingly favoured due to their higher achievable temperatures increasing power block efficiency and making the use of molten salt thermal storage more cost effective. However while there are four large systems currently being commissioned or under construction, there is so far only one such system that has operated reliably for several years to date.

So far, despite excellent solar resources and a highly capable R&D effort, Australia has not engaged with CSP in a serious manner. The increasing penetration of variable renewable generation from wind and PV has shifted attention to the need for a future level of dispatchable renewable electricity generation. In this context CSP is an option that has the potential to be cost competitive with other dispatchable renewable options. With around 15 GW_e of baseload coal plants expected to retire by 2040, establishing a modest compound growth rate in CSP installed capacity in Australia, would allow a significant fraction of that coal capacity to be replaced in an orderly and timely manner.

Globally the industry favours systems built at around 100MW_e for cost effectiveness. However there are many systems built at 50 MW and smaller systems are technically possible. Smaller systems however face reduced turbine efficiencies higher relative O & M costs and reduced economies of scale. Despite this if extra value can be derived from network support in fringe of grid opportunities. Whilst the first plants in the 100MW_e scale may seem like large undertakings, it needs to be seen in the context that around 15 of these is needed to replace one large scale coal plant. Support for systems in the 10 – 50MW_e range may make sense however considerably

higher costs of energy are likely and agencies and policy makers need to be wary of unrealistic expectations.

There is much innovation continuing globally and in Australia. A key area is via super critical CO₂ turbines supported by higher temperature energy collection and storage. This offers potential for lower cost energy and smaller and more modular systems. This potential must however be viewed realistically as it will be many years before a new power cycle can be expected to take over from steam turbines.

Overall with increasing attention paid to the need for dispatchable renewable generation in addition to variable generation from PV or wind, the coming years should hold considerable opportunity for CSP both in Australia and around the world.

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APPENDIX A. LCOE METHODOLOGY

A definitive description of methodologies for the financial analysis of energy systems is available from NREL (Short et al 1995).

The basic formula for evaluating Net Present Value (NPV) is:

$$NPV = \sum_j \frac{C_j}{(1 + DR)^j}$$

where the cash flows C_j are those occurring at time (year) j and DR is the discount rate¹⁹.

Cash flows can be measured in either nominal or real (independent of inflation) currency units. The discount rate can be either nominal, or real. NPVs can be calculated using real currency cash flow measurements together with real discount rates, or nominal currency cash flow measurements with nominal discount rates; the same NPV will be obtained in either case

For a CSP system, the key cashflows are the initial capital investments (negative), ongoing Operation and Maintenance costs (negative), the costs of ongoing inputs such as fuel for hybrid operation or water for cooling (negative) and revenue from direct energy sales (positive) and possible provision of ancillary services (positive).

Key parameters are the discount rate and the assumed lifetime of plants, both of which have a significant impact on overall NPV results. A longer assumed plant life and a lower discount rate both work to improve NPVs for renewable generation. If the “marketplace” assesses that a project or technology is “high risk” this leads to the use of shorter lifetimes for amortisation and application of higher discount rates.

The Levelised Cost of Energy (LCOE) is the most frequently used economic performance metric for power generation plant. It is defined as the constant per unit cost of energy which over the system’s lifetime, will result in a total NPV of zero. In other words it is the “break even” constant sale price of energy.

LCOEs can be in real or nominal terms, which can be confusing because they are expressed in year 0 dollar values in either case. A nominal LCOE represents a hypothetical income that declines in real value year by year, whereas a real LCOE has a constant “value”. Since the total NPV via either method must be the same by definition, the nominal LCOE will be the higher of the two. Real LCOEs are typically used for future long term technology projections, whereas nominal ones are often used for short term actual projects.

¹⁹ This is the most commonly recognised form of NPV on the assumption of annual compounding. Compounding can actually be done on any time scale including continuously, also in a strict mathematical sense, i is a fraction per unit time and is multiplied by the compounding time interval (in this case 1 year).

$$LCOE = \frac{NPV(lifecycle\ costs)}{\sum_1^N \left(\frac{(annual_generation \times (1-T))}{(1+DR)^j} \right)}$$

Where T is the tax rate

From a pure societal perspective, it can be argued that tax issues can be left out of the LCOE. However for the perspective of a commercial entity owning a system, the prevailing assumption is that, to break even, it must be assumed that energy produced is taxed at the standard corporate tax rate. Against this, interest, depreciation and operating costs are tax deductible.

Detailed, project specific LCOE evaluations are based on complex spreadsheets summing every discounted cash flow over the system lifetime, which are then solved iteratively to establish the real dollar value of energy which gives the total NPV of zero.

Issues that are typically encountered include:

- Debt financing may be paid off over a different time scale to equity
- Tax benefits may apply in different jurisdictions
- Tax deductible depreciation may apply over a shorter timescale than the project.
- Construction is staged over several years and subject to higher interest rates for finance
- System output may take some time to stabilise as commissioning processes proceed after first start up.
- System output may be subject to other predictable variations over time (such as a component with known degradation rate).
- Major overhaul type expenditures may be predicted at certain times in addition to overall continuous O&M.
- Various inputs may be subject to different escalation rates.

All these issues are project specific, depending on technology type, developer status and site chosen.

Studies that report LCOEs for CSP systems and other generation types are often poor at documenting all input parameter values and the methods used in a comprehensive way.

The life cycle NPV calculation is embodied in the following formula:

$$NPV_{LC\ costs} = EQ - \sum_1^{ND} \frac{DEP \times T}{(1+DR)^j} + \sum_1^{NL} \frac{LP}{(1+DR)^j} - \sum_1^{NL} \frac{INT \times T}{(1+DR)^j} + \sum_1^N \frac{AO \times (1-T)}{(1+DR)^j} - \frac{SV}{(1+DR)^N}$$

Where:

- EQ is the initial equity contribution from the project developer
- DR is the nominal discount rate
- ND the period (number of years) over which the system can be depreciated for tax purposes
- DEP is the amount of depreciation in a year
- T is the tax rate applying
- LP is the annual loan payment
- INT is the reducing amount of Interest paid each year as the loan is paid off
- NL is the term (number of years) of the loan
- AO is the annual operations cost which could be calculated from fixed and variable contributions as needed
- N is the project lifetime
- SV is the end of project life salvage value.

The simplifying assumptions used are:

- The analysis begins from the time of plant commissioning.
- Annual energy production is assumed constant over project life.
- The Equity contribution is assessed at the beginning of year 1 and so is assumed to have all costs of construction finance rolled into it.
- Depreciation is linear in nominal dollars.
- Loan payments are constant for each year of the loan and are in nominal dollars based on amortisation of a debt across a loan term using the standard annualisation formula.
- Annual O&M costs are constant per year in nominal dollar terms across project life. (this is possibly the most significant, since it doesn't reflect the lumpy expenditure likely on component overhaul).

To aid in understanding, LCOE can be simplified further if tax is not considered and the cost of capital (both debt and equity) can be rolled into a single discount rate. The result is:

$$LCOE = \frac{(F_R + O \& M_{fixed})C_0}{PF_c} + O \& M_{variable}$$

Where:

P is the nameplate capacity of the system

F_c is the capacity factor

C_0 is the total initial capital cost and

$$F_R \equiv \left(\frac{DR(1 + DR)^n}{(1 + DR)^n - 1} \right)$$

is the 'capital recovery factor' and is dimensionally the same as the discount rate. The capital recovery factor represents a rate of repayment that covers 'interest' plus paying off the capital in the system's lifetime.

Many studies report a Weighted Average Cost of Capital (WACC) which may be implied as being for use with this LCOE formula as the effective discount rate. There are a number of published formulas for WACC and these can also often include the tax rate, implying that they could be used in the simple formula. This is difficult and, given the lack of transparency in methodologies, should be treated with caution.



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